uniongas
An Enbridge Company

January 19, 2018

BY COURIER & RESS

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

RE: EB-2017-0255 – Union Gas Limited - 2018 Cap-and-Trade Compliance Plan Issue 1.10.1 Renewable Natural Gas - Interrogatory Responses

Dear Ms. Walli,

On November 9, 2017 Union filed its 2018 Cap-and-Trade Compliance Plan application with the Ontario Energy Board (the "OEB" or the "Board"). On January 8, 2018, at the request of OEB Staff, Union filed an Update to its application to reflect changes to redactions. Union's filings are in compliance with the Board's EB-2015-0363 Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap-and-Trade Activities (the "Framework").

In accordance with the Framework, there are three categories of information which may be included within a natural gas utility's Compliance Plan: public information, confidential information, and Strictly Confidential information. Further, certain aspects of Union's Compliance Plan were deemed as "Strictly Confidential", specifically areas of Auction Confidential and Market Sensitive content. This content is to be reviewed only by Board Staff and the Board panel assigned to review and decide this Application.

In this context and pursuant to Procedural Order No.1 (dated December 28, 2017), please find attached Union's responses to interrogatories on "Non-confidential Information" related to Issue 1.10.1 on the draft issues list. These responses will be filed on the Board's RESS and copies will be sent to the Board.

With respect to its response to OEB Staff interrogatory 3 (Exhibit B.Staff.3 g)) on "Strictly Confidential Information", Union has filed these with Board Staff directly. These responses will not be filed on the Board's RESS.

In addition, certain interrogatory responses pertaining to Energy Probe interrogatory 2 (Exhibit B.Energy Probe.2 f) Attachment 8, p.6 and Attachment 9, p.11) and Consumers

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Union Gas Limited

Council of Canada interrogatory 2 (Exhibit B.CCC.2), have been provided to the Board in confidence under separate cover due to their commercial sensitivity.

If you have any questions with respect to this submission please contact me at 519-436-4558.

Yours truly,

[original signed by]

Adam Stiers
Manager, Regulatory Initiatives

Encl.

cc: C. Smith, Torys
M. Seers, Torys
Valerie Bennett, OEB Case Manager
Ljuba Djurdjevic, OEB Counsel
Lawren Murray, OEB Counsel
EB-2017-0255 Intervenors

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit 1 / p. 6
Exhibit 3 / Tab 1 / p. 22, #5

Preamble: Union Gas notes that it considered the results of the OEB's Marginal Abatement Cost Curve (MACC) in its 2018 Compliance Plan filing.

The MACC found that RNG is significantly more expensive on a cost per tonne basis than customer abatement programs.

Union Gas also notes that: "Union has completed analyses using the MACC report and the underlying Conservation Potential Study ("CPS")… and has determined that within the existing DSM Framework and considering the cost-effectiveness filter for abatement within the (Cap-and-Trade) Framework, there is no incremental customer abatement that would be prudent to pursue at this time".

Union Gas also states that "while the MACC provides an effective basis for gauging potential abatement measures and their relative costs, it is not definitive. That is, it should be applied in conjunction with other factors critical to the decision making surrounding abatement opportunities, such as:

- Practical realities, such as timing or sequencing dependencies…;
- Market receptivity and adoption factors which may be independent of costs;
- Interactions between programs (cumulative effects), where the potential of each program could be reduced if another measure were pursued first; and
- Other considerations such as customer input, technology adoption, alignment with other investment priorities and qualitative benefits."

Question:

a) Please explain what Union Gas means by the "cost-effectiveness filter for abatement within the Cap and Trade Framework".

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

c) Please provide all information, including specific references to the MACC and CPS, that Union Gas used to determine that "there is no incremental customer abatement that would be prudent to pursue at this time".

d) Will the OEB's decision to approve/not approve the Union Gas RNG procurement model impact other abatement activities that Union Gas is considering? If so, please discuss how. Please provide all relevant analysis and documentation.

   i. If Union Gas' RNG procurement model is not approved, would Union Gas invest in other abatement activities? Please explain and provide all relevant analysis and documentation.

e) Does Union Gas agree that the cost-effectiveness of RNG is predicated on provincial government funding?
   i. If yes, has Union Gas had any discussions with the provincial government in regards to obtaining similar funding to support other abatement opportunities? Please provide all relevant supporting documentation.
      1. Please explain what types of customer abatement activities Union Gas has been discussing with the provincial government.
      2. Please explain whether, and how, any customer abatement activities being discussed with the provincial government are different from the customer abatement opportunities for which Union Gas determined that "there is no incremental customer abatement that would be prudent to pursue at this time".
   ii. If no, please explain. Please include supporting analysis and documentation.

f) Please explain how the factors other than the MACC identified in Exhibit 3, Tab 1, p. 22, #5 influenced Union Gas' decision to pursue RNG and not any other abatement activities. Please provide all supporting analysis and documentation.

Response:

a) Cost-effectiveness refers to one of the guiding principles defined in the Cap-and-Trade Framework. In the context of the Compliance Plan, this is one criteria that applies to measures that could be employed by the utilities, whether that be the procurement of compliance instruments or abatement. The Framework also identifies that performance metrics will be considered when evaluating cost effectiveness and reasonableness; in particular, the cost per tonne of compliance instruments and its comparison to procuring emissions units (the cost of carbon).

   In the case of RNG procurement, Union also currently considers cost-effectiveness in the context of gas supply purchases. Since the Marginal Abatement Cost Curve ("MACC") identifies that RNG is not currently cost effective relative to the cost of carbon, and is more expensive than conventional natural gas, Union's proposal is contingent upon available provincial funding. This funding keeps customers indifferent between RNG and the forecasted cost of conventional natural gas supply and its related cost of carbon. As stated in Union's response at Exhibit B.CCC.1, the RNG market in Ontario is in its infancy. The MACC Report also reflects this fact, and cited the lack of up-to-date information upon which to base its analysis (using the Canadian Biogas Study that was over four years old at the time). In general terms, Union would expect that as the RNG market in Ontario develops and expands, economics could improve over time through improved technology and competitive forces. As a result, the cost-effectiveness of RNG could improve. Union would expect that as this occurs, future MACC Reports will reflect RNG more favourably relative to other abatement alternatives. Since the RNG proposal is reliant upon government funding to minimize the financial impact on customers cost-effectiveness as a filter for RNG is not applicable in the same way that it would be for other abatement measures, such as energy efficiencies. For energy efficiency measures, the cost effectiveness filter refers to the use of the Long Term Carbon Price Forecast ("LTCPF"), the MACC and the Conservation Potential Study ("CPS") to determine which measures are appropriate to fund when compared to the cost of carbon.

b) Please refer to part a) above and part f) below.

c) Please refer to Exhibit 3, Tab 4, Appendix A of Union's 2018 Compliance Plan application for a complete review of analysis conducted by Union using the LTCPF, MACC and CPS.

A summary of the analysis Union completed, including how the MACC and the CPS were utilized is provided below:

Conservation Potential Report (CPS):
The first report, or data set, analyzed to determine if there was additional cost-effective energy efficiency abatement potential was the CPS. Cost-effectiveness was determined by comparing the cost of purchasing allowances to the cost of pursuing incremental abatement opportunity. The CPS provides potential energy savings under three scenarios: constrained (current levels of DSM funding), semi-constrained (approved 2015-2017 OEB budget, and gradually increased until doubled by 2020), and unconstrained (unconstrained budget). Union analyzed the CPS data from a provincial perspective, as the budgets provided within the CPS were not broken down at the utility level. For purposes of this analysis, Union used the CPS constrained scenario because it represents the best proxy to Union and EGD's current DSM budgets and free ridership impacts. Next, Union identified the incremental m3 and tonnes of GHG abatement potential available when moving from the current CPS Constrained Scenario to the CPS Semi-Constrained Scenario; the same from the current CPS Constrained Scenario to the CPS Unconstrained Scenario; and the associated budget required to achieve the savings.

Utilizing the calculated Marginal Cost ($/Tonne) and the minimum, mid-range and maximum LTCPF, Union analyzed whether or not investing in incremental abatement potential would be cost-effective over a 15 year period, an average measure life.

Marginal Abatement Cost Curve (MACC) Report:
In addition to the CPS, Union utilized the MACC report released by the OEB to determine if, from the utility's perspective, there is any incremental cost-effective m^3/GHG abatement above and beyond the targets identified in the 2015-2020 DSM Plan. Since the MACC does not separate the total customer emission abatement potential from existing DSM activities underway as per the OEB's Decision and Order in EB-2015-0029/0049, this analysis focused on comparing the total abatement identified within each MACC to the abatement opportunity being targeted within Union's DSM Plan. This approach allows Union to understand how much incremental abatement opportunity exists at a macro level, for example in which market Commercial/Industrial ("CI") or Residential does potential incremental abatement exist. To complete this evaluation, the following steps were taken:

1. The abatement potential identified within each MACC was separated into Union and EGD opportunity. This was completed using the percentage breakdown identified in the CPS based on savings identified in the constrained scenario in Union's franchise for 2018-2020. Union assumed that 38%, 42% and 66% of the MACC opportunity is in Union's franchise for the residential, commercial and industrial sector, respectively.
2. Because the opportunity identified in the MACC is in gross savings, Union discounted the MACC abatement opportunity by an assumed free-rider rate for each market. MACC abatement opportunities are adjusted using an assumed free-rider rate for each sector based on existing offerings as filed in Union's 2015-2020 DSM Plan, EB-2015-0029. Union assumed a 5% free rider rate for the residential sector based on the Home Reno Rebate offering, 10% for the commercial sector based on the Prescriptive offering and 54% for the industrial sector based on the Custom offering.
3. Commercial/Industrial Analysis:
    a. After steps one and two above were completed for both the commercial MACCs and the Industrial MACCs, Union combined the CI MACC abatement at the minimum, mid-range and maximum LTCPF scenarios. This was required to compare this CI abatement potential to Union's DSM 2015-2020 plan, as Union's DSM targets are separated by Custom, Prescriptive and Performance Based Program, and not by CI sectors only.
    b. Large volume savings were removed to better align with the MACC abatement opportunity, which removed all large final emitters.
4. Residential Analysis was based on the same approach above

d) The advancement of other abatement activities is not dependent upon the OEB decision to proceed with RNG. Union believes that the pursuit of DSM and other abatement activities is not mutually exclusive, and is taking steps to advance many forms of abatement in parallel. Union has both facility and customer abatement initiatives at various stages of development as described in more detail at Exhibit 3, Tab 4 of Union's application. Please also refer to part f) below.

e) Cost effectiveness of RNG procurement in terms of the utility impact on its ratepayers is subject to government funding. Union cannot comment on how the government determines its Climate Change Action Plan ("CCAP") funding priorities. However, Union has observed that in the CCAP, RNG is estimated at a cost of $5/tonne, lower than any other quantified measure.[1]

i) 1. Union has met with provincial ministries in relation to other applicable measures requiring funding and initiatives that can be effective in reducing GHG emissions. These include energy efficiencies, CNG and geothermal. As identified in evidence,[2] Union is also investigating new technologies, some of which in the future may also rely on government funding as a means to advance these measures within existing regulatory frameworks. The new technologies Union is investigating are described in Exhibit 3, Tab 4. The presentation at Attachment 1 is representative of these types of initiatives and discussions Union has had with the province.

2. Union has had energy efficiency program discussions with government focused on Residential, Commercial/Industrial, Indigenous and Market Transformation opportunities that complement existing DSM programs. Union has engaged in these discussions in an effort to ensure that CCAP funded energy efficiency programs maximize GHG reductions, do not duplicate DSM spend, and that they create a seamless customer experience.

f) This response addresses the interrogatories asked by OEB Staff and intervenors in regards to how the MACC or other means of evaluation were applied to RNG, particularly relative to other abatement alternatives (such as energy efficiency programs) or procurement of credits (e.g. allowances, offsets). RNG was one measure evaluated in the OEB MACC report; other measures focused on energy efficiency opportunities. The MACC report identifies that RNG is not currently a cost-effective measure relative to the Long-Term Carbon Price Forecast.[3] In addition to the MACC, Union has also considered other factors as part of its assessment of

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[1] CCAP, page 68
[2] Exhibit 3, Tab 4, p. 25-60
[3] The long-term carbon price forecast used was the ICF report issued by the OEB on May 31, 2017.

RNG including the availability of government funding, customer impacts, market readiness, technology readiness, and consistency with public policy.

Through ongoing discussions with government, Union and Enbridge have jointly proposed the RNG program details required to secure provincial funding. The availability of this funding is the primary impetus behind Union and Enbridge's ability to introduce RNG into the natural gas supply stream, and minimize the cost impact to customers. By minimizing the cost impacts to Union's customers this funding makes them indifferent between conventional natural gas and RNG. This approach acknowledges that customers have paid the carbon price on their natural gas bills, and therefore there should not be also exposed to the high price of RNG when there is government funding available. The use of government funding to minimize the financial impact of RNG removes the applicability of quantitative analysis and the comparison of RNG relative to other measures or the cost of carbon.

Union believes that RNG and other customer abatement programs (e.g. energy efficiency programs) are not mutually exclusive, but are complementary in reducing GHG emissions. While RNG aims to "green" the gas supply portfolio by replacing conventional natural gas with carbon-neutral RNG, energy efficiency programs reduce the amount of energy consumed (and the emissions produced). Energy efficiency measures often require action and potentially capital investment on behalf of the customer, whereas RNG requires no capital investment by the customer and is deployed directly into the natural gas stream, leveraging existing storage and transmission infrastructure.

Union believes that both RNG and energy efficiency programs are a viable and effective means of reducing GHG emissions, and it has been working at advancing both initiatives. Union has a history of successfully designing and delivering robust DSM programs since 1997. Union has and will continue to evaluate new potential programs and technologies that can be introduced within its DSM portfolio.

The Federal Government's Clean Fuel Standard initiative has also encouraged Union's RNG proposal. RNG satisfies the hybrid approach outlined in the Clean Fuel Standard discussion paper by providing both renewable content and lower carbon intensity when compared to conventional natural gas. The Government of Canada's Clean Fuel Standard: Discussion Paper was released February 2017 by Environment and Climate Change Canada. The Paper includes fuels used in industry, homes and buildings as part of its scope. Clean Fuel Standard Regulations will use a life-cycle approach to set carbon intensity values for liquid, gaseous and solid fuels with a goal of reducing emissions from fuels used in transportation, industries and buildings. In connection with the discussion paper, The Clean Fuel Standard regulatory framework was issued in a Government Notice (Vol. 151, No. 51 — December 23, 2017) identifies that consideration will be given to setting volumetric requirements for renewable content and may also require GHG performance standards and that the distributors of natural gas are will be the regulated party required to comply with the specific requirements for the fuels that they distribute.

Enbridge in Ontario

27 September 2017

ENBRIDGE

The New Enbridge

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

Enbridge in Ontario

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

ENBRIDGE
Life Takes Energy™

Key Projects of Interest:

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

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

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

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

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

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

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

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

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

Utility Integration

One Company. One Team. One Message.

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

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

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

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

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ENBRIDGE
Life Takes Energy™

Enbridge – Part of the Solution

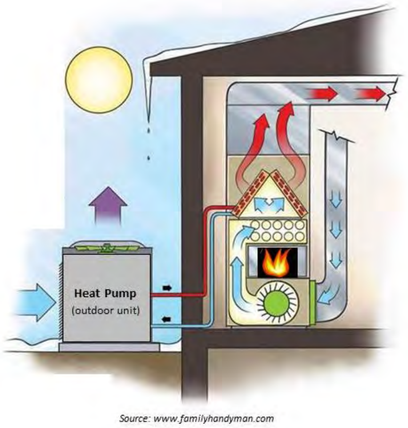
Supporting the Transition to the Low Carbon Economy

Energy Conservation

Average Residential Customer Usage Reduced Natural Gas use by 21%

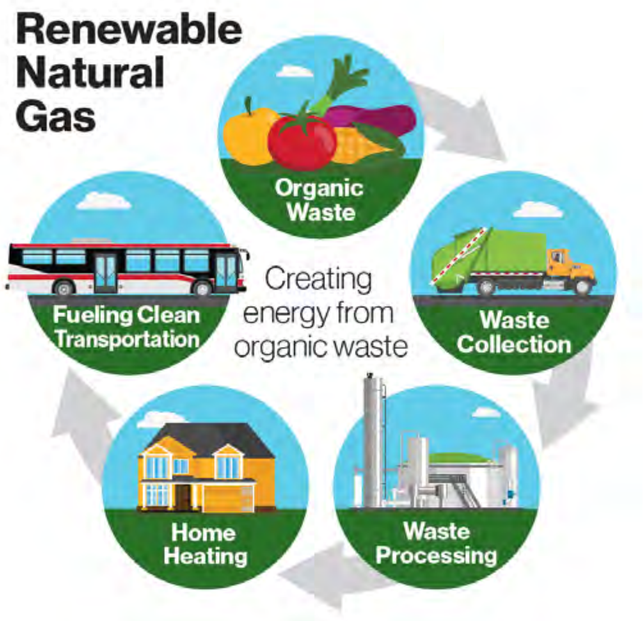
Residential Customers save $2.67 for each dollar spent on natural gas conservation
(Environmental Commissioner of Ontario, 2016)

Technology & Energy Optimization



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

Decarbonize the Gas Supply with Renewable Natural Gas & Hydrogen



ENBRIDGE
Life Takes Energy

Energy Conservation

Proven Leadership, Expertise & Speed

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

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

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

Moving forward:

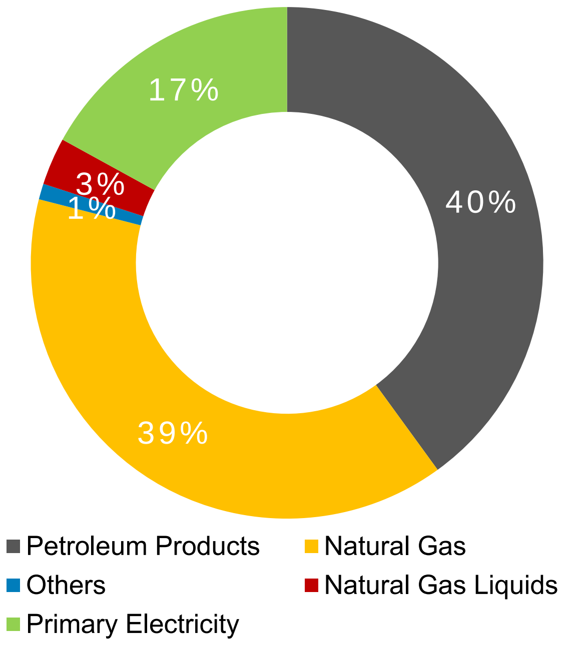
- Reach of the gas utilities: 3.5M customers (78% of homes); New GIF program reaches all Ontarians
- Enbridge's proposals to partner with GreenON beyond the existing Green Investment Fund Partnership would allow further cost-effective opportunities to further reduce emissions by leveraging Enbridge's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

Technology & Energy Optimization

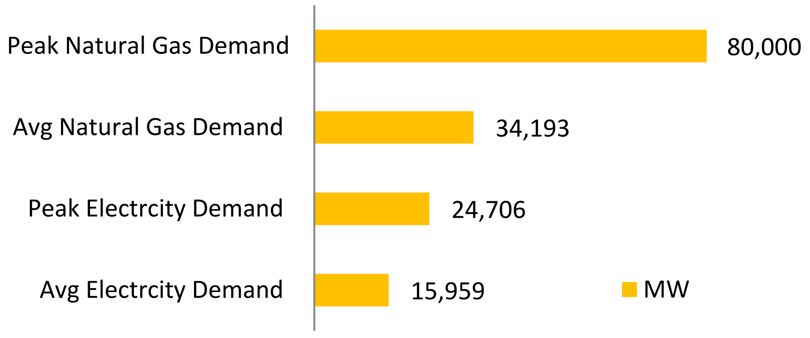
Electrification?

- **While Ontario strives towards its ambitious emission reduction objectives it needs to ensure that our energy systems are as reliable and affordable as possible for consumers.**
- Ontario's natural gas distribution and storage network delivers more than three times the energy on a peak day (equivalent to ~80,000 MW) compared to the electricity system (24,700 MW).
- The most desirable and cost effective electrification utilizes existing infrastructure and does not create the need for new capacity resources, while at the same time displacing fuels to reduce emissions. (eg. electric cars vs home heating)

Primary Energy Use in Ontario (2015)



Ontario Energy Delivery by Infrastructure Type



Decarbonizing Ontario's Natural Gas Supply

Renewable Natural Gas

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

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

- RNG could provide 8 MT CO2e emission reductions by 2030

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

Natural Gas Transportation

Catching Up on Low-Carbon Vehicles

ENBRIDGE
Life Takes Energy™

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

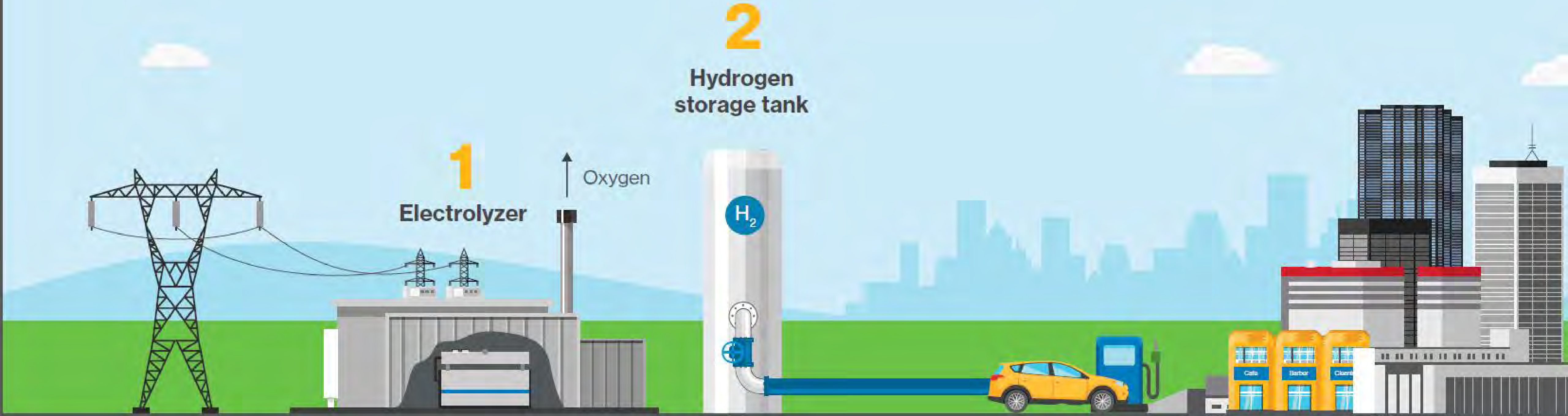
- Natural gas has roughly 20% fewer GHG emissions and is up to 40% less expensive than diesel or gasoline.

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

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

Enbridge Invests in Power to Gas

Future State - Using hydrogen to fuel zero-emissions vehicles



1. Since electricity can't be stored, when there is a surplus, an electrolyzer can take the electricity and use it to split water into hydrogen and oxygen. →
2. The hydrogen that is produced is then stored. →
3. Hydrogen can be shipped directly to refueling stations or to industrial and commercial customers.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit 3 / Tab 1 / p. 22

Preamble: Union Gas acknowledges that in the MACC report, bottom-up detailed analysis of RNG costs and supplies was not publicly available, and data in the report was leveraged from existing studies on RNG where assumptions may not be known or may be outdated. Union Gas acknowledged that this resulted in the MACC displaying a wide range of potential RNG costs and available supplies.

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

Response:

The response at Exhibit B.Energy Probe.2 f) (Attachment 8, p. 2) includes a presentation made to the MOECC specific to potential RNG projects in the province. This is not meant to be a comprehensive list, nor does it provide greater clarity towards the wide range of potential costs for the MACC. Union has not completed or commissioned any additional analysis or gathered any additional information beyond what ICF used to generate the MACC report.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit 3 / Tab 1 / p. 22, #4

Preamble: Union Gas states that in the MACC Report, "the value of offsets has not been included in the RNG economics, recognizing that final offset regulations and protocols have not yet been released." Union Gas further states that this is important because "offsets can represent another value stream associated with RNG which could impact its cost, its potential production level, and the timing of its development."

Question:

a) Please explain how offsets could represent "another value stream."
b) Please explain how this value stream could impact the cost, production level, and timing of RNG development.
    i. Please explain how this impacts Union Gas' potential procurement of RNG, including the cost of RNG and the timing of procurement.
c) What is Union Gas' expected "value of offsets" in $/tonne of CO2e? Please explain and provide supporting data and analysis.
d) Please explain how Union Gas expects the "value of offsets" to affect Union Gas' proposed RNG procurement and funding. Please provide all relevant supporting documentation and analysis.
e) Please explain how Union Gas expects the value of offset credits could affect the amount Union Gas would pay to RNG suppliers through its RNG funding model. Please provide all relevant supporting documentation and analysis.
f) Please explain whether the Ministry of Environment and Climate Change and/or provincial government has confirmed that offset credits will be available for RNG.
g) Does Union Gas plan to be an offset project developer and/or offset supplier?
    i. If yes, please confirm that the laws and regulations governing cap and trade and offset credits in Ontario would allow a capped participant such as Union Gas to undertake this business activity. Please explain whether Union Gas would undertake this business activity through an affiliate or as a regulated utility.
    ii. If no, please explain how Union Gas could take advantage of the offset value stream and how this value stream could affect the cost of RNG that Union Gas would procure.

Response:

a) RNG can be monetized in two value streams:

    1 - By using the RNG commodity to reduce Union's Cap-and-Trade compliance obligation, and

2 - Through the use of offset credits related to the capture of the methane used to produce the RNG. Offset credits can only be generated from projects that meet the eligibility requirements of the Offset Regulation and the applicable offset protocol. Offset credits can be sold to a Cap-and-Trade participant in the compliance carbon market or the voluntary offsets market.

b) In the event that RNG production becomes eligible for creation of carbon offsets for use in Ontario's Cap-and-Trade program, this value stream may impact the price that producers charge for RNG. For new RNG projects, the value provided by offset credits could reduce the amount of provincial funding required to make RNG a cost effective abatement opportunity. For RNG contracts finalized prior to the creation of the offset credit value stream, the value provided by offset credits would accrue to the producer and therefore there will be no impact to Union or ratepayers.

c) As outlined in Exhibit 3, Tab 3, p. 9, offset credits generally trade at a discount to carbon allowances, but due to the varying risks and uncertainties outlined, it is difficult to assess or forecast individual offset prices. For illustrative purposes, a Golden California Carbon Offset credit for immediate delivery was priced between $13.50 and $13.90 USD/tonne on January 12, 2018, which is an approximate 6-9% discount to carbon allowances trading at the same time. Prices for offsets can vary significantly depending on the terms of the offset contract, the type of offset, the jurisdiction of the offset, the location of the offset project for which the offset credit was created, the invalidation risk associated with the offset, and the relative value of carbon allowances at the time of the transaction.

d) See response to part a) above.

e) See response to part a) above.

f) Union cannot confirm that offsets credits will be available for RNG; however, the MOECC has stated its intention to recognize GHG reductions from biogas recovery and use from different sources (landfill recovery, anaerobic digestion of organic waste, composting and incineration of organic waste).

The offsets market in Ontario is very much in its infancy. Final Offset Regulations were published on December 28, 2017, along with the final Landfill Initiative Protocol for landfill methane destruction. The Protocol recognized upgrading of landfill gas into RNG and introduction of RNG into the natural gas distribution system as an eligible carbon offset (landfill gas destruction) activity. Eligibility requirements (landfill size) will limit the number of RNG projects that will qualify as offset credit projects, and will also limit the amount of carbon offsets that individual RNG projects can generate. No other offset credit protocols have been finalized. While landfill gas is not the only potential source of RNG, it is not known if other sources of RNG will be eligible to generate offset credits.

g) The Climate Change Mitigation and Low-carbon Economy Act, 2016 ("Climate Change Act") outlines prohibitions on the disclosure of certain information. These prohibitions are reflected in Section 4 of the OEB's Cap-and-Trade Framework. This question refers to information that has been classified as Strictly Confidential. In keeping with the legislation and with the best interests of ratepayers in mind, such information must remain Strictly Confidential in order to maintain the ability to effectively execute on Compliance Plans.

Generally speaking, if there is a value stream for offsets related to RNG, this could make RNG more economically attractive to producers and encourage the development of the market in Ontario. The development of a robust market with more production could result in lower costs for RNG that Union would seek to procure.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit 3 / Tab 4 / p. 2
Exhibit 3 / Tab 4 / p. 19 and p. 22, "RNG procurement"

Preamble: Union Gas states that its plan for RNG procurement is subject to Ontario government funding. Union Gas also states that procurement for RNG will begin with an RFP process which will then be used to negotiate the contract with the province to secure funding. Once provincial funding is secure, Union Gas would then contract directly with RNG producers for long-term fixed price contracts. The province would pay Union Gas the provincially funded portion of the RNG contracted price.

Union Gas also states "earlier in 2017, Union and EGD developed an RNG proposal for the province that will achieve the market objectives of the province by providing a mechanism to facilitate RNG procurement funding and cost recovery." Union Gas indicates it intends to procure RNG on the basis outlined in this proposal.

Question:

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

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

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

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

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

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

g) Union Gas states that in 2017, Union Gas and EGD "…developed an RNG proposal for the province…" Please file this RNG proposal with the OEB.

Response:

a) The Climate Change Act requires that the province use Cap-and-Trade proceeds to support the reduction of greenhouse gas by investing in green projects. Union's RNG proposal supports this government policy as the Climate Change Action Plan ("CCAP") allocates up to $100 million of Cap-and-Trade proceeds for the implementation of a renewable content requirement for natural gas and to provide support to encourage the use of cleaner, renewable natural gas in industrial, transportation, and buildings sectors. The government has identified that it plans to invest proceeds from the carbon market to "help consumers with the cost of shifting to RNG, as it currently costs more than conventional natural gas."[1] Union's RNG proposal ensures that ratepayers do not pay for the price of carbon; through Cap-and-Trade included on the gas bill, as well as the premium that RNG requires.

b) It is Union's understanding that funding will be made available by the government in 2018. Union will calculate the proportion of the RNG price that will be subject to funding for the term of the contract based on the proposed framework. Volumes will be defined for each RNG contract and Union will only contract and purchase RNG to the extent that funding provided by the government is adequate to cover the term of the RNG contracts.

c) It is Union's understanding that funding will be secured in advance of contracting for RNG. This approach will ensure that adequate funding, calculated as described in part b) above, is available for the full term of the RNG supply contracts.

d) As discussed in parts b) and c) above, cessation of provincial funding need not constitute force majeure as adequate funding will be made available and set aside before Union contracts for RNG.

e) The RFP will require compliance with published utility gas quality specifications and necessary credit approvals. In addition, it is expected the RFP respondents will provide an RNG price, a carbon reduction estimate, a contract term, expected production volumes, a supply source description and location, and reliability of supply. The RFP will be subject to

[1] Ontario's 2017 Long Term Energy Plan, published October 26, 2017, Chapter 6 Shifting to renewable natural gas, p. 114.

receipt of sufficient provincial funding and OEB approval of Union's RNG procurement proposal, including the methodology to establish long-term gas supply and carbon prices in rates.

f) Union is in the process of developing its initial RNG RFP and expects to issue this RFP by early February. Information on Union's initial RNG RFP will be communicated to industry associations and interested parties, and information will be available on the Enbridge Gas Distribution Inc. ("EGD") and Union Gas Limited ("Union") websites. Additionally, a general information session will be held early in the response period.

g) Please see the response at Exhibit B.Energy Probe.2 f).

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit 3 / Tab 4 / p. 19

Preamble: Union Gas states that biogas producers require longer term contracts to support capital investments in RNG production, and for this reason Union Gas expects to enter into RNG procurement contracts with terms of up to 10 years, subject to provincial funding.

Question:

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

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

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

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

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

Response:

a)-d) Union has received consistent feedback in its discussions with potential RNG producers including landfills, waste water treatment plants, industrial sites, and biogas associations requesting:

I. a dependable market demand for RNG
II. long-term contracts to support investments in RNG production facilities
III. credit-worthy and dependable counterparties to sell RNG to

A 10-year RNG purchase agreement between producers and the utilities addresses this feedback from producers. Some producers indicated they would prefer a 20-year contract term to match the asset life of their facilities. By selecting a 10-year contract, Union feels it is best positioned to:

- Procure RNG at a relatively a low cost ;

- Align its RNG purchase term with the term of the Long Term Carbon Price Forecast;
- Ensure that re-contracting risk is shared between the producers and the utilities during the life of the asset; and,
- Encourage the development of a competitive marketplace.

It is important that Union consider competing priorities for RNG suppliers such as they may wish to use RNG for their own purpose, or other marketing opportunities for their RNG. Other opportunities may emerge after the initial 10-year contract term for RNG, which could include CNG for the transportation market under a Clean or Low carbon fuel standard as currently contemplated by the federal government, replacing higher carbon intensity fuels like diesel.

There is limited market information available on contract term for RNG purchases from other jurisdictions. The information Union was able to find is included below:

British Columbia
FortisBC has at least three renewable natural gas (RNG) supply contracts approved by the British Columbia Utilities Commission (BCUC) with gas supplies. These include:

- a ten (10) year contract with Catalyst Power in December 2010 as part of the on-farm Fraser Valley Biogas Project;
- a fifteen (15) year contract in December 2010 with Columbia Shuswap Regional District (Salmon Arm Landfill Project); and,
- a fifteen (15) year contract in October 2012 with the City of Kelowna (Kelowna Landfill) for a maximum volume of 118,000 GJ per annum.

Québec
On July 7, 2017, Gaz Métro applied to the Régie de l'énergie for approval of renewable natural gas (RNG) contracts ranging from five (5) to twenty (20) years. The Regie has yet to issue a decision in this proceeding.

California
In May 2007, the California Public Utilities Commission (CPUC) approved a ten (10) year contract between Pacific Gas & Electric (PG&E) and Bioenergy Solutions for the procurement of RNG to meet the state's Renewable Portfolio Standard (RPS).
In October 2008, the CPUC approved a ten (10) year biogas contract between PG&E and Microgy. A portion of the gas would come from a facility located in Texas.
In July 2011, the CPUC approved a ten (10) year biogas contract between the Bear Valley Electric Division of Golden State Water Company and Bioenergy Solutions. Bear Valley provides electricity services to approximately 20,000 customers. The biogas would be used to meet the state's Renewable Portfolio Standard (RPS).

Washington
In October 2008, Puget Sound Energy (PSE) entered into a twenty year (20) agreement with Bio Energy Washington to purchase all the pipeline quality gas recovered from the Cedar Hills Landfill in King County. The deal became effective in May 2009.

Vermont
Lincoln Renewable Natural Gas owns and operates a renewable natural gas facility in Salisbury, Vermont.

Lincoln RNG has executed a purchase/supply contract with Vermont Gas Systems for an initial 5-year period. Under that contract, all of the RNG project's remaining RNG output for the first three years of the facility's operation and half of the remaining output for the fourth and fifth years of operation will be sold to Vermont Gas Systems.

On September 6, 2017, the Vermont Public Utility Commission approved a Renewable Natural Gas program for Vermont Gas Systems

e) Union cannot accurately comment on whether or how extending the duration of RNG contracts could impact the price of RNG. The RNG price will be determined through the RFP process and as such will be dependent on the responses received from RNG producers which will include project specific information. Without this project specific information it is difficult for Union to provide an estimate of the impacts of an extended contract term. It is possible that producers could require lower prices for extended contract terms since this would allow a longer period of time to recover their investments derisking the project to some extent.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit 3 / Tab 4 / p. 21, Figure 3

Preamble: Union Gas states that for its procurement model, the forecasted cost of carbon will be determined by the OEB's LTCPF applicable at the time of contracting.

The OEB has committed to updating its LTCPF every year.

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

Figure 3

Renewable Natural Gas Procurement Funding Model

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 9	Year 9	Year 10
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
a) Forecast gas cost ($ / GJ)	$ 3.91	$ 3.95	$ 3.91	$ 4.22	$ 4.22	$ 4.29	$ 4.28	$ 4.68	$ 5.03	$ 5.43
b) Forecast Cost of Carbon ($ / GJ)	$ 0.85	$ 0.90	$ 0.90	$ 0.95	$ 1.00	$ 1.05	$ 1.56	$ 1.81	$ 2.16	$ 2.51
(c) = (d)-(a)-(b) Required Provincial Funding ($ / GJ)	$ 11.24	$ 11.15	$ 11.19	$ 10.83	$ 10.78	$ 10.66	$ 10.16	$ 9.51	$ 8.81	$ 8.06
d) Assumed Cost of RNG ($ / GJ)	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00

Question:

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

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

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

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

Response:

a) Please see Attachment 1.

b) Union used $16/GJ for illustrative purposes only. The RFP is expected to provide a market price. No documentation or analysis was conducted to calculate the $16/GJ.

c) In order to provide the certainty required to enable producers to move forward with RNG production investments a fixed RNG price over a long term contract is required.

d) The following is intended to provide a complete overview of the proposed RNG pricing mechanism and commentary related to ratepayer risks and impacts in response to various related interrogatories received by intervenors.

Union's proposal involves contracting for RNG supply from producers using fixed price, long term contracts. Union is proposing to recover the cost of RNG purchased using three mechanisms:

- The first recovery mechanism is in gas costs based on a forecast cost of gas for the entire term of the RNG contract. This forecast cost is intended to reflect what ratepayers would have otherwise paid for conventional natural gas. In Union's proposal, this impacts system customers who purchase their supply from Union.
- The second recovery mechanism is in Cap-and-Trade costs and will be based on the OEB's Long Term Carbon Price Forecast for the entire term of the RNG contract. Because RNG is a carbon neutral alternative and has lower emissions, when Union purchases RNG, the carbon allowance requirement is reduced. This benefits all customers that Union purchases carbon allowances for, including Union's purchases for operating its own facilities. Union is proposing to recover a portion of the RNG cost in Cap-and-Trade charges to reflect what customers would have otherwise paid for carbon allowances. This charge applies to all customers that pay facility or customer related Cap-and-Trade rates.
- The third and balance of recovery is through government funding. Natural gas customers contribute to Cap-and-Trade program funds through the cost of carbon included in natural gas rates. Access to the Cap-and-Trade funds to support RNG ensures that ratepayers are not paying a premium for RNG in addition to already contributing to Cap-and-Trade in natural gas rates. Government funding provides access to Cap-and-Trade proceeds specifically allocated for RNG, supporting the economic and environmental benefits that RNG can provide in optimizing the use of existing natural gas assets while reducing the province's carbon footprint.

Union will set the price of carbon and natural gas based on the most recent forecast available at the time each RNG contract is finalized. The total RNG and associated forecast gas and carbon price elements will be fixed for the term of the contract, negating the need for Union to update the forecasts which underpin the contract and the allocation of costs each year. This approach ensures the producer's revenue ($/GJ) is predictable and the government funding provided to Union is adequate to support the entire term of the RNG contract.

On an actual basis, the price of natural gas and carbon may be different from the forecast price at the time the RNG contract is negotiated, however, the cost to ratepayers will be at the contracted rate (i.e the forecast cost of natural gas and carbon at the time the RNG contract is finalized and will be fixed for the term of the RNG contract).

Union's RNG procurement will make up a very small portion of its gas supply and Cap-and-Trade compliance plans. Therefore, the impact associated with actual prices for gas and/or carbon being higher or lower than what is forecast is expected to be immaterial.

Renewable Natural Gas Procurement Funding Model

		Year 1 **2018**	Year 2 **2019**	Year 3 **2020**	Year 4 **2021**	Year 5 **2022**	Year 6 **2023**	Year 7 **2024**	Year 9 **2025**	Year 9 **2026**	Year 10 **2027**	Average
a)	Forecast Gas Cost ($ / tonne)	$77.83	$78.63	$77.83	$84.01	$84.01	$85.40	$85.20	$93.16	$100.13	$108.09	$87.43
b)	Forecast Cost of Carbon ($ / tonne)	$17.00	$18.00	$18.00	$19.00	$20.00	$21.00	$31.00	$36.00	$43.00	$50.00	$27.30
(c) = (d)-(a)-(b)	Required GreenON Subsidy ($ / tonne)	$ 223.67	$ 221.87	$ 222.67	$ 215.50	$ 214.50	$ 212.11	$ 202.30	$ 189.34	$ 175.37	$ 160.41	$ 203.77
d)	Assumed Cost of RNG ($ / tonne)	$ 318.50	$ 318.50	$ 318.50	$ 318.50	$ 318.50	$ 318.50	$ 318.50	$ 318.50	$ 318.50	$ 318.50	$ 318.50

Note:

Assumed Heat Conversion Factor M3 to GJ 0.0373

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit 1 / p. 6 and p. 10

Preamble: Union Gas has asked for approval of the mechanism to fund the RNG program and associated cost consequences no later than the end of January 2018.

Question:

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

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

Response:

a) Without a timely OEB decision, Union faces the risk of losing the opportunity to secure provincial funding that will reduce the net cost of RNG. This could compromise Union's ability to support government policy of pursuing RNG as a carbon reduction activity. Additionally, potential Ontario RNG projects may choose to enter into long term contracts to export their RNG into competing markets. This has two effects: i) the RNG is no longer available for the Ontario market and, ii) the cost of future RNG projects will likely increase as project developers typically develop the least cost projects first.

b)
   i. Negotiations with the province for funding are expected to conclude no later than March 2018.
   ii. Initial contracts, including various special provisions and conditions, are expected to be in place with producers by the end of May 2018. These contracts are expected to be finalized by the end of 2018.
   iii. Union does not expect RNG production will be ready for injection to its system until late 2019 or 2020.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit 3 / Tab 4 / pp. 22-23

Preamble: Union Gas states that since its ability to procure RNG is dependent on funding, Union Gas has not included any RNG in its gas supply portfolio for 2018 and has not reflected any related GHG emissions reductions in the 2018 Compliance Plan. Union Gas also states that if it is successful in acquiring RNG supply in 2018, the quantity is expected to be small in relation to Union Gas' 2018 compliance obligation.

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

Response:

The amount of RNG to be procured will depend on the amount of government funding received and the price charged by RNG producers. Union expects that up to $100 million will be granted by the province for the purposes of Union and EGD's RNG procurement programs. Assuming that half of this is available to Union and that the average RNG price and forecast prices for gas and carbon are equivalent to Union's illustrative example in evidence,[1] Union expects it will be able to contract approximately 4.9 PJ of RNG in 2018, to be delivered over the following 10 years. Using an assumed conversion factor of 0.0373 m^3 per GJ, this would amount to approximately 131 million m^3 or 245,000 tonnes of CO_2e.

[1] Exhibit 3, Tab 4, p. 21, Figure 3

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit 3 / Tab 4 / p. 18

Preamble: Union Gas states that "by investing in and supporting RNG, Ontario stands to benefit from the diversification of Union's gas supply portfolio and subsequently the development of a provincial RNG industry. This action satisfies both the interest expressed by the MOE in the development of RNG in Ontario and its inclusion in the Utilities' gas supply portfolios and will support the transition to the low-carbon economy."

Question:

a) Please explain what Union Gas believes its role is in advancing the adoption of RNG to support the government's GHG emission targets and the transition to a low-carbon economy.

b) Please explain whether Union Gas expects to develop a new business that would involve supplying, producing, and/or developing RNG in the future.
   i. If so, please explain what type of new business Union Gas expects to undertake, and within what timeframe.

Please explain whether this would be handled by an affiliate or whether this would be a regulated activity.

Response:

a) Union supports the transition to the low-carbon economy, and believes the natural gas utilities have a role to play in contributing to the achievement of GHG emission targets while balancing energy affordability for its customers. The utilities' size, proximity to large-scale markets, physical assets and established delivery systems can be leveraged to successfully expedite the adoption of new technologies and energy applications, such as RNG. This is entirely consistent with the Cap-and-Trade Framework, which clearly states that "the utilities' Compliance Plans are expected to support the government's effort to reduce GHG emissions in Ontario".[1]

   The role of RNG as one means to support the transition to a low-carbon economy has been clearly stated by the Ontario government, specifically in the Climate Change Action Plan ("CCAP") and the Long Term Energy Plan ("LTEP"). The Minister of Energy in a letter to the OEB also noted the "economic and environmental benefits that RNG can provide in optimizing the use of existing assets while reducing the province's carbon footprint" that the

[1] OEB's Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap-and-Trade Activities, EB-2015-0363.

integration of RNG into the gas supply portfolios can bring.[2] These economic and environmental benefits include the reduction of GHG emissions through the displacement of conventional natural gas and the capture and prevention of methane releases into the atmosphere. In addition, RNG production uses waste sources in the province, and as such is noted as one of the considerations in the government's Strategy for a Waste-Free Ontario: Building the Circular Economy.

Through the implementation of technology innovations and DSM programs, natural gas heating equipment is reaching very high efficiency levels. Therefore, the decarbonisation of natural gas as a fuel source, through measures like RNG, is a complementary and logical accompaniment to continued conservation and energy efficiency efforts.

b) Union has a long history or working with producers of natural gas to either purchase their local production or provide a regulated service (M13) to transport the producer's gas to Dawn for resale to third parties. Ontario's Cap-and-Trade program has created a renewed interest in RNG as an alternative, local production supply source that can also help lower the GHG emissions intensity of the natural gas Union distributes to its customers.

To this end, Union has been actively working to understand the scale and scope of the potential role of RNG in Ontario. For example Union actively participated in the working group that developed the Marginal Abatement Cost Curve ("MACC"). Union has participated and worked with the Canadian BioGas Association to become more informed about the processes, technologies and potential sources of RNG. Union has also had discussions with potential producers within its franchise area to gauge the interest in producing RNG. These discussions have focused on RNG production potential and understanding when a facility could be in service and producing RNG.

Proponents of several potential RNG projects have approached Union to discuss the process of connecting to the natural gas grid under a Rate M13 service. The Rate M13 service has been used by local Ontario producers of conventional natural gas and is applicable for connecting an RNG producer to Union's transmission and distribution system.

Union may review its M13 service and its other services to support the market development of RNG in Ontario. Union may also review and evaluate new, developing and commercial technologies to produce RNG. Most RNG project developers that Union has met with have expressed frustration with the economic risks associated with RNG production due to the lack of a reliable market for RNG in Ontario. Projects often need capital investment coupled with a long term off-take agreement with a credit worthy counterparty in order to support a business case and to secure financing at reasonable rates.

Several biogas producers have also approached Union about potentially investing in biogas clean-up facilities. In these interactions they have cited their lack of access to sufficient

[2] See response at Exhibit B.Energy Probe.2 f) Attachment 2, p.2.

capital or experience cleaning and conditioning gas. Union sees investment opportunities in these potential projects as unregulated activities in a competitive marketplace.

For instance, StormFisher Environmental approached Union about an investment for a demonstration project which led Storm Fisher and Union to apply to the Ontario Centers of Excellence grant programme to demonstrate a GHG reduction project by converting food waste into RNG. The demonstration project will enable Union to further develop market understanding about RNG production facilities.

The StormFisher Environmental facility in London, Ontario currently accepts and digests approximately 80,000 tonnes of organics annually to produce biogas which they use to generate 2.85 MW of electricity. Excess biogas produced beyond the required amount to produce electricity is currently flared.

The proposed project at the StormFisher site would have an unregulated affiliate of Union, invest capital to construct and own a biogas upgrading unit that uses the excess biogas to produce pipeline quality RNG for injection into the Union transmission and distribution system under a Union Rate M13 service. StormFisher will continue to produce renewable electricity and the excess biogas would be used for the demonstration. The potential project will be in service prior to January 1, 2020.

Potential affiliate projects that bid into Union's procurement program will follow the competitive process applicable to any RNG producer and if successful would be subject to operating within the standards set out within the OEB's Affiliate Relationship Code. No decisions have been made with respect to potential affiliate projects in Union's franchise area that may bid into the program.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit 3 / Tab 4 / p. 24

Preamble: Union Gas indicates that it has been in discussions with landfills, waste water treatment plants, industrial sites, biogas associations seeking to understand the cost of production, the size, the proximity to pipelines required for project viability, and the commercial barriers to market development. Union Gas states: “Through these discussions, Union recognized that the economic potential of RNG can be different than the achievable potential outlined in the 2011 Alberta Innovates study which was used in the development of the MACC.”

Question:

a) Please explain what Union Gas means when it states that the “economic potential” of RNG can be different than the achievable potential outlined in the 2011 Alberta Innovates study.
   i. Please provide the analysis and all supporting documentation that indicates the economic potential of RNG could be different from the 2011 Alberta Innovates study.

b) Please explain whether, and if so how, a different “economic potential” from that outlined in the 2011 Alberta Innovates study could impact:
   i. The market price of RNG
   ii. The price of RNG Union Gas expects to pay in any contract with an RNG supplier
   iii. The RNG funding that will be supplied by the provincial government
   iv. The ratepayers

Response:

a) Economic Potential refers to the concept that projects that can recover an appropriate risk adjusted return for the capital invested will be pursued and developed. The return is a function of the cost of capital, the volume produced and the cost of financing as compared to alternative projects. Achievable potential outlined in the Alberta Innovates Study of 2011 did not exclude projects or volumes on the basis of the relative cost to produce RNG. Economic Potential is highly dependent upon the circumstances of each potential project and its relativity to others in the marketplace. Major determinants of project economics include but are not limited to:

   1. Production volume per year (economies of scale are a factor)
      a. Uptime of the facility
      b. Feedstock proximity, availability and quantity
      c. Life or duration of feedstock supply (closed landfills will have a declining gas production curve over time for example, where an industrial anaerobic

digester may have to bid into a competitive market to procure or incent feedstock to the facility, a municipal waste water treatment plant designed to serve a communities' water processing needs from an urban centre might have a very long life)

2. Biogas quality and consistency and the level of cleaning and conditioning needed to make pipeline quality RNG. As an example, assuming similar annual volumes, it would cost more to clean and condition biogas from a landfill into 1 GJ of RNG than it would to clean 1GJ of biogas from a large anaerobic digester because biogas from a landfill has more variability in gas quality and contains oxygen and nitrogen which are both difficult and costly to remove from the biogas.
3. Technology deployed for biogas clean up (advances in technology will impact competitiveness of older sites in the future)
4. Rate of return required by project investors on any capital deployed
5. Life of the equipment used to produce the biogas
6. Income and costs from feedstock materials
7. Cost of transporting feedstock materials from their source to the plant
8. Cost of separating or preparing feedstock for the process
9. Cost of electrical power to operate the facility and all other Operating and Maintenance costs
10. Impact and duration of any government incentives that may be available to the project or impact the costs of production from the facility
11. Proximity and therefore cost to connect the RNG facility to a natural gas pipeline with sufficient year-round market demand to use the RNG
12. The extent to which required facilities already exist in the biogas production cycle

i. No detailed analysis was undertaken recognizing all of the above factors for every potential project in the province. As a result, this makes it impossible to accurately predict the Economic Potential without relying on many untested assumptions. The current proposal will not generate procurement for volumes near the achievable potential of Ontario.

b) i) and ii) Union expects respondents to the RFP for RNG supply to have factored in the specifics of their respective situations that will impact economics and price using the variables outlined in part a).

iii. Ontario's Climate Change Action Plan states that the province expects to spend $60-$100M to "provide supports to encourage the use of cleaner, renewable natural gas in industrial, transportation and buildings sectors".[1] Union does not have further insight into how the province will allocate funding to introduce additional renewable natural gas volumes into the province's natural gas supply.

iv. The proposal is designed to impose no material cost impact to ratepayers beyond what customers would bear for conventional natural gas in Ontario's Cap-and-Trade environment.

[1] Action number 6.1 of Ontario's five year Climate Change Action Plan.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Reference: EB-2017-0255 Exhibit 3 Tab 4:

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

Question:

a) Please describe the nature of the facilities that Union proposes to develop, own and operate to accommodate acquiring RNG supplies.

b) Please describe the nature of the facilities that the RNG producer would be responsible to develop, own and operate to accommodate delivering RNG to Union.
[For example, Union may be responsible to extend a pipeline to the RNG production point, and install metering, odourization and quality control equipment, but the facilities required to gather, process and compress the RNG would be the responsibility of the producer.]

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

d) Union relies on firm supplies being delivered into the distribution system to meet its design day requirements. Please discuss the RNG supplier delivery obligations and if RNG supplies will be treated as firm supplies to meet such design day loads, or if the natural gas reference price for RNG should reflect a non-firm supply?

e) Union discusses that RNG will be procured (page 22 of 60) through a RFP process:
   i. Does this suggest that the producers will determine the price of RNG, and if so how will Union decide which supplies to acquire?
   ii. How will Union address the capital and ongoing operating costs to develop the distribution system necessary to connect such RNG sources?

Response:

a) Union will own and operate pipelines and injection stations connecting RNG producers to Union's transmission and distribution system.

b) The example given by APPrO is accurate and is consistent with the arrangements Union has with existing local producers of conventional natural gas contracted under Gas Purchase Agreements as well as Union's M13 service.

c) Each potential RNG production facility location will be reviewed for nearby pipeline flows during low and high demand periods. There are no provisions to guarantee local market demands, so seasonal and intra-day gas consumption flow rates will need to be evaluated on a case-by-case basis.

d) Given the varying sources of RNG supplies, Union will make an assessment on a project by project basis to determine whether the RNG supply source can be relied upon for design day planning purposes. This is similar to how Union factors existing local Ontario production into its design day planning. The natural gas commodity component of the RNG price is based upon a forecast of natural gas prices at Dawn.

e)
   i) Producers will determine the price they bid in response to Union's RFP. Please see the response at Exhibit B.Energy Probe.5 e).
   ii) Please see the responses at Exhibit B.LPMA.17 c) and Exhibit B.OPI.5.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Reference: EB-2017-0255 Exhibit 3 Tab 4:

Preamble: Union is seeking approval to develop a renewable natural gas (RNG) program, whereby Union would enter into long term contracts to acquire RNG. APPrO would like to better understand the quality specifications that Union is proposing for these new supplies.

Question:

a) Has Union developed a comprehensive set of RNG gas quality specifications such as the specifications current used in the Province of Quebec: BNQ 3672-100 - Quality Specifications for Injection into Natural Gas Distribution and Transmission Systems?

b) Please provide a copy of the gas specifications that Union will be using to purchase RNG.

c) Is Union seeking approval of the quality specifications for RNG at this time? If not, please explain.

d) If Union has not developed a comprehensive set of specifications for RNG, please compare Union's existing natural gas quality specifications to BNQ 3672-100.

e) Are there other quality standards for RNG from organizations such as the CSA or ISO? If so, please indicate how Union's standards compare with these other standards.

f) Please confirm that the term 'pipeline quality' does not explicitly address potential RNG components such as:
    i. Heavy Metals,
    ii. Siloxanes,
    iii. Volatile and Semi-Volatile Organic Compounds,
    iv. Halocarbons and Organochlorinated Compounds,
    v. Microbiological organisms, including bacteria and viruses, and
    vi. Other biological, chemical, corrosive or other potential hazards.

g) Please indicate how Union will be addressing potential contaminants in the raw RNG that could be detrimental or hazardous to either customers' equipment or customers' health from such things as:
    i. Heavy Metals,
    ii. Siloxanes,
    iii. Volatile and Semi-Volatile Organic Compounds,
    iv. Halocarbons and Organochlorinated Compounds,
    v. Microbiological organisms, including bacteria and viruses, and

vi. Other biological, chemical, corrosive or other potential hazards.

h) Please indicate how Union will assure that the ongoing quality of RNG will be comparable with traditional natural gas supplies. Please include a description of the testing and other quality assurance protocols that will be used to ensure quality:
   a) During the initial startup period (i.e. from the first day of delivery until the volume of RNG and the quality of RNG has stabilized), and
   b) On a long-term basis after the startup period.

i) The gas industry has relied on Natural Gas Interchangeability Indices (NGII) to ensure the ability to substitute one gaseous fuel for another in a combustion application without materially changing operational safety, efficiency, performance or emissions. Please provide Union's proposed NGII specifications for RNG and the basis for such specifications and compare these specifications to the specifications to traditional natural gas. As a minimum, please include the following:
   i. Minimum and Maximum Wobbe Indices,
   ii. AGA Yellow Tipping Index, and
   iii. Weaver Incomplete Combustion Index

j) How will Union address the situation where RNG is tendered for sale by the producer but does not meet all the gas quality specifications.

Response:

a) – b) Please see the response at Exhibit B.LPMA.6.

c) No. Union's gas quality requirements were last approved by the OEB in EB-2017-0087 (Union's January 2018 Rates). Union's gas quality requirements are included in its M13 GT&Cs.[1] The GT&C's are included as Schedule "A" to the Rate Schedules that the OEB approves with each Rate Order.

d) – j) Union will not accept gas that does not meet gas quality requirements outlined in the M13 General Terms and Conditions. Please see the response at Exhibit B.LPMA.6.

[1] EB-2017-0087 Decision and Interim Rate Order dated January 18, 2018.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Reference**:** EB-2017-0255 Exhibit 3 Tab 4:

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

Question:

a) Please indicate if the provincial funding that is being sought is a one-time up-front payment or if the funding will be obtained annually.
b) Please provide the economic test that will be used to address the long-term cost to develop and operate the incremental facilities to attach RNG. Please include an illustrative example including the incremental capital and operating costs for new facilities.
c) Union notes on page 21 of 60, that the forecasted cost of traditional supplies, will be based on the most recent forecasts that are available. What is the source and term of such long-term gas price forecasts and how will Union address the situation where the term of the forecast may be less than the effective term of the RNG project? Please provide Union's current 10-year traditional gas price forecast.
d) Please discuss how the volume of available RNG will be forecasted over the life of a RNG project.
e) Please confirm that some sources of RNG, such as bio-methane from landfill sources, can decline over time.
f) Please discuss who will bear the volumetric risk associated with RNG sources.
g) Please identify and discuss all the financial risks that existing ratepayers will bear for projects associated with attaching RNG supplies. Please also discuss which customer rate classes are expected to bear these financial risks.
h) Please identify all and any other risks that existing ratepayers will bear for projects associated with attaching RNG supplies. Please also discuss which customer rate classes are expected to bear these other risks.

Response:

a) Please see the response at Exhibit B.Staff.4 c).

b) Please see the responses at Exhibit B.LPMA.17 c) and Exhibit B.OPI.5. Since producers are paying for incremental costs associated with incremental facilities required to attach RNG, no economic test is required. It is expected that producers will factor these costs into their price when responding to the RFP.

c) Union is working jointly with EGD to finalize the exact source of the gas price forecast. The gas price forecast used will cover the entire term of the RNG purchase contract it is applied to. The same forecast source will be used for all RNG purchase contracts. See responses at Exhibit B.SEC.3 and Exhibit B.Energy Probe.6 a).

d) Producers will be asked to submit an estimate of their forecasted volume of production over the life of the contract term as part of their RFP response.

e) Only a landfill that is no longer accepting waste will have a slowly declining landfill gas production curve (1-4% annual decline).

f) Union plans to fully mitigate the volume risk associated with RNG purchases by establishing a fixed volume maximum for which the contracted RNG price applies. This will eliminate the risk of depeleting the government funding made available to Union prior to the end of the contract term. In the event RNG delivered to Union is less than forecasted, Union will contract for additional economic RNG supplies in order to fully utilize the government funding. If Union is unable to procure RNG supplies to replace its expected RNG purchases, it will purchase replacement conventional natural gas supply.

g) Please see the response at Exhibit B.Staff.6).

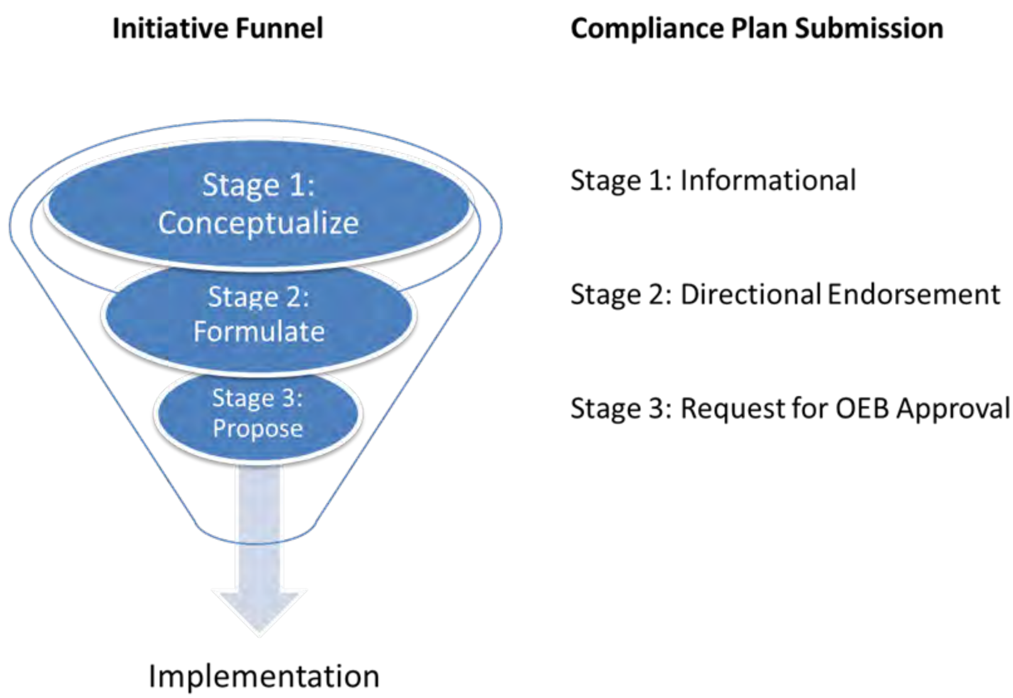
h) Union has not identified any further risks to ratepayers resulting from its proposed RNG procurement program.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: EB-2017-0255, Exhibit 3, Tab 4, Page 9 of 60

Preamble:



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

Response:

The purpose of the initiative funnel is to show the various stages that a new technology or idea will generally follow in its development from idea to a specific initiative and implementation. These types of initiatives can develop over several years, and require an iterative, rather than linear, path through the three stages.

Which initiatives move through the funnel, and at what rate, will be informed by factors such as market signals, policy, the Marginal Abatement Cost Curve, the Long Term Carbon Price Forecast, customer acceptance and technology development. These factors, as well as any others that may impact the development and evaluation of a new idea, are not static; they can be quite dynamic, particularly over a period of years.

Given this context, Union expects that there may be multiple points at which a business case is made to evaluate as to whether an idea, initiative or program continues to move forward; in other words, there may not be just one discrete decision point. For example, analysis may be done to determine if a feasibility study should be completed, or if Union should proceed with a pilot, or if a service or program should be developed. Each of these decisions may require different specific evaluation measures depending on the type of technology and initiative being pursued, and may vary depending on the circumstances or the initiative.

Similarly, this may mean that not all identified potential abatement initiatives will ultimately come to fruition. As initiatives are evaluated and move through the various stages of the funnel, circumstances may change that could impact the appropriateness or applicability of a particular initiative. In cases where a business case evaluation determines to stop a particular initiative, Union will develop and implement an appropriate exit strategy.

Union also notes that the application of the initiative funnel is still in its early stages. As a result, Union continues to develop and refine its established baseline criteria that would be used in evaluating different types of initiatives at the various decision points. However, as described in evidence, criteria include, but are not limited to: technical feasibility, cost, commercial viability, available funding, customer acceptance, and market signals.

As Union re-initiated its development of RNG in late 2015, its development pre-dated the initiative funnel. Please see the responses at Exhibit B.Staff.1 f) and Exhibit B.BOMA.3 for an explanation of how Union evaluated RNG, and why Union is proceeding with an RNG proposal at this time. In addition to market-readiness, public policy in support of RNG as a GHG abatement measure and, available provincial government funding has positioned Union to procure RNG as early as 2018.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: EB-2017-0255, Exhibit 3, Tab 4, Page 17 of 60

Preamble: The government of Ontario and the OEB have clearly and consistently articulated support for the pursuit of renewable natural gas as a component of utility gas supply portfolios. Ontario's CCAP commits funding to RNG, and the 2017 Long-Term Energy Plan, released October 26, 2017, acknowledges RNG as an "innovative Ontario-made source of energy" that can leverage the existing natural gas distribution system.7.

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

Response:

Union is not aware of any cogeneration biogas units providing electricity to the grid in Ontario. There are single cycle biogas based electricity generators in Ontario that have Feed in Tariff ("FIT") or similar type contracts with the OPA/IESO. It is unlikely that facilities with these contracts will choose to stop generating electricity during the term of those contracts due to RNG subsidization. Comparative economics between RNG and electricity generating facilities using biogas are provided the Tables below which were filed in EB-2011-0283 in response to VECC Interrogatory #10 b) (1-15-10):

Results	Project Cost	ROE	Applicable FIT	Converted in
AD scenarios			*$/kWh*	*$/GJ*
Baseline Farm	$ 4,448,919	-	$ 0.1618	$ 18.45
Large Farm	$ 5,751,962	12.2%	$ 0.1486	$ 16.95
Coop Farm	$ 8,200,289	21.3%	$ 0.1486	$ 16.95
SSO (Municipal)	$ 31,524,253	10.1%	$ 0.1486	$ 16.95
Industrial	$ 29,282,343	-	$ 0.1486	$ 16.95
WWTP	$ 2,492,935	7.9%	$ 0.1618	$ 18.45
Landfill scenarios				
Small landfill	$ 5,077,647	9.5%	$ 0.1122	$ 12.80
Medium landfill	$ 9,107,041	23.8%	$ 0.1122	$ 12.80
Large landfill	$ 17,482,106	69.0%	$ 0.1122	$ 12.80

(Where ROE's are negative, no figure is included in the table)

Same scenarios with Genset instead of Upgrading
Capex for major overhaul every 60000 hrs (approximately twice in 20 yrs) of the Genset upfront, connection to electrical grid = connection to gas grid

Results	Project Cost	ROE	OPEX	Electricity	Applicable FIT
AD scenarios			*$/yr*	*kW*	*$/kWh*
Baseline Farm	$ 4,742,621	-	$ 242,239	316	$ 0.1618
Large Farm	$ 4,685,674	4.6%	$ 377,972	647	$ 0.1486
Coop Farm	$ 7,949,528	12.0%	$ 536,346	975	$ 0.1486
SSO (Municipal)	$ 31,147,851	-	$ 2,680,415	1,232	$ 0.1486
Industrial	$ 29,151,657	-	$ 2,760,012	1,584	$ 0.1486
WWTP	$ 1,176,637	64.5%	$ 52,093	225	$ 0.1618
Landfill scenarios					
Small landfill	$ 3,315,119	-	$ 317,780	790	$ 0.1122
Medium landfill	$ 7,686,119	-	$ 740,974	1,846	$ 0.1122
Large landfill	$ 23,141,165	-	$ 2,431,608	6,189	$ 0.1122

(Where ROE's are negative, no figure is included in the table)

At first it appears significantly different from OPA FIT projections but note that:

- Electrigaz model considers gate fee revenues for AD scenarios which are large contributor to ROE.
- It is assumed that the capital cost of electrical grid connection equals capital cost of the natural gas grid connection.

Notes:
FIT converted in $/GJ (no threshold)
*$/kWh * (1kWh/0.0036GJ) * (40% / 95%)*
Percentage represents a systems efficiency average

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: EB-2017-0255, Exhibit 3, Tab 4, Page 23 of 60

Preamble: **Expeditious** (emphasis added) investment in RNG is vital to ensure Ontario's competitiveness, particularly since other jurisdictions may compete with Ontario for these same abatement opportunities. Finally, the development of RNG as an energy source helps to ensure that the significant energy infrastructure that exists for natural gas in Ontario remains used and useful for the long-term.

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

Response:

Union has not delayed action on the Order in Council for 10 years. In fact, Union has been actively pursuing RNG since 2009. Specifically, in 2011 Union and EGD brought forward RNG proposals to the OEB.[1] In its Decision on these proposals the OEB cited a lack of evidence in a number of areas including: concern regarding the proposed 20-year contract term of RNG procurement contracts, and the fact that there was no price of carbon at the time. The OEB invited both Union and EGD to "augment the evidentiary record and to present a revised proposal".[2] Union attributes this lack of evidence to the absence of an established RNG market in North America that could serve as a reference for developing Union's RNG proposal. Union subsequently withdrew its application in 2012.[3]

Since 2012, the RNG and energy landscape in Ontario has changed, with greater focus on policy to reduce GHG emissions. Therefore, in late 2015 Union resumed development of a potential RNG program, recognizing the government's increased focus on climate change initiatives and the announcement of a Cap-and-Trade system to place a price on carbon. In addition, there are established RNG markets in British Columbia, Québec and California for Union to reference.

Until the introduction of Cap-and-Trade there has not been a legislative construct to recognize the carbon abatement opportunity that RNG presents, nor has there been provincial funding to support the introduction of RNG into Ontario's gas supply mix. The acknowledgement and support for RNG by the provincial government was articulated in both the Climate Change

[1] EB-2011-0283 and EB-2011-0242.
[2] EB-2011-0283, Decision and Order, pp.4-5.
[3] EB-2011-0283, Union Letter, September 7, 2012.

Action Plan (June, 2016), and the Long-Term Energy Plan (October, 2017). More specifically, for the natural gas utilities, in December 2016, the MOE requested that the OEB explore RNG as part of utility gas supply portfolios, which it did by incorporating RNG into the Framework for the Assessment of Distributor Gas Supply Plans in March 2017. These developments throughout 2016 and 2017 have encouraged Union's continued interest in RNG. As such, Union has continued to work with Enbridge, stakeholders, and the government to define its RNG program and to secure provincial funding to support it. Provincial funding along with OEB approval of Union's RNG proposal, as requested in this application, is critical to execute the government's policy direction and to advance the adoption of RNG in support of achieving provincial GHG emission targets.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Ex. 3/T4/p. 18

Question:
Why does Union believe it is prudent to pursue RNG procurement in 2018 when it has been determined that it is not a cost-effective measure relative to carbon? If there is no established market in Ontario why is it appropriate to contract for RNG supplies at this time? Why is Union prepared to commit to 10-year contracts?

Response:

Union believes RNG is prudent to pursue since it is a market-ready solution that delivers GHG emissions reductions. As a result Union is proposing a mechanism which utilizes available government funding to hold customers indifferent between the forecast cost of RNG (and related carbon) and the cost of conventional natural gas (including carbon).

Provincial government support for RNG has been articulated in the Ontario Long-Term Energy Plan, which cites the use of RNG as an innovative use of Ontario's natural gas system. [1] In addition, Ontario's Climate Change Action Plan allocates funds specifically for RNG. As a result, the Minister of Energy noted "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", and "encourages the OEB to move forward in a timely manner to include RNG as a potential fuel…as part of the gas utilities' supply portfolios".[2] This recognizes that as the natural gas utilities will be procuring gas supply for the majority of residential customers in the province, they are in the best position to grow this nascent market. Please also see the response at Exhibit B.Staff.1 f).

Union believes that the contract term of 10-years is optimal based on feedback from potential RNG producers, and is required to provide the proper incentive for their investment in RNG projects. Please see the response at Exhibit B.Staff.5.

[1] 2017 LTEP, p. 74.
[2] Letter titled Re: Renewable Natural Gas from the Minister of Energy to Rosemarie LeClair the Chair and Chief Executive Officer of the Ontario Energy Board dated December 16, 2016, p. 2.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Ex. 3/T4

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

Response:

The City of Hamilton at the Woodward Waste Water treatment plant is the only RNG producing facility in Ontario. Union's understanding is this customer has the potential to produce between [redacted].

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Ex. 3/T4

Question:
Is it Union's view that regardless of the economics associated with RNG production, and the absence of a real market, it has a role in terms of developing an Ontario RNG market? Why should Union take on that risk?

Response:

Please see the response at Exhibit B.Staff.9. Union's proposal for RNG does not represent material risk to the Company or ratepayers. See Exhibit B.Staff.6 d) for further discussion on the risks associated with Union's RNG proposal. Union's proposal introduces RNG into the gas supply portfolio in an expedited, market-based approach that will, diversify Union's gas supply portfolio, reduce customer and facility emissions, and is expected to impose no material cost increase beyond what customers would bear for conventional natural gas in Ontario's Cap-and-Trade environment. See Exhibit B.Staff.6 d) for a detailed explanation of cost recovery included in Union's RNG proposal. In addition, RNG project proponents will be paid the contracted fixed price amount for their product, encouraging sustainable growth in a market that is currently in its infancy in Ontario. Expeditious investment in RNG is vital to ensure Ontario's competitiveness, particularly since other jurisdictions may compete with Ontario for these same abatement opportunities. Finally, the development of RNG as an energy source helps to ensure that the significant energy infrastructure that exists for natural gas in Ontario remains used and useful for the long-term.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Ex. 3/T4/p.19

Question:
Union and EGD are proposing an RNG procurement and funding model:

a) Please describe, in detail, the RFP process that Union will be undertaking;

b) Has EGD and or Union determined the contractual arrangements that will be made between EGD, Union and the Province? If so, please provide those details. If not, when are the contractual arrangements expected to be finalized?

Response:

a) Please see the responses at Exhibit B.Staff.4 f) and Exhibit B.Energy Probe.5 e).
b) No, the contractual arrangements have not been determined. It remains unclear if government will choose to utilize this path and therefore it is unknown when arrangements will be finalized. Please see the response at Exhibit B.SEC.4.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Ex. 3/T4/p.19

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

Response:

Union expects that producers will request 10-year contract terms in their RFP responses. However, if producers request terms that are less than 10 years this may result in varying contract terms across different RNG purchases. Varying contract terms does not impact Union's proposed funding mechanism. Please see response at Exhibit B.Staff.5.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Ex. 3/T4/p.19

Question:
Please provide all correspondence, meeting materials, reports and presentations related to Union's collaboration with the Province regarding RNG.

Response:

Please see the responses at Exhibit B.Energy Probe.2 f) and Exhibit B.Energy Probe.5 e).

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Ex. 3/T4/pp. 19-20

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

Response:

Please see the response at Exhibit B.Staff.6 d).

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Ex. 3/T4/p. 22

Question:
What is the expected level of Provincial RNG funding on an annual basis?

Response:

Ontario's Climate Change Action Plan states that the province expects to spend $60-$100 million to "provide support to encourage the use of cleaner, renewable natural gas in industrial, transportation and buildings sectors".[1]

The expected level of funding is subject to ongoing discussions with government.

[1] Action number 6.1 of Ontario's five year Climate Change Action Plan, p. 28, published June 2016.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Ex. 3/T4

Question:
Please identify all of the potential risks for Union's customers regarding its RNG procurement. How will those risks be mitigated?

Response:

Please see the responses at Exhibit B.Staff.6 d) and Exhibit B.APPrO.3.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Ex. 3/T4

Question:
What are the implications for the RNG procurement model if the Ontario Cap and Trade Program is either eliminated or replaced with a carbon tax regime?

Response:

As discussed at Exhibit B.Staff.4 b)-d), Union expects to receive all government funding in advance of entering into agreements with RNG producers. Provided Union has not already contracted for RNG to fully exhaust the government funding made available for the program, Union's proposed RNG procurement model would not change if the Cap-and-Trade program is either eliminated or replaced with a carbon tax regime. Elimination or modification of the price of carbon for Union and its customers, under this scenario, will impact only the forecast price of carbon used at the time of contracting going forward. Please see the response at Exhibit B.Energy Probe.3 b).

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Ex. 3/T4

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

Response:

Because Union and EGD's RNG proposals contemplate purchasing RNG to be delivered into each utilities' respective franchises and systems, Union does not expect it will compete with EGD for RNG supplies.

EGD and Union have requested the OEB's approval to amalgamate effective January 1, 2019 under EB-2017-0306. The companies will continue to operate as separate utilities until the OEB has approved the amalgamation and it has become effective. Throughout 2017, Union and EGD worked together to develop a common RNG procurement model that is not expected to be impacted by the proposed amalgamation.

Union's RNG proposal is responsive to a unique opportunity in the form of government funding which is expected to become available in early 2018.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Ex. 3/T4/p.23

Question:
The evidence states that Union is pursuing commercial opportunities within the Province and will continue to work with RNG project proponents and producers. Please explain what Union is referring to as "pursuing commercial opportunities within the Province."

Response:

Please see the response at Exhibit B.Staff.9 b).

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Reference: Exhibit 3, Tab 4, page 19 of 60

Preamble: At Exhibit 3, Tab 4, page 19, Union states that "Union's RNG plan reflects the requirement of biomass producers to contract for longer-term contracts in order to support capital investment in RNG production facilities. As a result, Union expects to enter into fixed price RNG procurement contracts with terms up to 10 years in duration, subject to provincial funding."

Question:

a) CME wishes to better understand the decision to enter into longer-term fixed contracts. Did Union compare or solicit any third parties to compare the various types and lengths of contracts? If so, please provide them.

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

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

Response:

a) - b) Please see the response at Exhibit B.Staff.5 b).

c) Please see the response at Exhibit B.Staff.6 d).

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Reference: Exhibit C, Tab 5, Schedule 2, Page 8 of 29 (EGD's application)

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

Question:

a) Does Union agree with EGD's description of the state of RNG projects?

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

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

Response:

a) Union takes no position with EGD's description of the state of RNG projects. Union does not have intimate knowledge of potential producers in EGD's territory as the Affiliates Relationship Code treats customer specific information as confidential and prohibits the sharing of confidential information across affiliates. The City of Toronto has made public their intention to generate RNG for their organics processing facilities, and as such, it is reasonable to assume they are at a later stage of development.

b) Union does not expect a project's development stage to drive contract term. The stage of development may be a factor impacting RNG contracts along with many other factors such as the cost of capital, input costs, business risks, forecasted input costs and others. Please see the response at Exhibit B.Staff.10 for a list of factors that can impact RNG price. RFP respondents will include a requested length of term in their tenders. The expected evaluation criteria of tenders are noted in the response at Exhibit B.Energy Probe.5 e).

c) The business case for new facilities or retrofitting existing facilities that produce RNG are expected to require long term contracts to help de-risk capital investments and other business risks. Future contract terms will be dependent on how the RNG industry develops, including the balance between supply and demand. These cannot be predicted and Union will not speculate on the term of contracts in the future. It is possible that after the initial term, the RNG producer may feel comfortable with a second term that is of shorter duration or they may want a longer duration due to the changed business environment at that time.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Reference: Exhibit 3, Tab 4, pages 19 and 20 of 60

Preamble: At Exhibit 3, Tab 4, pages 19 and 20, Union states that "Based on these RNG contracts, Union will then enter into a contractual arrangement with the province to provide provincial funding equal to the difference between the fixed price of RNG contracted with the producer, and the cost of conventional natural gas plus the avoided cost of carbon. The inclusion of the avoided cost of carbon is to recognize that customers would have incurred a carbon cost in the absence of RNG."

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

Question:

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

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

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

Response:

a) - b) Please see Exhibit B.Staff.6 d).

c) The cost associated with the carbon price component of RNG will be treated the same as all other compliance costs and will be allocated proportionately between Union's customer and facility-related compliance obligation.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers & Exporters (“CME”)

Reference: Exhibit 3, Tab 4, page 23 of 60

Preamble: At Exhibit 3, Tab 4, page 23, Union states that “Since Union’s ability to procure RNG is dependent on funding, Union has not included any RNG in its gas supply portfolio for 2018 and has not reflected any related GHG emissions reductions in the 2018 Compliance Plan.”

Question:

a) If Union secures provincial funding, and begins to source RNG, does it plan to begin reflecting GHG emissions reductions in their future compliance plans?

Response:

a) Yes. RNG that is planned to be purchased by Union as part of its proposed RNG procurement program will be incorporated in future compliance plans as an abatement activity.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Ex. 3, Tab 4, pages 17 – 24

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

Response:

Union's RNG program has been designed to keep customers indifferent when compared to the forecasted cost of conventional natural gas in Ontario's Cap-and-Trade environment. As a result, the TRC test is not applicable. Please also see the response at Exhibit B.Staff.1 f).

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Ex. 3, Tab 4, pages 17 – 24

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

Response:

Please see the response at Exhibit B.ED.1.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Ex. 3, Tab 4, pages 17 – 24

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

Response:

Union's RNG proposal does not result in a bill impact to ratepayers. As outlined in Exhibit B.Staff.4 a), Union's RNG proposal uses government funding to ensure that ratepayers are not funding RNG through the Cap-and-Trade program as well as paying for the RNG market premium. Union is proposing to recover a portion of the cost of RNG from ratepayers through gas costs and Cap-and-Trade charges equal to the amounts they would otherwise expect to pay. The balance of the cost for RNG will be paid by government funding. Please see the response at Exhibit B.Staff.6 d).

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Ex. 3, Tab 4, pages 17 – 24

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

Response:

Union will contract for as much RNG as it can given provincial funding available. Please see the response at Exhibit B.Staff.8. Union expects the potential RNG available to be developed will exceed the utilization of the expected $60-$100 million of government funding. Union is unable to determine how much of the government funding will be used each year or by each RNG contract. This information will become available as a result of Union's RFP process.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Ex. 3, Tab 4, pages 17 – 24

Question:
Please estimate the cost per tonne of the greenhouse gas (GHG) emissions reductions (co2e) that the proposed procurement program is expected to achieve via the contracts to be entered into in 2018. Please provide the estimate based on the costs and emission reductions for the lifetime of the contracts (or if that is not possible, please use an illustrative contract year that would be representative of the average costs).
GHG emissions reductions may arise from (a) the displacement of conventional natural gas and (b) the capture of methane that would have been vented to the atmosphere as fugitive emissions.
If the $/tonne estimate includes GHG emissions reductions arising from avoided fugitive methane emissions, please (a) provide the underlying calculations and (b) also provide an estimate that does not include the GHG emissions reductions from avoided fugitive methane emissions.
Presumably the cost per tonne would roughly equal the amount of the proposed subsidy divided by the tonnes of carbon emissions avoided by the RNG in question – if Union uses a different calculation, please explain why, and indicate the magnitude of difference between the two calculation methods.

Response:

The cost per tonne of carbon emission reductions from displacement of conventional natural gas supply is equal to the total incremental cost of RNG over conventional natural gas divided by the carbon emissions avoided by the use of RNG.

Assuming that commodity prices are equal to the amounts shown in Exhibit B.Staff.6, Attachment 1, the average cost per tonne of the carbon emissions reduced over the 10 year term would be approximately $231.07/tonne. Of this amount, $27.30/tonne would be charged to ratepayers in Cap-and-Trade rates (which is expected to be equal to what they would otherwise pay in Cap-and-Trade rates) and $203.77/tonne would come from government funding. This does not include any GHG emissions reductions from fugitive emissions that would be recognized from a potential future offset program in Ontario (see the response at Exhibit B.Staff.3).

Under Union's proposed RNG procurement mechanism, the cost per tonne of carbon emission reductions to Union and its customers will be equal to the OEB's mid-range Long Term Carbon Price Forecast that is available at the time of contracting for RNG supply. In 2018, this cost is equal to $17/tonne.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence (“ED”)

Reference: Ex. 3, Tab 4, pages 17 – 24

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

Response:

Please see the response at Exhibit B.ED.4.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Ex. 3, Tab 4, pages 17 – 24

Question:

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

Response:

a) As of December 31, 2017, the total number of in-franchise customers for Union was 1,474,944.

b) As of December 31, 2017, the total number of residential customers for Union was 1,353,104.

c) Union expects that up to $100 million could be granted by the province for the purposes of Union and EGD's RNG procurement programs. Assuming that half of this amount is available to Union, the government grant per in-franchise customer is $33.90. It is important to note that Union will not be allocating the ratepayer portion of costs associated with RNG purchases across all in-franchise customers. Please see response at Exhibit B.Staff.6 d) for a description of how Union proposes to allocate these costs.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Ex. 3, Tab 4, pages 17 – 24

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

Question:
a) Does Union also have an expectation about the level of provincial funding, and if yes, what is it?
b) How much RNG does Union expect to be able to contract for with the expected level of funding?

Response:

a)-b) Please see the response at Exhibit B.Staff.8.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Ex. 3, Tab 4, pages 17 – 24

Question:

a) Is the RNG procurement program predicated on an expectation that it will spur market change and result in lowering of the price of RNG and improved cost effectiveness over time? Please explain in detail.

b) If Union's proposed program is approved and implemented as planned, what will the forecast impact be on the price and cost-effectiveness of RNG going forward? Please provide a qualitative and narrative response. Please also provide a best efforts quantitative response, including the impact on price and cost-effectiveness going forward to 2030, noting necessary uncertainties and caveats.

c) Please provide an estimate of the investments that would be needed to make RNG cost effective by 2030, noting any uncertainties and caveats.

d) Please estimate the time and investments required to make RNG cost effective.

Response:

a) Please see the responses at Exhibit B.Staff.1 a) and Exhibit B.Staff.1 f).

b) Currently, Union does not have a forecast of Ontario RNG prices. Union will hold a competitive RFP which will establish the market price of RNG over the term of each contract. Union's proposed RNG procurement program, if approved, will make RNG cost effective through the aid of government funding. Absent government funding and given the early stage of the RNG market, Union expects that the cost of RNG will be higher than the combined cost of carbon and the cost of conventional natural gas for the foreseeable future.

c) - d) An estimate of time and investments cannot be estimated as the RNG market in Ontario is in its infancy. The primary purposes of the proposed procurement program are outlined in the response at Exhibit B.ED.11a).

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Ex. 3, Tab 4, pages 17 – 24

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

Response:

Please see the response at Exhibit B.ED.11.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Ex. 3, Tab 4, pages 17 – 24

Question:

a) Please provide a concise list of the high-level objectives of the RNG program.

b) Is Union amendable to providing annual reporting, with concrete metrics, on the success of the proposed procurement project in meeting those objectives?

Response:

a) Union's objectives with respect to its RNG proposal are:

   1) Support the Ontario government Climate Change Action Plan's action area of reducing emissions from fossil-fuel use in buildings;
   2) Develop RNG as an energy source to support a low carbon environment and to help ensure that the significant energy infrastructure that exists for natural gas in Ontario remains used and useful for the long-term;
   3) Encourage sustainable growth in Ontario's RNG market; and
   4) Economically procure RNG as an abatement initiative in Union's Cap-and-Trade compliance plan, such that customers are financially indifferent because the purchase of RNG imposes no material incremental cost beyond what customers would bear for conventional natural gas in Ontario's Cap-and-Trade environment.

b) The cost consequences of the RNG contracts, including the forecast cost of conventional natural gas and the associated avoided carbon cost reflected in the RNG price net of provincial funding, will be provided through existing regulatory mechanisms. These include the QRAM process and, in accordance with the OEB Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Ex. 3, Tab 4, pages 17 – 24

Question:
Please provide Union's best efforts estimate of the RNG potential available for development in Ontario in the medium term (in m3/yr). Please also provide a copy of any reports or studies that include an estimate the available RNG potential, including any reports or studies completed by ICF.

Response:

Please see Attachment 1 for a copy of Electrigaz Report 2011.

Please see Attachment 2 for a copy of Alberta Innovates Report 2011.

Please see the response at Exhibit B.Energy Probe.2 f) (Attachment 8, p.2) together with the following conversion table using a heat value of 37.3 MJ/m^3.

GJ/year	**m^3/year**
60,000	1,608,579
250,000	6,702,413

Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Distribution Grid in Ontario

-Biogas plant costing report

Prepared for:

Enbridge Gas Distribution Inc.

Union Gas Limited

Prepared by:

Electrigaz Technologies Inc.

September 2011

Electrigaz

Executive summary

Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (UGL) are the largest natural gas distribution utilities in Ontario. They are investigating technical and economic challenges of establishing a Renewable Natural Gas (RNG) program that would allow both utilities to provide their customers renewable natural gas. Electrigaz Technologies Inc. (Electrigaz) was hired by EGD and UGL to provide biogas engineering expertise to determine project costing necessary to perform financial modeling and price evaluation for this RNG program.

Current biogas market developments in Ontario and discussions with EGD and UGL enabled Electrigaz to develop nine scenarios that cover a wide range of potential biogas projects with different substrates, biogas flow rates, and biogas quality levels.

Three scenarios use landfill gas (LFG) with various biogas flow rates (small, medium, and large). The remaining six scenarios are anaerobic digestion (AD) processes. Three AD scenarios are from the agricultural sector and one from the industrial sector. Municipal source separated organics (SSO) AD process and a wastewater treatment plant (WWTP) are also evaluated.

In this report, capital and operational costs were estimated for each scenario using the best available Ontario biogas market information. These costs form the basis for an appropriate pricing mechanism which can be found in the *Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Distribution Grid in Ontario—RNG program pricing report.*

Glossary

Biogas	Gas produced from anaerobic digestion, mostly composed of CH_4 and CO_2
Biomethane	Methane extracted from a biogas upgrading system, also called Renewable Natural Gas (RNG)
Digestate	Nutrient rich material left following AD consisting of indigestible material and dead micro-organisms
Renewable Natural Gas	Biomethane interchangeable with natural gas
Substrate	Material uploaded into digesters

Abbreviations and units

AD	Anaerobic digestion
CGA	Canadian Gas Association
CH_4	Methane
CO_2	Carbon dioxide
C:N	Carbon/Nitrogen ratio
CSTR	Complete stirred tank reactor
d	Day
EPC	Engineering, Procurement and Construction
FIT	Feed in tariff
GHG	Greenhouse gases
GJ	Energy unit (Gigajoule)
H_2O	Water
HP injection pressure	High pressure (200 psig)
hr	Time unit (Hour)
H_2S	Hydrogen sulphide
IDC	Interest during construction
IP injection pressure	Intermediate pressure (60 psig)
kg	Mass unit (Kilogram)

kWe	Power unit (Kilowatt electrical)
kWh	Energy unit (Kilowatt-hour)
l	Volume unit (Litre)
LFG	Landfill gas
m^3	Volume unit (Cubic meter)
mg	Mass unit (Milligram)
MJ	Energy unit (MegaJoule)
MSW	Municipal solid waste
%mol	Concentration unit (molar percentage)
N_2	Nitrogen
N/D	Not defined
Nm^3	Volume unit (Normal cubic meter)
O_2	Oxygen
OPA	Ontario Power Authority
OPA FIT	Ontario Power Authority feed in tariff program
ppm	Concentration unit (part per million)
PSA	Pressure swing adsorption
psig	Pressure unit (pound square inch gauge)
RNG	Renewable natural gas
ROE	Return on equity
S	Sulphur
SSO	Source separated organics
t	Mass unit (Tonne)
TS	Total solids
VS	Volatile solids
WWTP	Wastewater treatment plant
XHP injection pressure	Extra high pressure (500 psig)
Yr	Year
ºC	Temperature unit (Celsius degree)

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Charlie Anderson	Air Liquide
Louis Barré	Mabarex

Electrigaz

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1. Introduction

Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (UGL) are the largest natural gas distribution utilities in Ontario. They are investigating technical and economic challenges of establishing a Renewable Natural Gas (RNG) program that would allow both utilities to provide their customers renewable natural gas.

Electrigaz Technologies Inc. (Electrigaz) was hired by EGD and UGL to provide biogas engineering expertise to provide the inputs and scenarios required to determine project costing necessary to perform financial modeling and price evaluation for this RNG program.

Electrigaz is the only engineering firm in Canada specialised exclusively in biogas engineering (Corporate Profile in Appendix 7). Electrigaz differentiates itself by providing complete biogas project development services, including capital and operating cost review, economic projections, price sensitivity analysis, financing and permitting documentation development, contract negotiations (equipment vendors, utilities, GHG, etc.), plant commissioning and operator training services. Over the years, Electrigaz has gained a deep understanding of Ontario's energy and environmental policy framework and how it impacts the development of a viable biogas industry.

1.1 Study objectives

The main objective of the study is to develop plausible biogas plant scenarios and establish their capital and operational cost.

1.2 Methodology

Nine biogas production scenarios were developed to reflect a wide spectrum of potential biogas projects. Capital and operational costs were obtained for each scenario using the best available Ontario biogas market information.

2. RNG production scenarios

Current biogas market developments in Ontario and discussions with EGD and UGL enabled Electrigaz to develop nine scenarios that cover a wide spectrum of potential biogas projects spanning different substrates, biogas flow rates, and biogas quality levels.

Three scenarios use landfill gas (LFG) with various biogas flow rates (small, medium, and large). The remaining six scenarios are AD processes. Three AD scenarios are from the agricultural sector and one from the industrial sector. Municipal source separated organics (SSO) and a wastewater treatment plant (WWTP) AD processes are also evaluated.

2.1 Anaerobic digestion scenarios

Six AD scenarios were developed:

- Baseline agricultural
- Large agricultural
- Agricultural cooperative;
- Source separated organics (SSO);
- Industrial;
- WWTP.

2.1.1 Agricultural scenarios

Farms have access to large amount of contaminant-free organic waste usable for RNG production. Moreover, the possibility of diversifying farm revenues generates significant interest throughout agricultural communities.

For the purpose of this study it is assumed that all three agricultural scenarios are dairy farms that will use manure generated by the farm. Additionally, 25% of substrate used for AD will be off-farm material in the form of grease trap fat. Such assumption is made as this material is readily available, contaminant-free, generates gate fees and has a good biogas yield.

The chosen agricultural scenarios have the following specifications:

Baseline agricultural (350kWe equivalent)
Number of heads (dairy cows): 1,315
Annual manure: 25,000 t
Annual off-farm waste: 8,000 t

Large agricultural (700 kWe equivalent)
Number of heads (dairy cows): 2,615
Annual manure: 49,700 t
Annual off-farm waste: 16,600 t

Agricultural cooperative (1 MWe equivalent)
Number of heads (dairy cows): 3,950
Annual manure: 75,000 t
Annual off-farm waste: 25,000 t

Note that these agricultural scenarios were chosen to reflect technical and economic realities of on-farm RNG production. These RNG projects require capital investment and are unlikely to happen on small singular farms (<1000 heads).

An agricultural cooperative means a centralized digester procuring manure from several farms. In this scenario, transportation cost and regulatory challenges were not analysed.

Biogas production process description

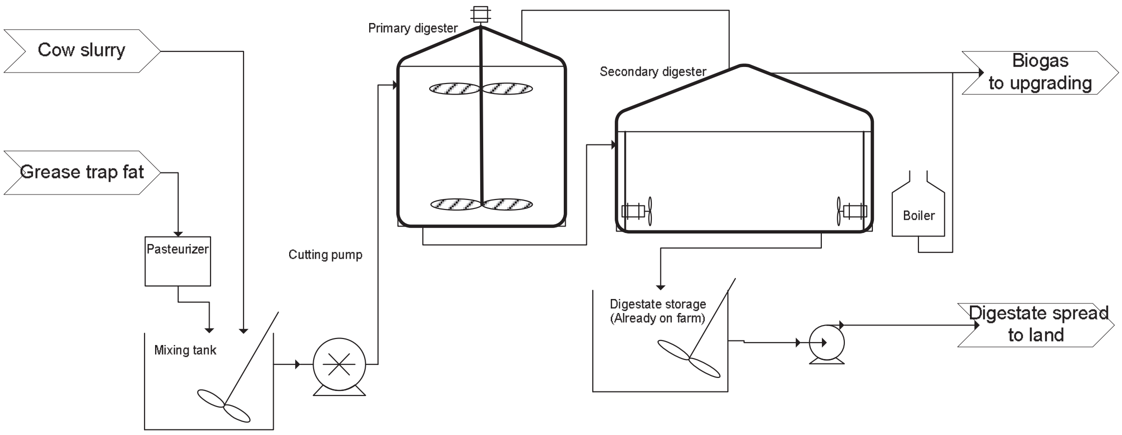

Figure 1. Agricultural AD process schematic

Manure and pasteurized off-farm waste are processed in state-of-the-art proven primary and secondary anaerobic digesters. Digestate generated by the system is assumed to be stored and land spread during allowable season. More process details are available in Appendix 1.

95% of the biogas produced is directed to the upgrading system, the remaining 5% is used to heat the process. Volumes of raw biogas (untreated) sent to the upgrading system for each scenario are as follows:

Baseline agricultural: 150m^3/hr
Large agricultural: 300m^3/hr
Agricultural cooperative: 450m^3/hr

Biogas upgrading and injection

It is assumed that upgraded biogas (RNG) will be injected to IP grid (60 psig), which is a typical pressure for distribution networks. The upgrading system outputs the RNG at the IP injection pressure, which means that no additional compression system is required.

An injection station is installed after the upgrading process for metering, quality control and odorization. An injection pipe connects the injection station to the existing natural gas distribution grid. The injection station and interconnection pipe are operated and maintained by the utilities.

Biogas upgrading mass balance was computed and details are available in Appendix 1. Mass balances were computed assuming a 100% availability of equipment. For the purpose of this study a 95% availability of upgrading equipment was assumed.

Flow rates of RNG to be injected to the grid (considering the availability of the upgrading process) are as follows:

Baseline agricultural: 77m^3/hr
Large agricultural: 158m^3/hr
Agricultural cooperative: 239m^3/hr

2.1.2 SSO scenario

Municipalities consider AD of source separated organics (SSO) as an attractive alternative to reduce the waste sent to landfill.

This scenario assumes that the facility treats 60,000 t of SSO from a 3-stream collection, contaminated with plastic, metal, sand and glass. The scenario is representative of a municipal AD facility serving a large population (300,000+). This scenario could apply to eight municipalities in Ontario [28].

Biogas production process description

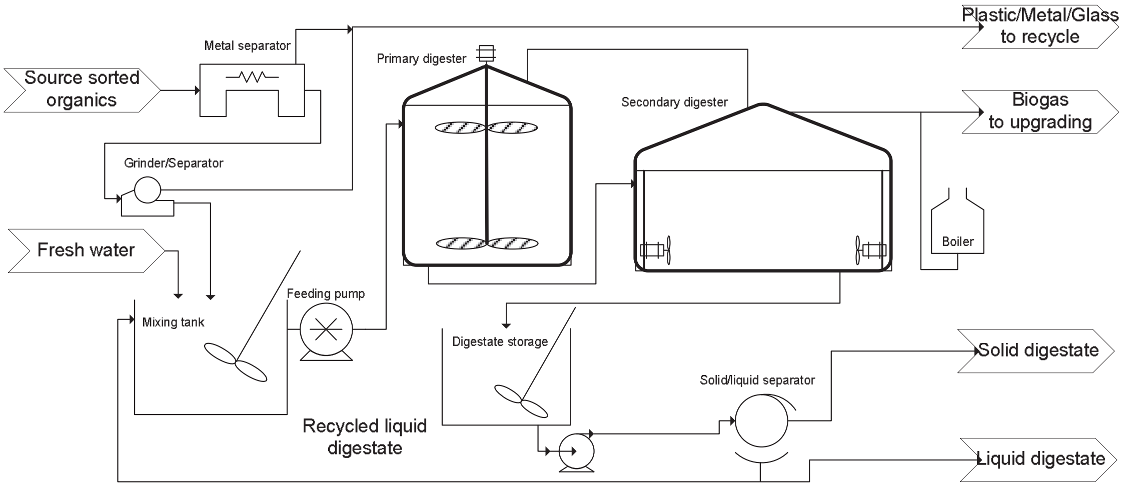

Figure 2. SSO AD process schematic

Reception and pre-treatment processes are required to pre-treat contaminated organics. To avoid odour issues, the reception area includes an airtight building with odour treatment and ventilation units. It is considered that a minimum two-lane reception hall is required to avoid odours generated by trucks waiting. The trucks would dump their loads in reception pits connected to the pre-treatment system.

The pre-treatment process removes contaminants such as plastic, sand, glass and metal, which are assumed to represent 10% of the SSO mass. The contaminants are disposed of in a landfill or recycling facility (disposal fees apply).

The organic fraction of the substrate is processed in state-of-the-art proven primary and secondary AD system. Approximately 700 m^3/hr of raw biogas (untreated) is sent to the upgrading system. This represent 95% of the total amount of biogas produced; the other 5% is used to heat the process.

The digestate is sent to a solid/liquid separation unit. The solid part of digestate is disposed of at a composting facility or sent to a landfill with a disposal cost. The liquid fraction of digestate is sent to an adjacent municipal WWTP also with a disposal cost considered. A small part of liquid digestate is recycled to the mixing tank to bring the substrate into slurry. Note that a total of 47,100 t of digestate (18,900 tonnes of solids and 28,200 tonnes of liquid) must be disposed of per year. More process details are available in Appendix 2

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Biogas upgrading and injection

It is assumed that upgraded biogas (RNG) will be injected to IP grid (60 psig), which is a typical pressure for distribution networks. The upgrading system outputs the RNG at the IP injection pressure which means that no additional compression system is required.

An injection station is installed after the upgrading process for metering, quality control and odorization. An injection pipe connects the injection station to the existing natural gas distribution grid. The injection station and interconnection pipe are operated and maintained by the utilities.

Biogas upgrading mass balance was computed and details are available in Appendix 2. Mass balances were computed assuming a 100% availability of equipment. For the purpose of this study a 95% availability of upgrading equipment was assumed.

It is estimated that the flow of RNG to be injected to the grid is 366 m^3/hr (considering the availability of the upgrading process).

2.1.3 Industrial scenario

Food processing and manufacturing industries such as slaughterhouses, breweries or dairy product manufacturing have organic wastes to dispose of. Instead of sending this waste to landfill, it can be fed to anaerobic digester to produce biogas. The current scenario evaluates the possibility of such projects.

Contaminant-free substrates used for this scenario are 65,500 t/y of fruits and vegetable residues and 65,500 t/y of slaughterhouse waste.

Industrial processors generate large quantity of contaminant-free organic wastes which are suitable for AD.

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Biogas production process description

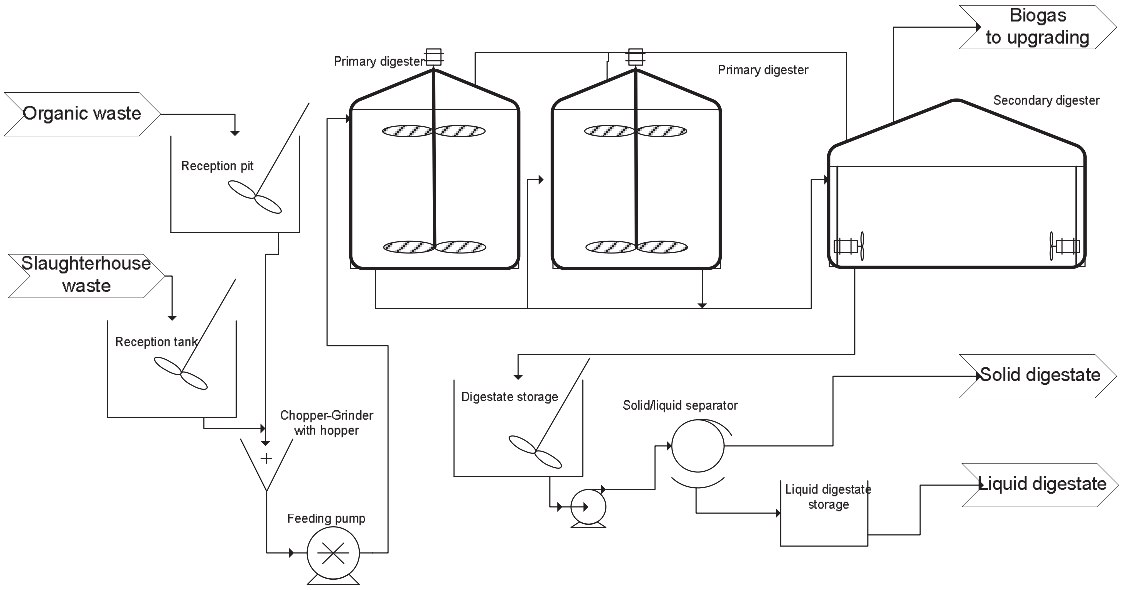

Figure 3. Industrial AD process schematic

The substrate is received in a two-lane reception hall equipped with an odour management system. The organic waste is dumped into a reception pit and the slaughterhouse waste is put into a reception tank.

It is assumed that the substrates used in this scenario are free of contaminants, and no pre-treatment is needed. To ensure that the particle size entering the digesters is homogeneous, the substrate passes through a grinder before it is sent to the digester by a feeding pump.

The organic fraction of the substrate is processed in state-of-the-art multiple tank AD system. Approximately 900 m^3/hr of raw biogas (untreated) is sent to the upgrading system. This represent 95% of the total amount of biogas produced; the other 5% is used to heat the process.

After the digestion process, the digestate is sent to solid/liquid separation unit. The solid part of the digestate is either disposed of at a composting facility or sent to landfill with a disposal cost. The liquid fraction of the digestate must be sent to an adjacent municipal WWTP or to agricultural lands also with a disposal cost. Note that a total of 119,560 t of digestate must be disposed of per year, in which approximately 40,410 t/yr is solid and 79,150 t/yr is liquid. More process details are available in Appendix 3.

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Biogas upgrading and injection

It is assumed that upgraded biogas (RNG) will be injected to IP grid (60 psig), which is a typical pressure for distribution networks. The upgrading system outputs the RNG at the IP injection pressure which means that no additional compression system is required.

An injection station is installed after the upgrading process for metering, quality control and odorization. An injection pipe connects the injection station to the existing natural gas distribution grid. The injection station and interconnection pipe are operated and maintained by the utilities.

Biogas upgrading mass balance was computed and details are available in Appendix 3. Mass balances were computed assuming a 100% availability of equipment. For the purpose of this study a 95% availability of upgrading equipment was assumed.

RNG would be injected into the distribution grid at a flow rate of 471 m^3/hr (considering the availability of the upgrading process).

2.1.4 WWTP scenario

Wastewater treatment plants (WWTP) use AD to reduce effluent sludge quantities and produce biogas. In this scenario, biogas is upgraded and injected into the natural gas distribution grid.

For this scenario, it is assumed that the AD process is already operating and producing biogas. The biogas is considered as untreated and free of charge.

To establish the average WWTP size, data on WWTP using AD process in Ontario was analysed. A WWTP sludge digester was considered with a flow rate of raw biogas (untreated) of 127 m3/hr, equivalent to a 300 kWe biogas plant.

Since it is assumed that the digestion process is already in place, schematic and mass balances have not been prepared for the digestion process of this scenario. However, a mass balance of the upgrading system is presented in Appendix 4.

Biogas upgrading and injection

It is assumed that upgraded biogas (RNG) will be injected to IP grid (60 psig), which is a typical pressure for distribution networks. The upgrading system outputs the RNG at the IP injection pressure which means that no additional compression system is required.

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An injection station is installed after the upgrading process for metering, quality control and odorization. An injection pipe connects the injection station to the existing natural gas distribution grid. The injection station and interconnection pipe are operated and maintained by the utilities.

Biogas upgrading mass balance was computed and details are available in Appendix 4. Mass balances were computed assuming a 100% availability of equipment. For the purpose of this study a 95% availability of upgrading equipment was assumed.

RNG would be injected to the distribution grid at a flow rate of 66.6 m^3/hr (considering the availability of the upgrading process).

2.2 Landfill scenarios

Landfills are uncontrolled anaerobic digesters producing large quantities of low quality biogas from the anaerobic degradation of the organic fraction of municipal solid waste (MSW) buried in them.

To establish representative biogas flow rates, Electrigaz analysed information on the land filling capacity of the 32 largest landfills in Ontario [4]. Other landfills were not taken into consideration because they are considered small. Three landfill scenarios were modeled to represent the complete spectrum of potential biogas flow rates.

These three landfill capacities were used to perform a LandGEM simulation [7] to calculate the annual biogas production. LandGEM simulations predict that biogas production increases each year of landfill operation. Annual capacity and raw biogas (untreated) production of each landfill are as follow:

Small landfill: 60,000 t/yr of MSW producing 475 m^3/hr of biogas
Medium landfill: 140,000 t/yr of MSW producing 1,110 m^3/hr of biogas
Large landfill: 500,000 t/yr of MSW producing 3,960 m^3/hr of biogas

In the small landfill scenario, it is assumed that the RNG will be injected in the IP grid (60 psig), which is a typical pressure for distribution networks. The upgrading system output already brings the biomethane to the IP injection pressure, which means that no additional compression system is required.

In the medium landfill scenario, it is assumed that the RNG will be injected in the HP grid (200 psig). The volume of RNG to be injected is assumed to be too large for local distribution network and interconnection must be performed upstream in the network. Therefore, an additional compression station is needed to bring the biomethane to the required pressure.

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In the large landfill scenario, it is assumed that the RNG will be injected in the XHP grid (500 psig), The volume of RNG to be injected is assumed to be too large for the local distribution network and interconnection must be done in the extra high pressure distribution network. Therefore, an additional compression station is needed to bring the biomethane to the required pressure.

An injection station is installed after the upgrading and compression process for metering, quality control and odorization. An injection pipe connects the injection station to the existing natural gas distribution grid. The injection station and interconnection pipe are operated and maintained by the utilities.

RNG volumes to be injected into the distribution grid are as follow:

Small landfill: 243 m^3/hr
Medium landfill: 569 m^3/hr
Large landfill: 1,896 m^3/hr

Biogas upgrading mass balance was computed and details are available in Appendix 5. Mass balances were computed assuming a 100% availability of equipment. For the purpose of this study a 95% availability of upgrading equipment was assumed.

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3. Economic data

Electrigaz independently collected all economic and technical data and information for this study. Electrigaz estimated AD process capital and operational costs.

To obtain current market information on upgrading systems, quotes from five companies supplying the Canadian market have been requested. These suppliers are as follows:

- Flotech/Greenlane
- Xebec
- Purac
- Haase
- Air Liquide

Only Air Liquide declined to provide budgetary quotes for their system.

In this study no specific biogas upgrading technology is favoured. All quotes received from aforementioned suppliers were used to obtain capital and operational costs of biogas upgrading.

3.1 General assumptions

The study economic and technical battery limits and assumptions were reviewed and approved by EGD and UGL.

Assumptions are supported by Ontario market information or Electrigaz experience. These assumptions were used to create the best snapshot of present Ontario biogas market.

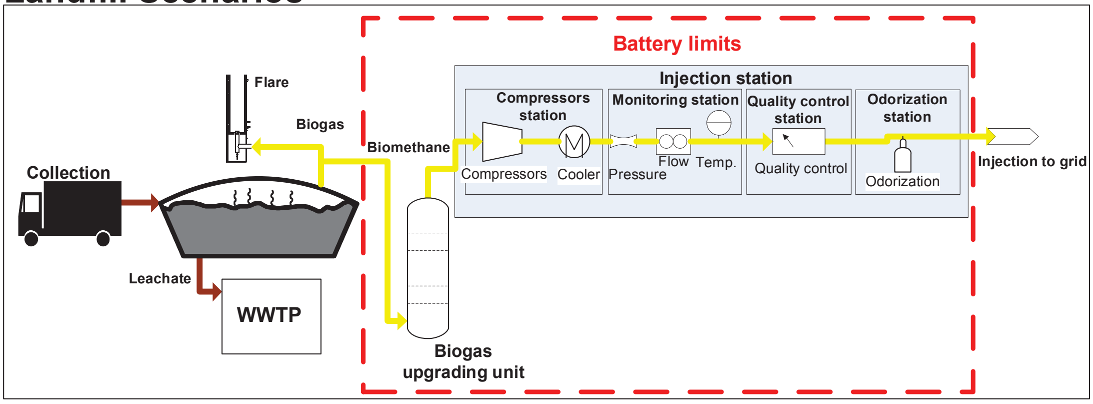
3.1.1 Study battery limits[1]

EGD and UGL have established ownership and responsibility battery limits of RNG production to interconnect to their natural gas distribution grid. The following schematics (Figure 4) represent the battery limits of the study.

According to these limits, the producer is required to pay the utilities capital (aid to construct) for RNG quality monitoring, odorization and injection point (pipe). However, ownership, operation and maintenance of these systems are the responsibility of the utility. Capital and operational costs for the length of pipe to connect to the grid must be absorbed by the producer as well. This will have an impact on the RNG price since these costs will be integrated in the RNG producer economic model.

[1] Battery limits are defined as boundaries of analysis. Technical and economic parameters beyond these boundaries are not taken into consideration in this study.

Landfill Scenarios



AD Scenarios

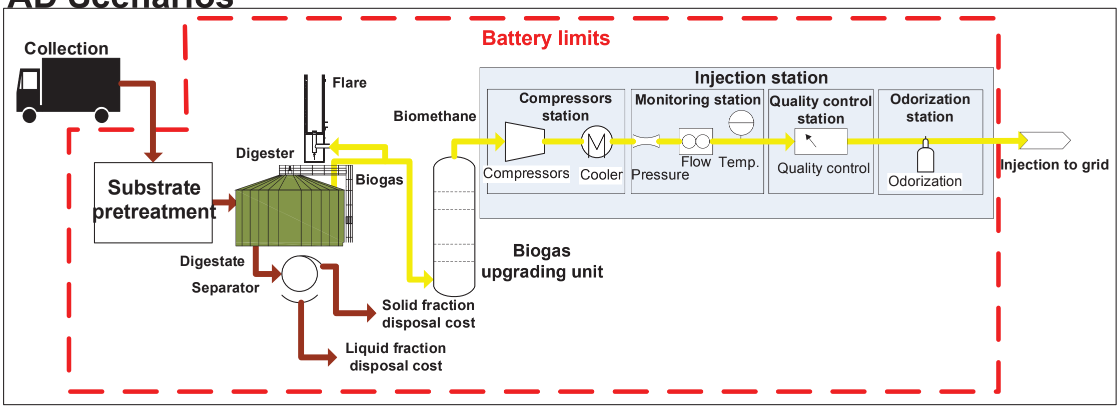


Figure 4: Battery limits of the economic evaluation

The schematics above show the differences between the battery limits of landfill and AD scenarios. For both scenarios, waste collection cost is not considered in this study. Therefore, the purchase and operation of collection trucks and bins are not included in capital or operational costs.

In landfill scenarios, it is assumed that the landfill already exists, collecting biogas and treating leachate. Therefore, no cost or investment is considered for the collection of the biogas and the treatment of the leachate. It is assumed, however, that the project would be developed by a third-party promoter. Therefore, a cost for the supply of the landfill gas is considered as a royalty payment.

In all AD scenarios, except WWTP, the substrate is organic waste brought to the plant, and a gate fee is considered as project revenue.

The WWTP AD scenario differs from other AD scenarios as it is considered that the biogas is already produced and flared. Therefore, it is assumed that the raw biogas is available free of charge.

3.2 RNG specifications

The following RNG specifications (from Union Gas' gas quality requirement for Ontario gas Producers) were used to establish necessary biogas upgrading equipment capital and operational costs.

Table 1: RNG specification requirements considered in this study

Physical Properties	Upper Content Limit	Units
Heating Value (MJ/m3 101.325 kPa, 15C, Dry)	*36.0 to 40.2*	*MJ/M3*
Carbon monoxide	*0.5*	*mol%*
Carbon Dioxide	2	mol%
Oxygen	0.4	mol%
Hydrogen Sulphide	7	mg/M3
Sulpher (in total)	100	mg/M3
Mercaptans or Methyl Mercaptan	5	mg/M3
Water Content	80	mg/M3
Hydrocarbon Dew Point	-10	°C
Gas Interchangeability	YT, flashback, lifting factors range of permiting according to AGA Research bulletin No.36	
Temperature	43	°C
Particulates	shall be commercially free of	
Bacteria	shall be commercially free of	
Hydrogen	Trace	
Ammonia	shall be commercially free of	
Chlorinated & Fluorinated Compounds	shall be commercially free of	
Heavy Metals	shall be commercially free of	
Siloxanes	shall be commercially free of	
Aromatics	shall be commercially free of	
Sand, dust, gums, crude oils, lub. Oils, liquids, chemicals or compounds used in the production, treatment, compression or deshydratation of the gas or any other objectable substance present in sufficient quantity so as to render the Gas toxic, unmerchantable or cause injury to or interference with the Gas pipelines, regulators, meter or other appliances through which it flows, or their operation		

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3.2.1 Macro-economic assumptions

Capital and operational costs for each scenario are calculated and introduced into the economic model as presented in the following chapters. Macro-economic assumptions were set to represent as accurately as possible current Ontario biogas market conditions and establish projects viability.

Some assumptions were informed by the Ontario Power Authority (OPA) feed in tariff (FIT). [9]

The following macro-economic assumptions were used as a basis for all scenarios:

Macro-economic references

- Operating labour salary: $40/hour. [13] [14]
- Electricity price: $110/MWh. [8]
- Process water price: $1.15/m^3.[15] [17] [18] [18]
- Administration costs: 10% of labour costs. [2]
- Plant overhead costs: 15% of total maintenance, supervision and operating labour costs. [2]
- Supervision operation costs: 15% of operating labours costs. [2]
- Marketing costs: 1% of total operational cost. [2]

Macro-economic assumptions

- Maintenance and repair cost: Electrigaz estimated AD system cost from experience; costs of upgrading system are based on quotations obtained from suppliers.
- Operating supplies: Electrigaz estimated AD system cost from experience; costs of upgrading system are based on quotations obtained from suppliers
- Insurance costs: 1.0% of the fixed capital investment.
- Property taxes: 1.0% of the fixed capital investment.
- No revenue on carbon credit sales is considered.

3.3 Anaerobic digestion scenarios assumptions

3.3.1 Agricultural scenarios assumptions

The assumptions for the agricultural scenarios are the following:

Input substrates (Baseline agricultural scenario)

- 25,000 t/yr of cow manure at 8% dry matter
- 8,000 t of grease trap fat free of contaminants at 12% dry matter.
- A gate fee of $35/t is considered only for the grease trap substrate.
- The substrate is considered clean and no pre-treatment is required
- All feedstock is in slurry form.
- Off-farm feedstock is delivered in tanker trucks.

Input substrates (Large agricultural scenario)

- 49,700 t/yr of cow manure at 8% dry matter.
- 16,600 t of grease trap fat free of contaminants at 12% dry matter.
- A gate fee of $35/tonne is considered only for the grease trap substrate.
- The substrate is considered clean and no pre-treatment is required.
- All feedstock is in slurry form.
- Off-farm feedstock is delivered in tanker trucks.

Input substrates (Agricultural cooperative scenario)

- 75,000 t/yr of cow manure at 8% dry matter
- 25,000 t of grease trap fat free of contaminants at 12% dry matter.
- A gate fee of $35/tonne is considered only for the grease trap substrate.
- The substrate is considered clean and no pre-treatment is required.
- All feedstock in is slurry form.
- Off-farm feedstock is delivered in tanker trucks.

General assumptions

- No cost for collection and transport of the substrate is considered.
- No additional land must be bought.
- Construction management approach is used.
- Operating labour hours: 3 hours per day 365 days per year.
- It is considered that the digestate is spread on farm land
- Parasitic electricity of AD process represents 5% of total biogas production.
- The AD system is a CSTR.
- Land owned by farmer, no development costs.
- No secondary containment required.

- Laboratory charges for the RNG quality control are estimated from quotes obtained for this study. It is estimated that one complete gas analysis will be needed every year.
- Laboratory charges for the AD process are equal to 8% of operating labours costs.
- Pressure to injection point is 60 psig. *(Pressure required by UGL and EGD)*

Biogas specifications

- CH_4: 55%
- CO_2: 45%
- H_2S: 1500ppm
- Siloxane: 0 ppm
- H_2O: saturated
- O_2: 0%

3.3.2 SSO scenario assumptions

Here are the assumptions for this specific scenario.

Input substrates

- 60,000 t/yr of SSO from a 3-stream collection, contaminated with plastic, metal, sand and glass.
- Assumed contamination is 10% of mass and must be pre-treated prior to digester feeding. [20]
- 54,000 t/yr of contaminant-free SSO (after pre-treatment) at 25% dry matter, are processed in the digesters.
- A gate fee of $60/t is considered. [21] [22] [23]
- The inflation factor is used on gate fees of the SSO scenario.

General assumptions

- No cost for collection and transport of the substrate is considered. *(It is assumed that the biogas producer is not responsible for substrate collection)*
- Construction approach: full EPC.
- Operating labour hours: 33 hours per day 365 days per year.
- Solid part of digestate must be disposed to landfill or to a composting facility, with a disposal cost of $10/t. [19]
- Liquid part of digestate must be sent to a municipal waste water treatment plant, with a disposal cost of $1.10/t.
- Substrate's contaminant disposal cost: $60/t. [21] [22] [23]
- Parasitic electricity of the AD process represents: 5% of total biogas production.
- The AD system is a CSTR.
- Plant is adjacent to an existing WWTP with adequate land base to add AD process. Minimal site development is required.
- Laboratory charges for the RNG quality control are estimated from quotes; it is assumed that two complete gas analysis will be needed every year
- Laboratory charges for the AD process are equal to 8% of operating labour costs.
- Pressure to injection point is 60 psig. *(Pressure required by UGL and EGD)*

Economic assumptions for the SSO AD scenario differ from the agricultural and industrial scenarios because it is assumed that a municipality will generally disburse less equity for a project and that the interest rate on debt is lower than in the private sector.

It is assumed that the gate fees are higher than in other AD scenarios, since the SSO is contaminated and must be pre-treated. Moreover, it is considered as a waste disposal cost saving for a municipality. No deflation on the gate fees is foreseen; instead, an inflation rate is applied.

Biogas characterisation

- CH_4: 55%
- CO_2: 45%
- H_2S: 1500ppm
- Siloxane: 0 ppm
- H_2O: saturated
- O_2: 0%

3.3.3 Industrial scenario assumptions

The assumptions for this specific scenario are as follows.

Input substrates

- 65,500 t/yr of vegetables residues free of contaminants at 23% dry matter.
- 65,500 t/yr of slaughterhouse waste, free of contaminant, at 10% dry matter.
- Gate fee is $35/t.

General assumptions

- No cost for collection and transport of the substrate is considered.
- Construction approach: full EPC.
- Operating labour hours: 33 hours per day 365 days per year.
- Solid part of digestate must be disposed of at a landfill or a composting facility with a disposal cost of $10/t. [19]
- Liquid part of digestate is sent to a municipal WWTP or to surrounding agricultural lands, with a disposal cost of $3/t.
- The AD system is a CSTR.
- Parasitic electricity of the AD process is 5% of total biogas production.
- Laboratory charges for the RNG quality control are estimated from quotes obtained for this study. It is estimated that two complete gas analyses will be necessary every year.
- Laboratory charges for the AD process are equal to 8% of operating labour cost.
- Pressure to injection point is 60 psig. *(Pressure required by UGL and EGD)*

Biogas characterisation

- CH_4: 55%
- CO_2: 45%
- H_2S: 1500ppm
- Siloxane: 0 ppm
- H_2O: saturated
- O_2: 0%

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3.3.4 WWTP scenario assumptions

Here are the assumptions for this specific scenario.

Input substrate

- No organic waste input.
- Biogas is available but not upgraded.
- Raw biogas is the only input.
- Biogas is free of charge.

General assumptions

- No cost for collection and transport of the substrate is considered.
- Construction approach: full EPC.
- Operating labour hours: 3 hours per day 365 days per year.
- It is assumed that the AD process already exists.
- No cost for digestate disposal is considered since it is an existing operating system.
- Laboratory charges for the RNG quality control are estimated from quotes. It is estimated that two complete gas analyses will be needed every year.
- Pressure to injection point is 60 psig. *(Pressure required by UGL and EGD)*

It is important to note that the economic assumptions for the WWTP scenario are similar to the SSO scenario. This is because it is considered that WWTPs are operated by municipalities. Therefore, the equity/debt ratio and the interest rate on debt are identical to those in the SSO scenario.

Biogas characterisation

- CH_4: 55%
- CO_2: 45%
- H_2S: 250ppm
- Siloxane: 15 ppm
- H_2O: saturated
- O_2: 0%

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3.4 Landfill scenarios assumptions

Economic assumptions are the same in all three landfill scenarios.

It is assumed that the landfill project would be developed by a third party and not by a landfill operator. As a result, it is assumed that the developer would pay a royalty for the landfill gas.

Moreover, since a third party developer is considered, no cost is estimated for operation of the biogas collection system and the treatment of leachate. However, the gas royalty, which act as a raw material cost, should cover these costs.

General landfill assumptions

- Landfill is open for 40 years, while only the 20 median years are taken into account.
- No cost for collection and transport of the waste is considered.
- Construction approach: full EPC.
- Landfill gas royalty: $2/GJ. [23] [24] [25]
- No gate fee is considered for waste input.
- No capital or operational cost for the biogas collection equipment.
- No capital or operational cost is assumed for the treatment of the leachate.
- Operating labour for the biogas upgrading system: 8 hours per day 260 days per year.
- Methane generation constant, k (yr^{-1}): 0.045 [3]
- Potential methane generation capacity, L_0 (m^3/tonne): 83 [5]
- Methane content: 55%.
- Methane collection efficiency: 75% [6]
- Laboratory charges for the RNG quality control are estimated from quotes. It is assumed that three complete gas analyses will be required every year.
- Pressure to injection point *(Pressure required by UGL and EGD)*
    - Small landfill: 60 psig.
    - Medium landfill: 200 psig.
    - Large landfill: 500 psig.

3.4.1 Small and medium landfill assumptions

The biogas characterization for this scenario is as follows:

Biogas characterisation

- Small landfill first year biogas flow rate: 475 m^3/hr
- Medium landfill first year biogas flow rate: 1110m^3/hr
- CH_4: 55%
- CO_2: 40%
- H_2S: 200 ppm
- Siloxane: 18 ppm
- H_2O: saturated
- O_2: 1%
- N_2: 4%

These scenarios assumed optimal gas collection operation to minimize air infiltration.

3.4.2 Large landfill assumptions

The biogas characterization for this scenario is as follows:

Biogas characterisation

- First year biogas flow rate: 3960 m^3/hr
- CH_4: 55%
- CO_2: 40.4%
- H_2S: 200 ppm
- Siloxane: 18 ppm
- H_2O: saturated
- O_2: 0.6%
- N_2: 4%

The large landfill scenario assumed biogas specification differs slightly from other landfill scenarios because such project would require very stringent gas collection operation to minimize air infiltration and cost prohibitive oxygen removal processes.

3.5 Operational costs calculation

Assumptions presented in the previous section and process mass balances of each scenario were used to estimate the operational costs. The costs generated on the first year of the project are presented in the appendices. These costs will change over time due to inflation.

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3.6 Capital costs calculation

Electrigaz used its proprietary biogas production estimating techniques, models, experience and Ontario biogas market information to calculate projects capital cost. Upgrading equipment quotes were obtained from suppliers to estimate capital costs of each scenario. Equipment installation and integration costs were estimated by Electrigaz. A compression station is required only in the medium and large landfill scenarios. These capital costs were evaluated by Electrigaz. All capital cost estimation details and equipment lists are available in project details of Appendix 1 to 5.

The injection station and pipe capital costs were estimated and provided by EGD and UGL. The costs are provided by EGD and UGL and are available in Appendix 6. The following tables shows the total capital costs estimated for every scenario. Four groups of capital costs are presented: AD process, upgrading process, injection, pipe, compression and interest on capital incurred during construction time (IDC).

Table 2. Total capital costs for agricultural scenarios

Scenario name	Baseline Farm	Large Farm	Coop Farm
	IP	IP	IP
AD process	$ 2,252,000	$ 3,055,000	$ 4,579,000
Upgrading process	$ 1,561,000	$ 2,030,000	$ 2,896,000
Injection, pipe, compression	$ 529,930	$ 529,930	$ 529,930
IDC	$ 105,989	$ 137,032	$ 195,359
Total capital costs	$ 4,448,919	$ 5,751,962	$ 8,200,289

Table 3. Total capital costs for SSO, industrial and WWTP scenarios

Scenario name	SSO	Industrial	WWTP
	IP	IP	IP
AD process	$ 26 093 000	$ 23 278 000	$ -
Upgrading process	$ 3 713 000	$ 4 163 000	$ 1 977 000
Injection, pipe, compression	$ 464 930	$ 487 305	$ 464 930
IDC	$ 1 253 323	$ 1 354 038	$ 51 005
Total capital costs	$ 31 524 253	$ 29 282 343	$ 2 492 935

Table 4. Total capital costs for landfill scenarios[2]

Scenario name	Small landfill	Medium landfill	Large landfill
	IP	HP	XHP
AD process	$ -	$ -	$ -
Upgrading process	$ 4 405 000	$ 6 773 000	$ 13 542 492
Injection, pipe, compression	$ 551 680	$ 2 117 080	$ 3 364 205
IDC	$ 120 967	$ 216 961	$ 575 409
Total capital costs	$ 5 077 647	$ 9 107 041	$ 17 482 106

[2] Large landfill capital cost consolidates first year capital cost and inflated year-12 re-investment.

4. Conclusion

Electrigaz used its biogas engineering expertise and best available Ontario biogas market information to obtain each scenario capital and operational cost.

These costs will be used to obtain RNG production cost and to formulate optimal pricing for this RNG program.

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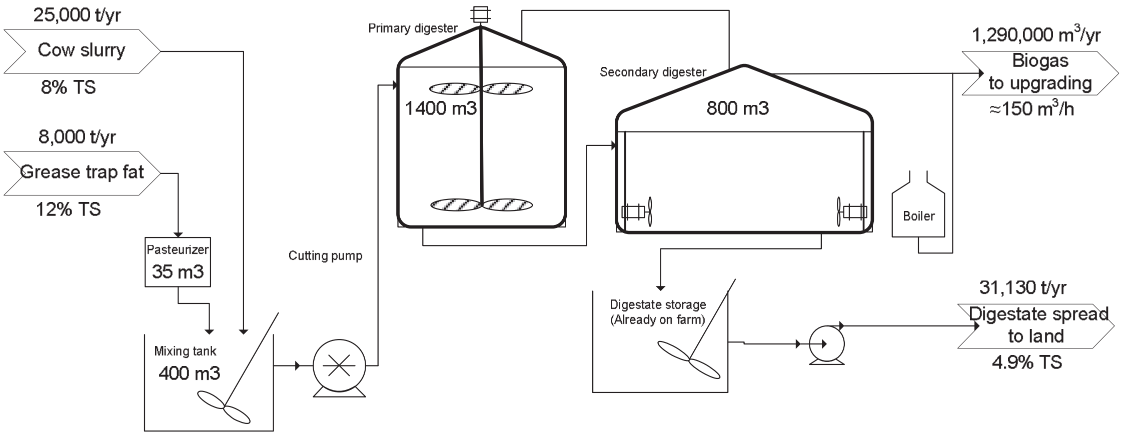
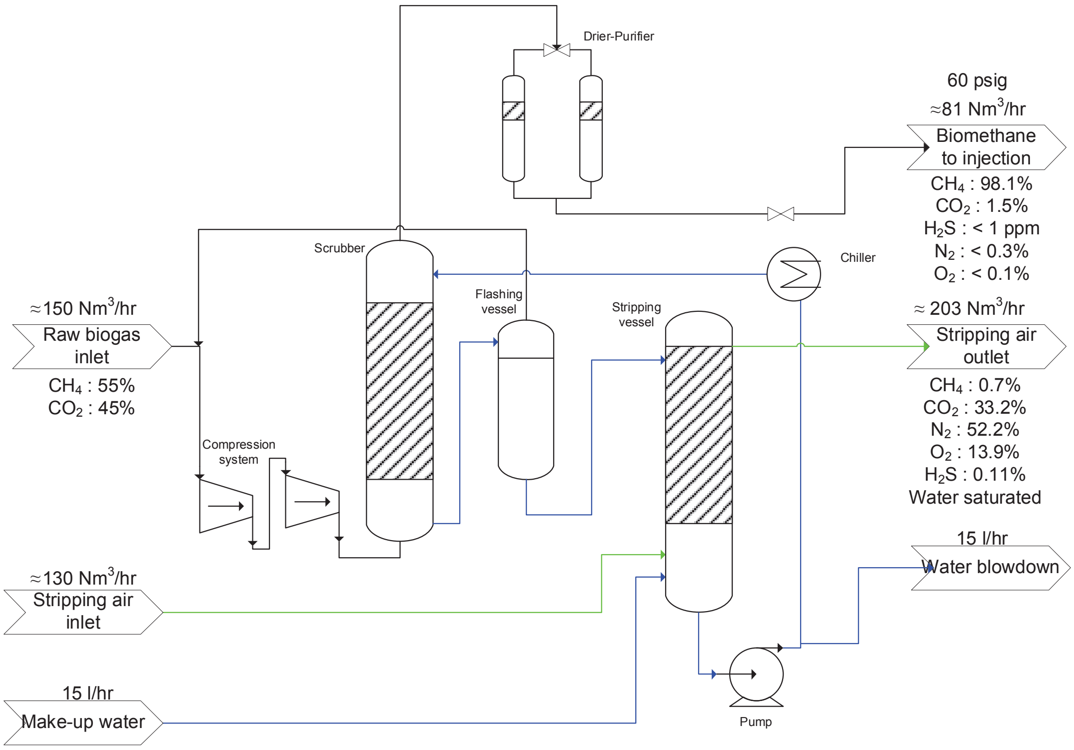
Appendix 1: Agricultural scenario details

Baseline agricultural scenario

Simplified schematic and mass balance of the processes



Simplified schematic and mass balance of the AD unit of the Baseline agricultural scenario



Simplified schematic and mass balance of the Baseline agricultural scenario upgrading unit

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Capital cost details

Capital cost of the AD of the Baseline agricultural scenario

Capital costs (Anaerobic digestion)			
Categories	**Items**		**Total including installation**
Pre-treatment and reception tanks		**$**	**117,000**
	Pasteurizer		
	Mixing tank		
	Mixer (2)		
	Chopper pump		
Anaerobic digestion equipment		**$**	**1,191,000**
	Primary digester tank		
	Top mounted mixer		
	Secondary digester		
	Submersible mixers (2)		
	Double membrane roof (gas storage)		
	Digestate pump		
Heating equipment		**$**	**336,000**
	Heat exchanger		
	Boiler		
	Hot water pump		
Biogas management equipment		**$**	**84,000**
	Flare		
	Gas blower		
Indirect costs		**$**	**273,000**
	Engineering, supervision, project management		
	Legal expenses		
	Start-up, commissioning		
	Temporary services (trailers, utilities, etc.)		
Contractor profit (Construction management approach)		**$**	**90,000**
Contingency		**$**	**161,000**
Total cost		**$**	**2,252,000**

Capital cost of the upgrading unit of the Baseline agricultural scenario

Capital costs (Upgrading)			
Categories	**Items**		**Total including intallation**
Upgrading		**$**	**1,187,000**
	Compressor		
	Scrubber		
	Drying column		
	Stripper		
	Water pump		
	Flashing column		
	Air blower		
	Auxiliaries		
Indirect costs		**$**	**197,000**
	Engineering, supervision, project management		
	Legal expenses		
	Start-up, commissioning		
	Temporary services (trailers, utilities, etc.)		
Construction management fees		**$**	**59,000**
Contingency		**$**	**118,000**
Total cost		**$**	**1,561,000**

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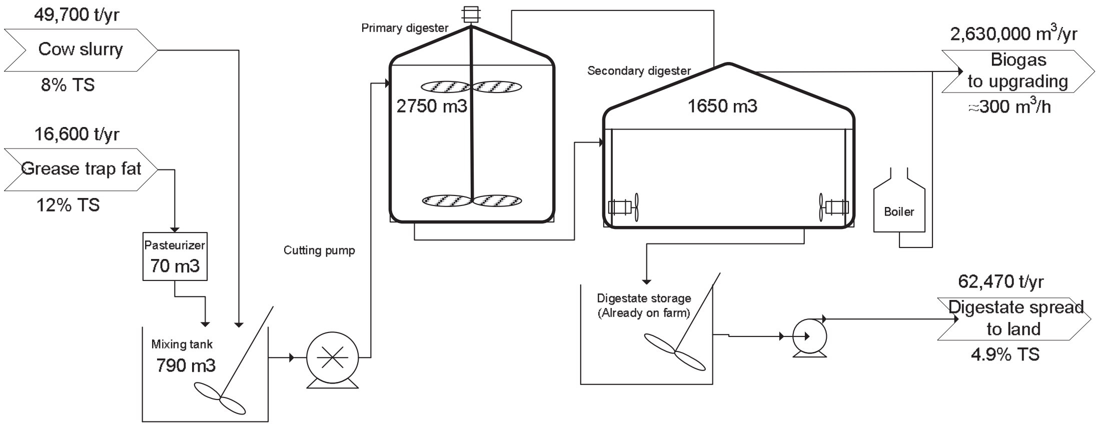
First year operational costs of the baseline agricultural scenario

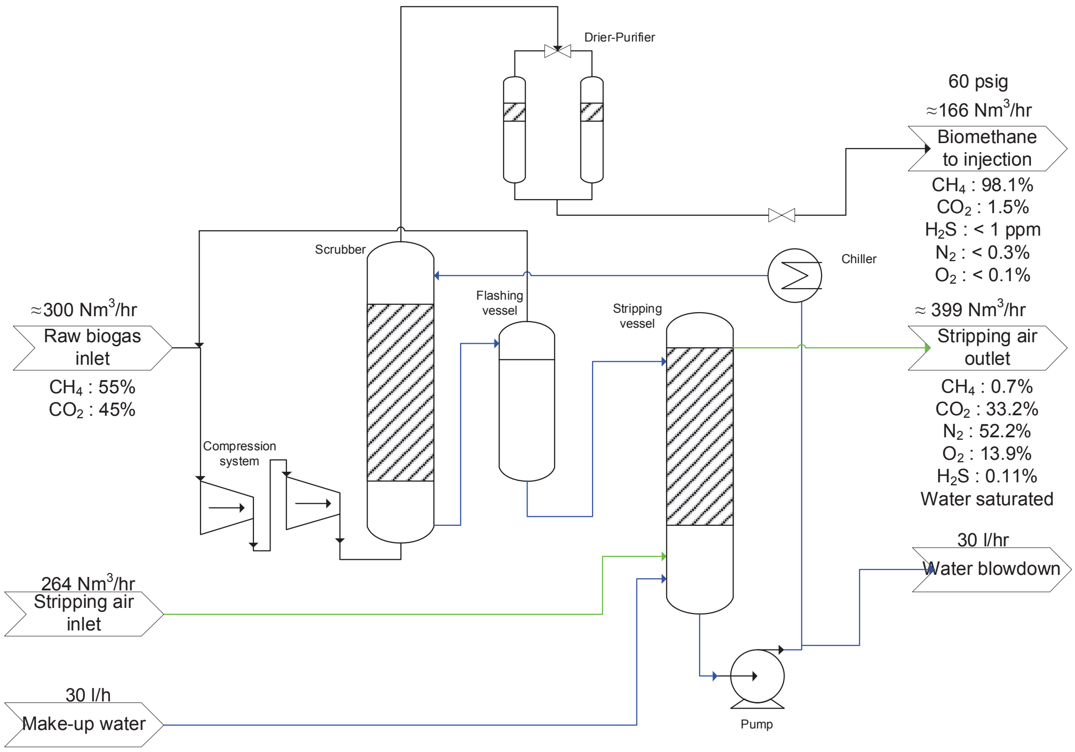
Operational costs		
Operating labor	$	43 800
Operating supervision	$	6 570
Process Water	$	151
Electricity	$	124 874
Waste water disposal cost	$	867
Solid digestate disposal cost	$	-
Contaminant diposal cost	$	-
Injection station O&M	$	5 299
Maintenance and repair	$	36 570
Operating supplies	$	29 523
Laboratory charges	$	7 836
Taxes (property)	$	43 429
Insurance	$	43 429
General expenses	$	21 019
Total operational cost	$	363 368

Large agricultural scenario

Simplified schematic and mass balance of the processes



Simplified schematic and mass balance of the AD unit of the large agricultural scenario



Simplified schematic and mass balance of the large agricultural scenario upgrading unit

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Capital costs details

Capital cost of the AD of the large agricultural scenario

Capital cost (Anaerobic digestion)			
Categories	**Items**		**Total including installation**
Reception and pre-treatment		$	146 000
	Pasteurizer		
	Mixing tank		
	Mixers		
	Feeding pump		
Anaerobic digestion		$	1 683 000
	Primary digester		
	Secondary digester		
	Biogas storage		
Heating system		$	420 000
	Heat exchanger		
	Boiler		
	Hydronic system		
Biogas management		$	100 000
	Flare		
	Gas safety equipment		
	Gas blower		
Indirect costs		$	365 000
	Engineering, supervision, project management		
	Legal expenses		
	Start-up, commissioning		
	Temporary services (trailers, utilities, etc.)		
Construction management fees		$	122 000
Contingency		$	219 000
Total cost		$	3 055 000

Capital cost of the upgrading unit of the large agricultural scenario

Capital cost (Upgrading)			
Categories	**Items**		**Total including installation**
Upgrading		$	1 551 000
	Compressor		
	Scrubber		
	Drying column		
	Stripper		
	Water pump		
	Flashing column		
	Air blower		
	Auxiliaries		
Indirect costs		$	248 000
	Engineering, supervision, project management		
	Legal expenses		
	Start-up, commissioning		
	Temporary services (trailers, utilities, etc.)		
Construction management fees		$	77 000
Contingency		$	154 000
Total cost		$	2 030 000

First year operational costs of the large agricultural scenario

Operational costs		
Operating labor	$	43,800
Operating supervision	$	6,570
Process Water	$	302
Electricity	$	174,121
Waste water disposal cost	$	1,183
Solid digestate disposal cost	$	-
Contaminant diposal cost	$	-
Injection station O&M	$	5,299
Maintenance and repair	$	42,593
Operating supplies	$	34,943
Laboratory charges	$	7,836
Taxes (property)	$	56,149
Insurance	$	56,149
General expenses	$	22,797
Total operational cost	$	451,743

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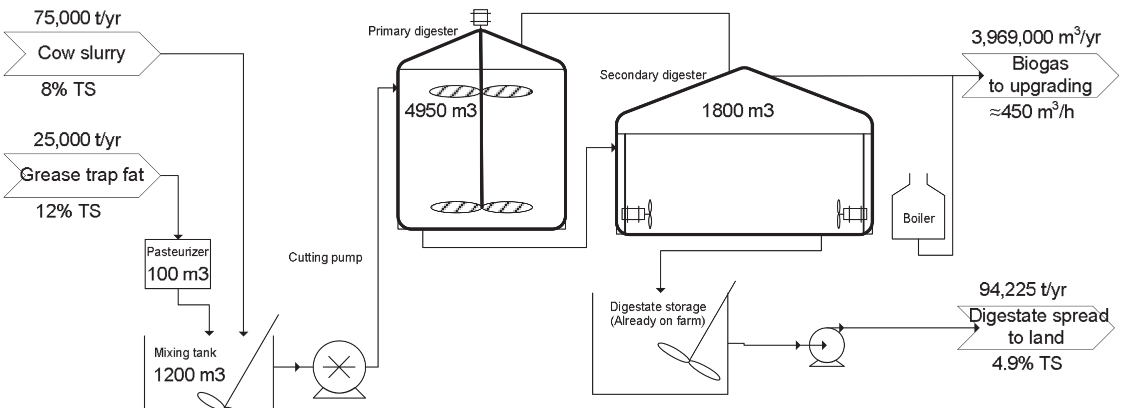
Cooperative agricultural scenario

Simplified schematic and mass balance of the processes



Simplified schematic and mass balance of the AD unit of the Cooperative agricultural scenario

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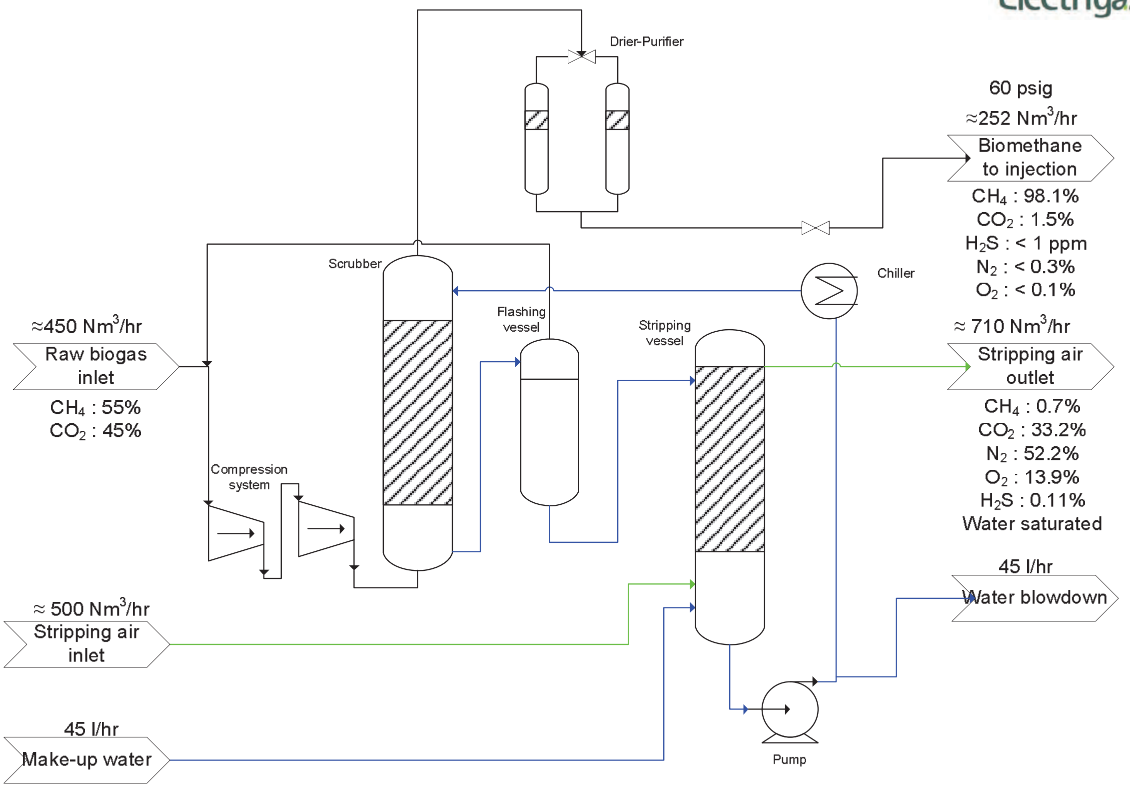

Simplified schematic and mass balance of the Cooperative agricultural scenario upgrading unit

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Capital cost details

Capital cost of the AD of the Cooperative agricultural scenario

Capital costs (Anaerobic digestion)		
Categories	**Items**	**Total including installation**
Pre-treatment and reception tanks		**$ 188,000**
	Pasteurizer	
	Mixing tank	
	Mixer (2)	
	Chopper pump	
Anaerobic digestion equipment		**$ 2,640,000**
	Primary digester tank	
	Top mounted mixer	
	Secondary digester	
	Submersible mixers (2)	
	Double membrane roof (gas storage)	
	Digestate pump	
Heating equipment		**$ 482,000**
	Heat exchanger	
	Boiler	
	Hot water pump	
Biogas management equipment		**$ 128,000**
	Flare	
	Gas blower	
Indirect costs		**$ 575,000**
	Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Contractor profit (Construction management approach)		**$ 202,000**
Contingency		**$ 364,000**
Total cost		**$ 4,579,000**

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Capital cost of the upgrading unit of the Cooperative agricultural scenario

Capital costs (Upgrading)			
Categories	**Items**		**Total including intallation**
Upgrading		**$**	**2,209,000**
	Compressor		
	Scrubber		
	Drying column		
	Stripper		
	Water pump		
	Flashing column		
	Air blower		
	Auxiliaries		
Indirect costs		**$**	**357,000**
	Engineering, supervision, project management		
	Legal expenses		
	Start-up, commissioning		
	Temporary services (trailers, utilities, etc.)		
Construction management fees		**$**	**110,000**
Contingency		**$**	**220,000**
Total cost		**$**	**2,896,000**

First year operational costs of the Cooperative agricultural scenario

Operational costs		
Operating labor	$	43,800
Operating supervision	$	6,570
Process Water	$	453
Electricity	$	222,978
Waste water disposal cost	$	1,577
Solid digestate disposal cost	$	-
Contaminant diposal cost	$	-
Injection station O&M	$	5,299
Maintenance and repair	$	54,023
Operating supplies	$	45,230
Laboratory charges	$	7,836
Taxes (property)	$	80,049
Insurance	$	80,049
General expenses	$	25,718
Total operational cost	$	573,583

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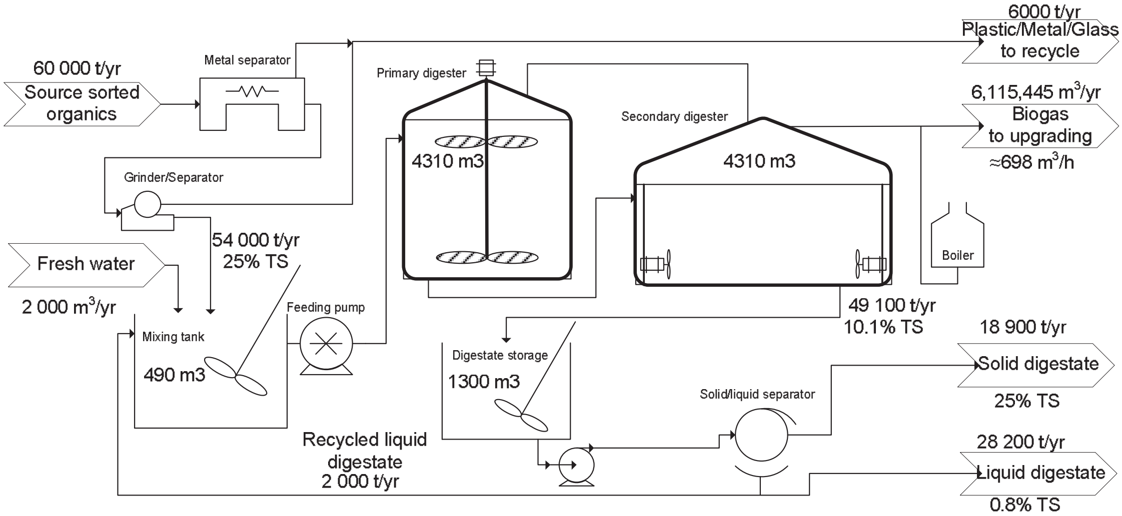
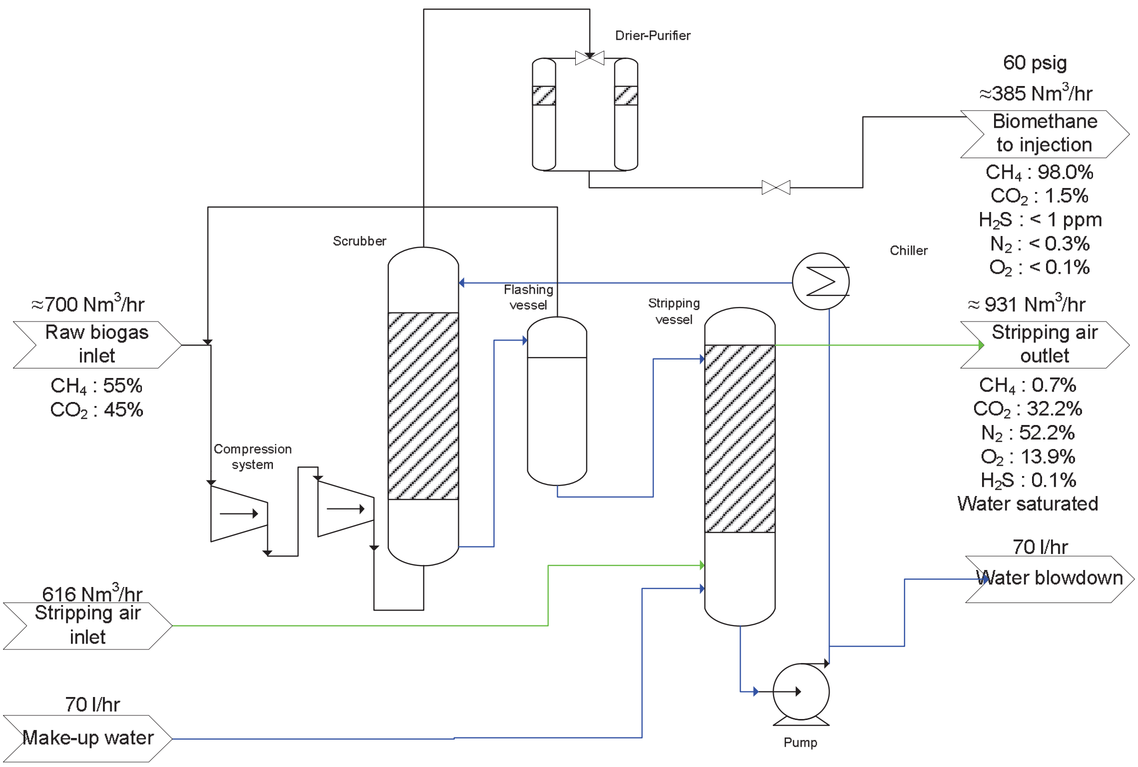
Appendix 2: SSO scenario details

Simplified schematic and mass balance of the processes



Simplified schematic and mass balance of the AD unit of the SSO scenario



Simplified schematic and mass balance of the upgrading unit of the SSO scenario

Capital costs details

Capital cost of the AD unit of the SSO scenario

Capital cost (Anaerobic digestion)			
Categories	**Items**		**Total including installation**
Building and Land		**$**	**3 750 000**
	Reception building		
	Administration building		
	Pump house		
	Digestate management building		
	Land		
Reception and pre-treatment		**$**	**8 242 000**
	Truck scale		
	Reception pits		
	Shredder		
	Conveyors		
	Plastic + metal remover		
	Mixing tank		
	Mixers		
	Feeding pump		
Odour treatment		**$**	**2 203 000**
	Ventillation equipment		
	Acid scrubber + facilities		
	Biofilter + facilities		
Anaerobic digestion		**$**	**2 724 000**
	Primary digesters		
	Secondary digester		
	Biogas storage		
Heating		**$**	**840 000**
	Heat exchanger		
	Boiler		
	Hydronic system		
Digestate management		**$**	**659 000**
	Digestate pump		
	Digestate storage		
	Solid/Liquid separator		
	Solid handling system		
Biogas management		**$**	**389 000**
	Flare		
	Gas safety equipment		
	Gas blower		
Indirect costs		**$**	**2 820 000**
	Engineering, supervision, project management		
	Legal expenses		
	Start-up, commissioning		
	Temporary services (trailers, utilities, etc.)		
Construction management fees		**$**	**2 424 000**
Contingency		**$**	**2 042 000**
Total cost		**$**	**26 093 000**

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Capital cost of the upgrading unit of the SSO scenario

Capital cost (Upgrading)			
Categories	**Items**		**Total including installation**
Upgrading		**$**	**2 732 000**
	Compressor		
	Scrubber		
	Drying column		
	Stripper		
	Water pump		
	Flashing column		
	Air blower		
	Thermal oxidizer		
	Auxiliaries		
Indirect costs		**$**	**429 000**
	Engineering, supervision, project management		
	Legal expenses		
	Start-up, commissioning		
	Temporary services (trailers, utilities, etc.)		
Construction management fees		**$**	**276 000**
Contingency		**$**	**276 000**
Total cost		**$**	**3 713 000**

First year operational costs of the SSO scenario

Operational costs		
Operating labor	$	481,800
Operating supervision	$	72,270
Process Water	$	3,005
Electricity	$	369,526
Waste water disposal cost	$	32,033
Solid digestate disposal cost	$	188,994
Contaminant diposal cost	$	360,000
Injection station O&M	$	4,649
Maintenance and repair	$	215,378
Operating supplies	$	191,200
Laboratory charges	$	48,376
Taxes (property)	$	302,709
Insurance	$	302,709
General expenses	$	190,960
Total operational cost	$	2,763,609

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Appendix 3: Industrial scenario details

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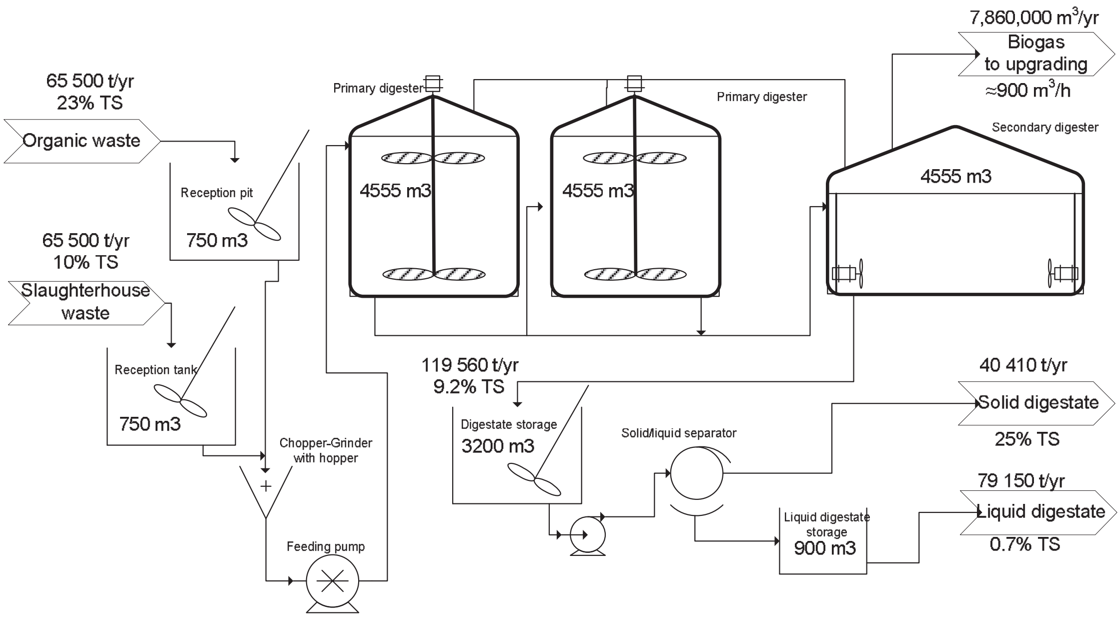
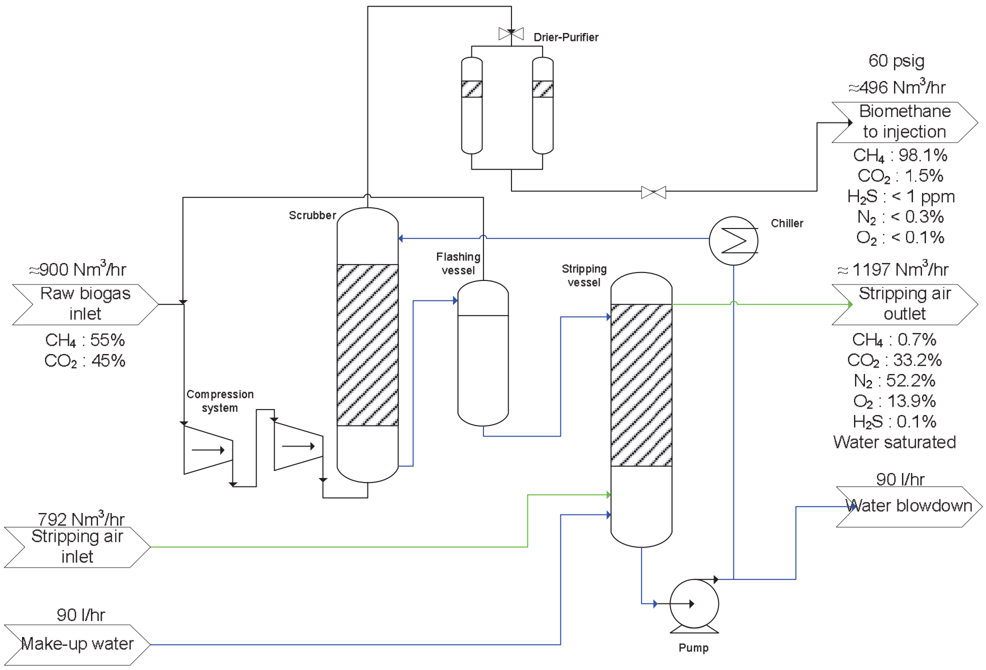
Simplified schematic and mass balance of the processes



Simplified schematic and mass balance of the AD unit of the industrial scenario



Simplified schematic and mass balance of the upgrading unit of the industrial scenario

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Capital cost details

Capital cost of the AD unit of the industrial scenario

Capital cost (Anaerobic digestion)		
Categories	**Items**	**Total including installation**
Building and Land		**$ 4 950 000**
	Reception building	
	Administration building	
	Pump house	
	Digestate management building	
	Land	
Pre-treatment and reception tanks		**$ 1 997 000**
	Truck scale	
	Reception pits	
	Shredder	
	Reception tanks	
	Mixers	
	Feeding pumps	
Odour treatment		**$ 2 377 000**
	Ventillation equipment	
	Acid scrubber + facilities	
	Biofilter + facilities	
Anaerobic digestion		**$ 4 748 000**
	Primary digesters	
	Secondary digester	
	Biogas storage	
Heating		**$ 1 226 000**
	Heat exchanger	
	Boiler	
	Hydronic equipment	
Digestate mangement		**$ 1 253 000**
	Digestate pump	
	Digestate storage	
	Solid/Liquid separator	
	Solid handling equipment	
	Liquid digestate additionnal storage	
Biogas management		**$ 471 000**
	Flare	
	Gas safety equipment	
	Gas blower	
Indirect costs		**$ 2 425 000**
	Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Construction management fees		**$ 2 099 000**
Contingency		**$ 1 732 000**
Total cost		**$ 23 278 000**

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Capital costs of the upgrading unit of the industrial scenario

Capital cost (Upgrading)		
Categories	**Items**	**Total including installation**
Upgrading		**$ 3 175 000**
	Compressor	
	Scrubber	
	Drying column	
	Stripper	
	Flashing column	
	Air blower	
	Thermal oxidizer	
	Auxiliaries	
Indirect costs		**$ 414 000**
	Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Construction management fees		**$ 287 000**
Contingency		**$ 287 000**
Total cost		**$ 4 163 000**

First year operational costs of the industrial scenario

Operational costs	
Operating labor	$ 481,800
Operating supervision	$ 72,270
Process Water	$ 907
Electricity	$ 461,193
Waste water disposal cost	$ 241,005
Solid digestate disposal cost	$ 404,091
Contaminant diposal cost	$ -
Injection station O&M	$ 4,873
Maintenance and repair	$ 195,765
Operating supplies	$ 173,199
Laboratory charges	$ 48,376
Taxes (property)	$ 279,283
Insurance	$ 279,283
General expenses	$ 188,682
Total operational cost	$ 2,830,727

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Appendix 4: WWTP scenario details

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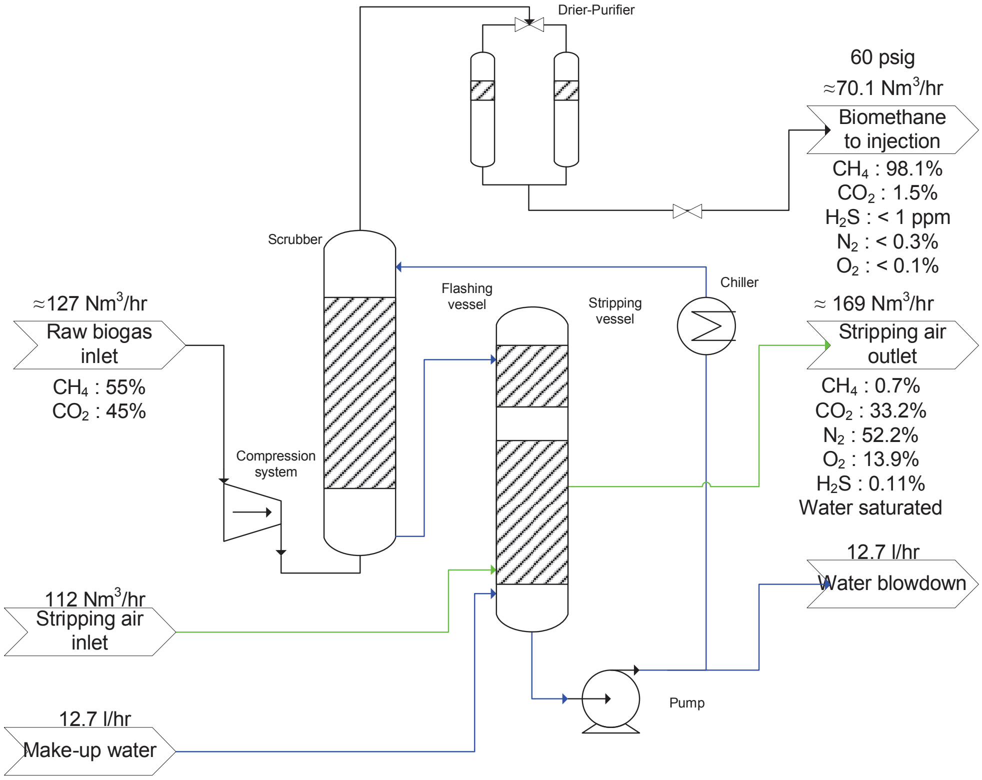
Simplified schematic and mass balance of the processes



Simplified schematic and mass balance of the upgrading unit of the WWTP scenario

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Capital cost details

Capital cost of the upgrading unit of the WWTP scenario

Capital cost (Upgrading)			
Categories	**Items**		**Total including installation**
Upgrading		**$**	**1 593 000**
	Compressor		
	Scrubber		
	Drying column		
	Stripper		
	Water pump		
	Flashing column		
	Thermal oxidizer		
	Air blower		
	Auxiliaries		
Indirect costs		**$**	**176 000**
	Engineering, supervision, project management		
	Legal expenses		
	Start-up, commissioning		
	Temporary services (trailers, utilities, etc.)		
Construction management fees		**$**	**99 000**
Contingency		**$**	**109 000**
Total cost		**$**	**1 977 000**

First year operational costs of the WWTP scenario

Operational costs		
Operating labor	$	43,800
Operating supervision	$	6,570
Process Water	$	128
Electricity	$	38,640
Waste water disposal cost	$	-
Solid digestate disposal cost	$	-
Contaminant diposal cost	$	-
Injection station O&M	$	4,649
Maintenance and repair	$	21,180
Operating supplies	$	5,772
Laboratory charges	$	11,000
Taxes (property)	$	24,419
Insurance	$	24,419
General expenses	$	17,069
Total operational cost	$	197,647

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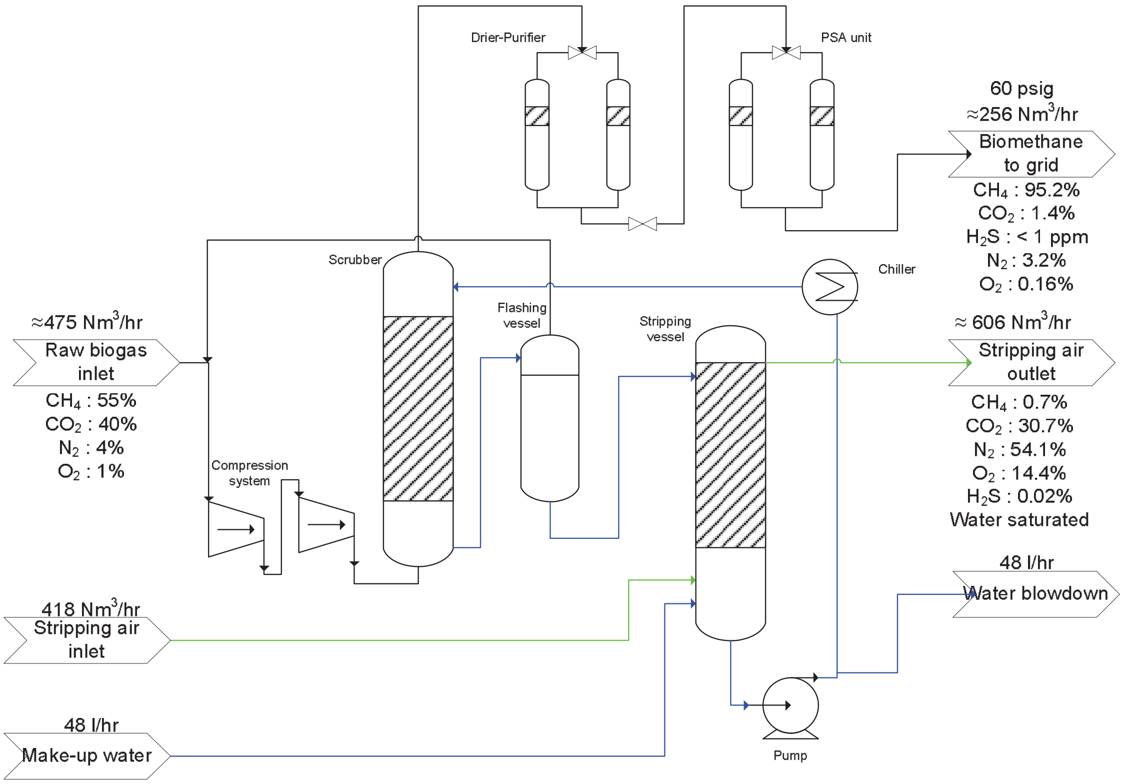
Appendix 5: Landfill scenario details

Small landfill scenario details

Simplified schematic and mass balance of the processes



Simplified schematic and mass balance of the upgrading unit of the small landfill scenario

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Capital costs details

Table Capital cost of the upgrading unit of the small landfill scenario

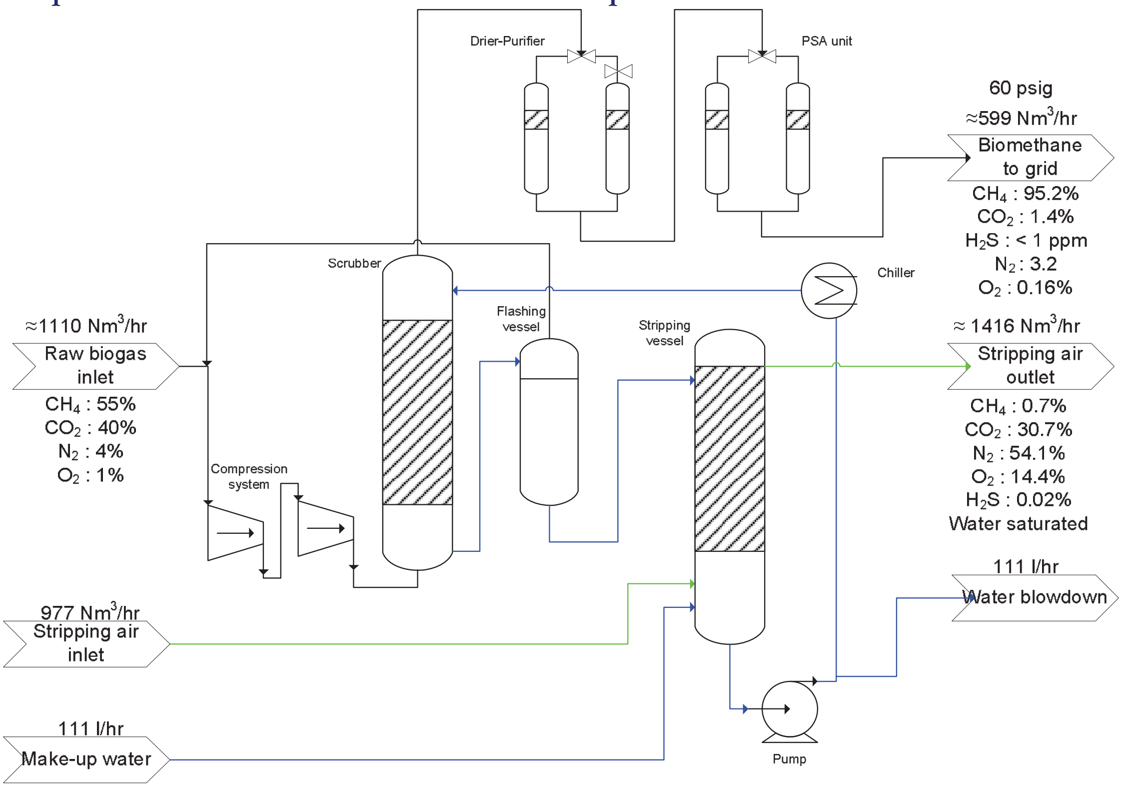
Capital cost (Upgrading)		
Categories	**Items**	**Total including installation**
Upgrading		**$ 3 392 000**
	Compressor	
	Scrubber	
	Drying column	
	Stripper	
	Water pump	
	Flashing column	
	Air blower	
	PSA process (O2/N2 removal)	
	Thermal oxidizer	
	Auxiliaries	
Indirect costs		**$ 421 000**
	Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Construction management fees		**$ 296 000**
Contingency		**$ 296 000**
Total cost		**$ 4 405 000**

First year operational costs of the small landfill scenario

Operational costs	
Operating labor	$ 83,429
Operating supervision	$ 12,514
Process Water	$ 484
Electricity	$ 113,416
Waste water disposal cost	$ 1,892
Landfill gas royalty	$ 161,878
Injection station O&M	$ 5,517
Maintenance and repair	$ 19,680
Operating supplies	$ 15,072
Laboratory charges	$ 16,500
Taxes (property)	$ 49,567
Insurance	$ 49,567
General expenses	$ 31,238
Total product cost	$ 560,753

Medium landfill scenario details

Simplified schematic and mass balance of the processes



Simplified schematic and mass balance of the upgrading unit of the medium landfill scenario

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Capital Cost details

Capital cost of the upgrading unit of the medium landfill scenario

Capital cost (Upgrading)		
Categories	**Items**	**Total including installation**
Upgrading		**$ 5 203 000**
	Compressor Scrubber Drying column Stripper Water pump Flashing column Air blower PSA process (O2/N2 removal) Thermal oxidizer (2) Auxiliaries	
Indirect costs		**$ 672 000**
	Engineering, supervision, project management Legal expenses Start-up, commissioning Temporary services (trailers, utilities, etc.)	
Construction management fees		**$ 449 000**
Contingency		**$ 449 000**
Total cost		**$ 6 773 000**

Capital cost of the HP compression station for the Medium landfill scenario

Capital cost (Compression station HP, Medium landfill scenario)	
Categories	**Total including intallation**
Compressor (110kW)	**$ 664,000**
Indirect costs	**$ 93,000**
Engineering, supervision, project management Legal expenses Start-up, commissioning Temporary services (trailers, utilities, etc.)	
Contractor profit (EPC construction)	**$ 67,000**
Contingency	**$ 67,000**
Total cost	**$ 891,000**

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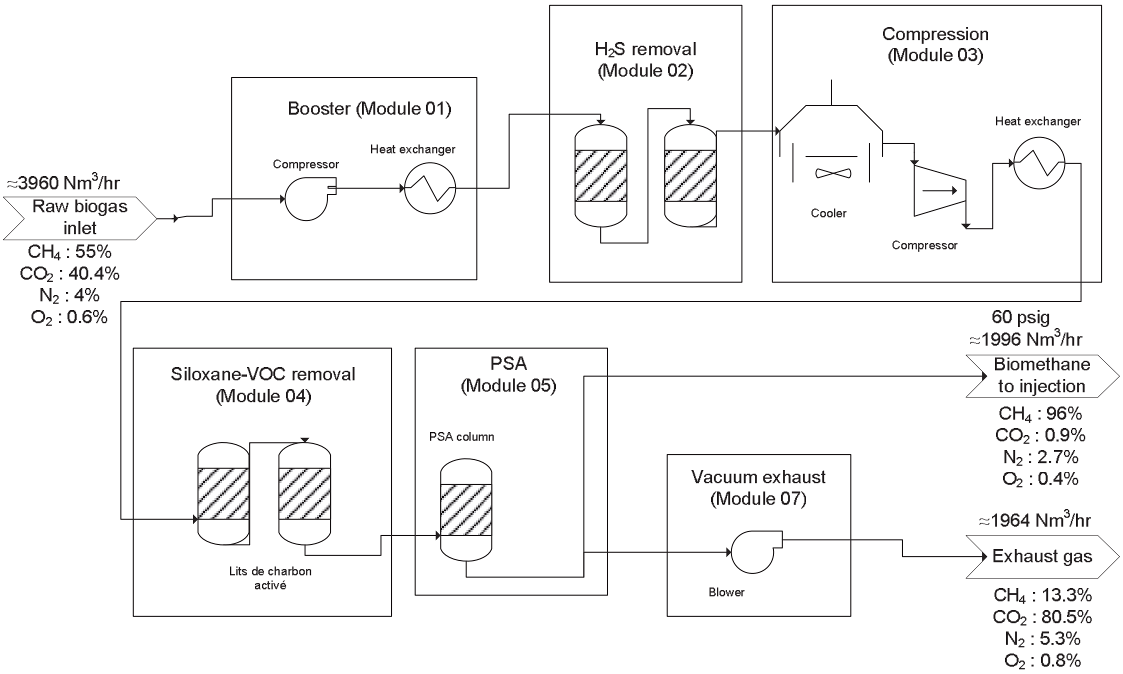
First year operational costs of the medium landfill scenario

Operational costs		
Operating labor	$	83,429
Operating supervision	$	12,514
Process Water	$	1,118
Electricity	$	297,427
Waste water disposal cost	$	4,389
Landfill gas royalty	$	377,716
Injection station O&M	$	12,261
Maintenance and repair	$	24,663
Operating supplies	$	28,386
Laboratory charges	$	16,500
Taxes (property)	$	88,901
Insurance	$	88,901
General expenses	$	37,060
Total product cost	$	1,073,264

Large landfill scenario details

Simplified schematic and mass balance of the processes



Simplified schematic and mass balance of the upgrading unit of the large landfill scenario

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Capital cost details

Capital cost of the upgrading unit of the large landfill scenario

Capital cost (Upgrading)			
Categories	**Items**		**Total including installation**
Module 1: Booster		$	**8 028 000**
	Compressor		
	Heat exchanger		
Module 2: H2S removal			
	Adsorption column		
Module 3: Compression			
	Compressor		
	Cooler		
Module 4: Siloxane/VOC removal			
	Adsorption column		
Module 5: PSA			
	PSA column		
Module 7: Vacuum exhaust			
	Blower		
	Thermal oxidizer (2)		
Indirect costs		$	**895 000**
	Engineering, supervision, project management		
	Legal expenses		
	Start-up, commissioning		
	Temporary services (trailers, utilities, etc.)		
Construction management fees		$	**670 000**
Contingency		$	**670 000**
Total cost		$	**10 263 000**

Capital cost of the XHP compression station for the Large landfill scenario

Capital cost (Compression station HP, Large landfill scenario)		
Categories		**Total including intallation**
Compressor (400kW)	$	**1,550,000**
Indirect costs	$	**217,000**
Engineering, supervision, project management		
Legal expenses		
Start-up, commissioning		
Temporary services (trailers, utilities, etc.)		
Contractor profit (EPC construction)	$	**155,000**
Contingency	$	**155,000**
Total cost	$	**2,077,000**

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Year 12 capital cost of the XHP compression station for the Large landfill scenario

Equipment list Upgrading		
Categories	**Items**	**Total including installation**
Module 1: Booster		$ 1 922 000
	Compressor	
	Heat exchanger	
Module 2: H2S removal		
	Adsorption column	
Module 3: Compression		
	Compressor	
	Cooler	
Module 4: Siloxane/VOC removal		
	Adsorption column	
Module 5: PSA		
	PSA column	
Module 7: Vacuum exhaust		
	Blower	
Indirect costs		$ 273 000
	Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Contractor profit (EPC construction)		$ 158 000
Contingency		$ 158 000
Total cost		$ 2 511 000
Total cost 2024 (inflation included)		$ 3 279 492

First year operational costs of the large landfill scenario

Operational costs		
Operating labor	$	83,429
Operating supervision	$	12,514
Process Water	$	-
Electricity	$	912,223
Waste water disposal cost	$	-
Landfill gas royalty	$	1,270,313
Injection station O&M	$	12,872
Maintenance and repair	$	139,658
Operating supplies	$	125,692
Laboratory charges	$	16,500
Taxes (property)	$	136,272
Insurance	$	136,272
General expenses	$	72,577
Total product cost	$	2,918,321

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Appendix 6: EGD and UGL estimated capital and operational costs of the injection stations

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Capital and operational costs of the injection stations for all scenarios

Capital Cost Summary

Scenario		Enbridge & UGL - Station and Interconnect Costs						
		Station ($)	Pipe ($)	O&M ($/year)	Pipe Length (m)	Pipe Material	Pipe Size (NPS)	Pressure (IP/HP)
1	Aggregated AD	$ 374,305	$ 113,000	$ 4,873	500	Plastic	4	IP
2	Farm AD	$ 351,930	$ 178,000	$ 5,299	1,500	Plastic	4	IP
3	SSO AD	$ 351,930	$ 113,000	$ 4,649	500	Plastic	4	IP
4	WWTP AD	$ 351,930	$ 113,000	$ 4,649	500	Plastic	4	IP
5	Small Landfill	$ 373,680	$ 178,000	$ 5,517	1,500	Plastic	4	IP
6	Medium Landfill	$ 376,080	$ 850,000	$ 12,261	5,000	Steel	8	HP (200 psi)
7	Large Landfill	$ 437,205	$ 850,000	$ 12,872	5,000	Steel	8	XHP (500psi)

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Appendix 7: Corporate profile

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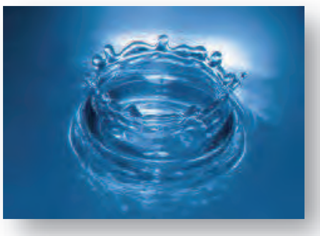

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Biogas Engineering

CORPORATE PROFILE

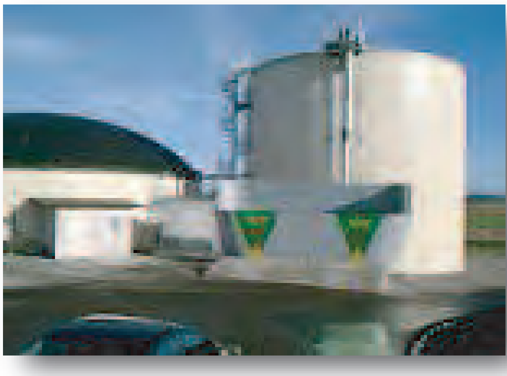
Electrigaz profile

Electrigaz is the only engineering firm in Canada specialized exclusively in biogas engineering. We don't sell equipment; we sell unbiased biogas engineering expertise.

Electrigaz services

Electrigaz differentiates itself by providing complete biogas project development services including:

- Feasibility studies
- Complete biogas plant engineering (construction plans and specifications)
- Anaerobic digestion process design
- Cost assessments and economic projections
- Price sensitivity analysis
- Financial modeling
- Biogas lab testing
- Financial and permitting documentation development
- Project planning
- Contract negotiations (equipment vendors, utilities, GHG, etc.)
- Project management
- Site supervision
- Plant commissioning
- Process optimization



Electrigaz clients

- Agricultural producers
- Industrials
- Energy developers
- Plant builders
- Engineering firms
- Governments
- Municipalities
- Universities, etc.

Electrigaz team

The main strength of Electrigaz is its dynamic and passionate team of professionals dedicated to find solutions to the 21st century energy and environmental challenges.

Eric Camirand, Eng., President

Mr. Camirand holds a degree in Electrical Engineering from McGill University in Montreal. Throughout his junior years Mr. Camirand piloted various engineering projects for corporations such as Petro-Canada, Hong Kong Airport Authorities and Canadian Airlines.

As founder and CEO of Cinax Designs, a Vancouver based video compression software development firm, Mr. Camirand led the company through steady growth that culminated with the merger with Ravisent Technologies of Pennsylvania.

Since then, Mr. Camirand has been active in the renewable energy sector as member of the Quebec caucus for the Canadian Wind Energy Association and more recently as founder-president of the Biogaz Quebec Association. Being an active biogas promoter, Mr. Camirand frequently participates in national and international conferences dedicated to green technologies and bioenergy.

Nathalie Garceau, VP Marketing
Nathalie completed a Bachelor's degree in Civil Engineering at Laval University and a Master's degree in Applied Science at UBC. For several years, Nathalie worked at Sandwell Engineering where she acquired valuable design, project management and site supervision experience. Over the years, Nathalie has pursued her practical education in the fields of agriculture and green marketing.

François Handfield, Jr. Eng., Project Manager
François holds a degree in bio-resources engineering from McGill University in Montreal. With a strong background in farming, François offers down-to-earth practical biogas engineering solutions to biogas engineering challenges.

Raphaël Duquette, Jr. Eng., Project Manager
Raphael holds a degree in chemical engineering from Université de Sherbrooke. Raphael brings to Electrigaz considerable process engineering experience acquired while working for Xstrata Cuivre and Ultramar (refinery).

Natalia Bourenane, MBA, Data analyst
Natalia is a MBA graduate from Université du Québec à Trois-Rivières. In 2010 she joined Electrigaz where she used her expertise in research to develop a methodology of organic waste data collection applicable to every technology of bioenergy production from biomass.

Patrick Simard, Mechanical Engineering Technician
Patrick is a certified mechanical engineering technician bringing hands on solutions to Electrigaz engineering team and clients. Patrick is also an accomplished CAD draftsman.

Liesl Fischer, Jr. Eng., Project Manager
Liesl holds a masters degree in chemical engineering, specialized in environment, from the University of Waterloo. Her master's thesis is about biogas cleaning in biomethanation systems.

Electrigaz partners

Electrigaz and its engineering partners offer over 20 years of applied experience in the field of biogas plant engineering, biogas utilization (heat, electricity, pipeline & vehicles) and general biogas project planning and realization. With over a hundred biogas plants built worldwide our group completely understands the challenges of developing biogas plants in emerging markets.

Krieg & Fischer is an experienced engineering firm specialized in the design and engineering of biogas systems. K&F have designed, built and commissioned hundreds of biogas plants worldwide.
www.kriegfischer.de

BioMil AB is a Swedish engineering company with over 30 years of experience in providing sustainable solutions for the biogas industry. BioMil offers technical consulting services, environmental and economic analyses of biogas and biomethane systems. BioMil cumulates numerous reference projects including a wide range of engineering mandates from preliminary studies and design to construction supervision and project commissioning.
www.biomil.se

Macleod Agronomics provides practical, agri-environmental support for Canadian agricultural development projects. Moreover, the firm offers considerable expertise for the quantification of greenhouse gas reduction projects. While decreasing the overall environment footprint of Canadian agriculture is a major goal for MacLeod Agronomics, a strong focus is also placed on assisting agri-producers and agri-businesses in growing farm-gate revenues with the adoption of sustainable production practices and systems.
www.macleodagronomics.com

Acesa is an infrastucture and energy consulting group based in Rio de Janeiro, Brazil. Acesa is focused on the development of bio-refineries and the energetic applications of biogas in urban and agricultural sectors of the Latin America.
www.acesabioenergia.com

Realizations

2011

> Waste-to-Resources development group (López-Cáceres Eco-Farm), Puerto Rico, USA
Preliminary engineering design report for a co-digestion biogas plant (manure, dairy residues) producing electricity for net metering at the López-Cáceres Eco-Farm.

> Waste-to-Resources development group (Nidco), Puerto Rico, USA
Preliminary engineering design report for a biogas plant producing electricity for a partially off grid quarry and using processed source separated organic residues as feedstock.

> Powerbase, Carleton Place, ON, Canada
Due diligence and troubleshooting of six (6) existing biogas plants.

> Gaz Métro (Project II) Montreal/Riviere-du-Loup, QC
Technical and economic due dilligence of a SSO municipal biogas project in Rivière-du-Loup.

> Stars' Energy Mexico, Baja California Sur, Mexico
Preliminary engineering design and economic analysis for an anaerobic digestion process treating fish processing residues, cheese, and farm waste.

> Innoventé, St-Patrice-de-Beaurivage, QC, Canada
Technical and economic study on integration and operation of an anaerobic digestion plant to a patented composting facility.

> L'Oréal, Montréal, QC, Canada
AD biogas production laboratory testing on pharmaceutical waste.

> Community Energy Partnership Program, Toronto, ON
Analysis and feasibility study for various biogas projects.

2010

> Nouveau-Brunswick Community College, Edmundston, NB, Canada
Design and implementation of a small scale biogas plant for SSO and farm waste.

> BC Ministry of Agriculture, Victoria, BC, Canada
Development and validation of a biomass survey methodology applicable to different bioenergy technologies.

> Earthrenu, Vancouver, BC, Canada, 2009/2011
Feasibility analysis and design of anaerobic digestion plant using 60, 000 t/y of industrial and agricultural organic waste. - $16 millions

> Enfouissement Champlain, Champlain, QC, Canada
Expert witness in the evaluation of the biogas production potential of a landfill.

> Régie Intermunicipale d'élimination de déchets solides de Brome-Missisquoi (R.I.E.D.S.B.M.), QC
Technical and economic due diligence of different anaerobic digestion technologies.

> Municipalité de Chambord, QC, Canada
Technical and economic feasibility study of the anaerobic digestion potential of organic waste for the municipality of Chambord.

> Investeco, Toronto, ON, Canada
Technical and economic due diligence on biogas technologies and business model viability.

> Gaz Métro, Montréal, QC, Canada
Analysis of all potential biomethane projects in Quebec. Recommendation of approach to qualify and answer potential biomethane producer concerns.

Realizations

2009

> Happy Acres, Eastsound, WA
Preliminary design of an anaerobic digestion process for wastewater sludge and grease trap treatment.

> BC Bioenergy Network, Vancouver, BC
Feasibility study – due diligence review: Agricultural waste to green energy and fertilizer project.

> City of Repentigny, QC
Study on the co-digestion of food processing residues of Lebel Island station's methanisers.

> Archibald Dairy Farm, Fredericton, NB
Anaerobic digestion of dairy cattle manure and biosolids for electricity generation at Archibald dairy farm.

> Acton Farms, Fredericton, NB
Anaerobic digestion of beef cattle manure for electricity generation.

> McLeod Agronomics, Fredericton, NB
Study for the development of an ethanol pilot plant using biogas energy in the distillation process.

> Electrigaz (internal project)
Research and development of proprietary online software for preliminary evaluation of biogas projects.
(http://www.electrigaz.com/kefir/index.php)

> Zhang Project, Hebei Province, Chinea
Organic waste survey and analysis for the construction of a centralized biogas plant. On site visit of waste producers and operator. Preliminary design of an anaerobic digestion plant.

2008

> BC Innovation Council, Vancouver, CB
Technical review and economic analysis of biogas upgrading technologies to meet natural gas pipeline specifications.

> Concordia University, Montreal, QC
Preliminary engineering and cost assessment of an anaerobic digester to be located downtown Montreal on the University campus.

> Centre Local de Développement, Repentigny, QC
Conceptual, environmental and economic analysis for the construction of a coop food waste treatment plant where biogas is being reused on site.

Realizations

2007

> HSF Foods (MacLeod Agronomics), Frédéricton, NB
Economic analysis and preliminary engineering of an anaerobic digester for potatoes process industry.

> Fromagerie Champêtre, Repentigny,QC
Technical and economic feasibility study for a lactoserum digester and usage possibility of biogas produced.

> BC Bioproducts Association, Vancouver, CB
Evaluation of the potential for a biogas industry in BC and development of policy recommendations to enable its development in the Fraser Valley.

> Ferme Ashworth, Frédéricton, NB
Preliminary engineering and economic analysis for a farm based anaerobic digester using manure and silage as feedstock.

2006

> BLT Farms, Ste-Catherine, ON
Technical and economic comparative study of anaerobic digestion systems for a poultry producer.

> Frito-Lay, Amérique du Nord
Preliminary evaluation of waste management of potatoes chips plant sludge using anaerobic digestion.

> Mobilogaz, Harrington, QC
Design and construction of a 3 m^3 mobile biogas plant (10kW).

> Ferme Messier, Ham Nord, QC
Technical research to convert heating system " LB White " to use raw biogas.

2005

> Geonomic BT, Bangalore, Inde
Research and development of a waste treatment solution for a southern India temple housing 100 elephants.

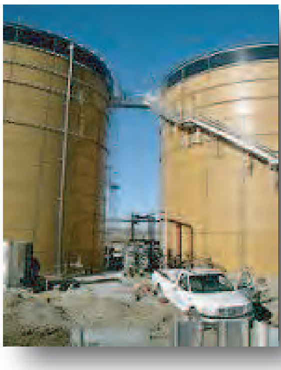
> C3FE Corp, Maine, Etats-Unis
Comparative study of various technologies for treatment of manure for a 4.5 millions chicken egg layers farm.

> Global Advisors Ltd, New Delhi, Inde
Carbon financing study for 7,500 family digesters in rural India.

> Katani Ltd, Tanzanie, Afrique
Research for the implementation of an R & D pilot plant for the production of bio-hydrogen from Sisal fiber plant waste.

Selected biogas plants

FALKENSTEIN Biogas Plant , Germany
Feedstock: corn silage, wheat silage, sweet sorghum
Digester: steel tank 2 x 3,126 m³
Energy: gas engine 2 x 726 kW
Specials: gas holder above secondary digester, thermophilic operation, heat usage
Services provided: design, preplanning, detailed and final construction plans, supervision of construction, start-up



INLAND EMPIRE Biogas Plant, USA
Feedstock: manure, waste
Digester: steel tank, 2 x 4,500 m³
Co-generator: supplied by the gas distribution systems
Specials: biogas feeding into the gas distribution systems
Services provided: detailed final construction plans, tenders, start-up

BIOENERGIE HEHLEN Biogas Plant, Germany
Feedstock: cornsilage
Digester: concrete tank 2,000 m³
Co-generator: gas engine 536 kW
Specials: gas holder above secondary digester, energy recovery heat, thermophilic operation
Services provided: design, preplanning, permission, detailed final construction plans, tenders, supervision of construction, start-up

Mobile Biogas Plant, Quebec, Canada
Feedstock: manure
Digester: fiberglass tank, 2.65 m³
Energy: modified diesel engine 3kW
Specials: mobile pilot plant, can be used to test agricultural, industrial and municipal organic waste
Services provided: design, preplanning, detailed and final construction plans, construction, erection & start-up

Selected biogas plants

SCHORNBUSCHER BIOGAS GMBH Biogas Plant , Germany
Feedstock: corn, organic industrial waste
Digester: concrete tank, 1.500m³
Co-generator: gas engine, 500 kW
Specials: process water recycling, complete pasteurization
Services provided: design, permission, detailed final construction plans, supervision of construction, start-up, operation

WIETZENDORF Biogas Plant / Anaerobic WWTP , Germany
Feedstock: potato starch, potato residues
Digester: 4 steel tanks, 2500 m³ each
Co-generator: gas engine, 4 x 2,1 MW
Specials: protein recovery, reverse osmosis, retention of biomass through decanter
Services provided: planning of complete biological treatment, gas holder, dewatering, safety measuring, controlling devices

Biogas Plant, Saskatoon, Canada
Feedstock: manure, potatoes
Digester: steel tank, 2 000 m³
Co-generator: micro turbine, 4 x 30kW
Specials: gas bag above dual purpose tank
Services provided: design, preplanning, permission planning, detailed and final plannings, supervision of erection, start-up

WIESENAU II Biogas Plant , Germany
Feedstock: cattle manure, dung, wheat, corn silage
Digester: steel tank 4,300 m³
Co-generator: gas engine, 2 x 526 kW
Specials: extension of existing biogas plant
Services provided: design, preplanning, permission, detailed and final construction plans, supervision of construction, start-up

Conferences & Publications

> *Upgrade of organic wastes in food processing industry as energy efficiency measure.*
Annual congress, AQME (Association Québécoise pour la maîtrise de l'énergie) Drummondville, QC, Canada, 2011.

> *Favourable conditions for the development of the biomethane industry in Quebec.*
Americana, Montréal, QC, Canada, 2011.

> *Perspectives of biogas energy in Quebec.*
AQPER (Association québécoise de la production d'énergie renouvelable), Québec, QC, Canada, 2011.

> *Bioenergy feedstock surveying techniques.*
Agri-Energy Forum, Pacific Agriculture Show, Abbotsford, BC, Canada, 2011.

> *Biomethane production cost from various sources.*
Biocycle, Des Moines, IA, USA, 2010.

> *Biogas project development cycle.*
Biogas USA, San Francisco, CA, USA, 2010.

> *Sector future: biogas energy.*
Expo Energie, Montreal, QC, Canada, 2010.

> *Production of biomethane from organic waste.*
Efficacité énergétique. St-Hyacinthe, QC, Canada, 2010.

> *Eastern Canada biogas policy development: myths and reality.*
International Bioenergy Conference, Prince George, BC, Canada, 2010.

> *Panorama of bioenergy solutions.*
Forum Bioénegie, Montreal, QC, Canada, 2010.

> *Electric cars economic analysis as a solution for renewable energy in Quebec.*
Salon TEQ, Quebec, Canada, 2010.

> *Mandatory biomethane mix in the Canadian natural gas network.*
Growing the margins, London, ON, Canada, 2010.

> *Technical and economic challenges of building a mobile biogas plant.*
Biocycle, California, CA, USA, 2009.

> *Economic viability of upgrading farm biogas to sell energy directly to consumers over the natural gas grid.*
Growing the margins, London, ON, Canada, 2008.

> *Prospects of anaerobic digestion potential of organic materiel and biogas energy valorization for various Canadian markets.*
Salon TEQ, Quebec, QC, Canada, 2008.

> *Anaerobic digestion technologies.*
Quebec Liberal Party congress, 2008.

> *Perspectives for biomethane production and resell in the Fraser Valley.*
BC Agricultural show, BC, Canada, 2008.

> *Farm based biogas projects in Ontario.*
Toronto International Agricultural show, ON, Canada, 2008.

> *Biogas investment opportunities.*
Biofinance conference, Toronto, ON, Canada, 2008.

> *On farm energy production.*
Conférence énergie à la ferme, St-Jean-Richelieu, QC, Canada, 2008.

> *Economic viability of upgrading farm biogas for thermal or automotive applications.*
Biocycle conference, WI, USA, 2008.

> *Biogas principles.*
CRAAQ, Methanisation day, QC, Canada, 2007.

> *Climate change and anaerobic digestion.*
APCAS, Air et changements climatiques, Montreal, QC, Canada, 2007.

Electrigaz Clients

Stars Energy Mexico
Earth Renu Energy Corp.
BC Bioproducts
City of Repentigny
Concordia University
Municipality of Chambord
Province of British Columbia
Investeco
Innoventé
CLD de la MRC de l'Assomption
Collège communautaire du Nouveau-Brunswick
L'Oréal
British Columbia Innovation Council
Powerbase energy systems
Gaz Métro
Champêtre Cheesery
Massachusetts Institute of Technology
BC Bioenergy Network
MacLeod Agronomics
Community Energy Partnerships Program
Frito Lay
WTR Development group
R.I.E.D.S.B.M.
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Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Distribution Grid in Ontario

-RNG program pricing report

Prepared by:

Electrigaz Technologies Inc.

In conjunction with:

Enbridge Gas Distribution Inc.

Union Gas Limited

September 2011

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Executive summary

Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (UGL) are the largest natural gas distribution utilities in Ontario. They are investigating technical and economic challenges of establishing a Renewable Natural Gas (RNG) program that would allow both utilities to provide their customers renewable natural gas. Electrigaz Technologies Inc. (Electrigaz) was hired by EGD and UGL to provide biogas engineering expertise to perform financial modeling and price evaluation for this RNG program.

Capital and operational costs were estimated for each scenario using the best available Ontario biogas market information. These can be found in the Electrigaz *Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Distribution Grid in Ontario—Biogas plant costing report*. These were used as a basis to evaluate and develop an appropriate pricing mechanism in this report.

A standardized financial model was developed to evaluate the Return on Equity (ROE) for each scenario under various RNG price points. EGD and UGL recommended an RNG price ceiling to balance the need to minimize the impacts on their customer's bills with the need of RNG producers to earn a reasonable return on the incremental capital and operating costs required to enable the market. Simulations were performed to establish the optimal RNG price points and energy volume thresholds to yield a target 11% ROE.

Based on the analysis performed, two distinct RNG price schedules, one for AD and one for landfills, are recommended. Within each schedule, two RNG prices are proposed around a specified energy volume threshold. This means that energy delivered below a set energy threshold will be paid at a higher price per gigajoule than the energy delivered above that energy threshold. This two-tiered approach was chosen to address the distinct characteristics of the anaerobic digestion (AD) and landfill gas (LFG) segments while facilitating the overarching objectives of simplicity and broad adoptability.

The following table presents recommended energy volume threshold and RNG price points.

RNG pricing			
AD Energy Volume Threshold		50 000	GJ/yr
AD RNG price below threshold	$	17.00	$/GJ
AD RNG price above threshold	$	11.00	$/GJ
LFG Energy Volume Threshold		150 000	GJ/yr
LFG RNG price below threshold	$	13.00	$/GJ
LFG RNG price above threshold	$	6.00	$/GJ

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The following table presents expected ROE value for each scenario.

Results	Project Cost	ROE
AD scenarios		
Baseline Farm	$ 4,448,919	-
Large Farm	$ 5,751,962	10.0%
Coop Farm	$ 8,200,289	11.1%
SSO (Municipal)	$ 31,524,253	1.3%
Industrial	$ 29,282,343	-
WWTP	$ 2,492,935	-
Landfill scenarios		
Small landfill	$ 5,077,647	10.5%
Medium landfill	$ 9,107,041	13.4%
Large landfill	$ 17,482,106	13.6%

The summary results above represent returns for each segment under the developed scenarios. In certain cases, the application of the model to a production scenario resulted in a negative ROE, indicating that production would not be viable at that price level. Where ROEs are negative, no figure is included in the table. Individual biogas projects returns will vary depending on prevailing market conditions and proponents' specific operational characteristics.

Glossary

Biogas	Gas produced from anaerobic digestion, mostly composed of CH_4 and CO_2
Biomethane	Methane extracted from a biogas upgrading system, also called Renewable Natural Gas (RNG)
Digestate	Nutrient rich material left following AD consisting of indigestible material and dead micro-organisms
Renewable Natural Gas	Biomethane interchangeable with natural gas
Substrate	Material uploaded into digesters

Abbreviations and units

AD	Anaerobic digestion
CGA	Canadian Gas Association
CH_4	Methane
CO_2	Carbon dioxide
C:N	Carbon/Nitrogen ratio
CSTR	Complete stirred tank reactor
d	Day
EPC	Engineering, Procurement and Construction
FIT	Feed in tariff
GHG	Greenhouse gases
GJ	Energy unit (Gigajoule)
H_2O	Water
HP injection pressure	High pressure (200 psig)
hr	Time unit (Hour)
H_2S	Hydrogen sulphide
IDC	Interest during construction
IP injection pressure	Intermediate pressure (60 psig)
kg	Mass unit (Kilogram)
kWe	Power unit (Kilowatt electrical)

kWh	Energy unit (Kilowatt-hour)
l	Volume unit (Litre)
LFG	Landfill gas
m^3	Volume unit (Cubic meter)
mg	Mass unit (Milligram)
MJ	Energy unit (MegaJoule)
MSW	Municipal solid waste
%mol	Concentration unit (molar percentage)
N_2	Nitrogen
N/D	Not defined
Nm^3	Volume unit (Normal cubic meter)
O_2	Oxygen
OPA	Ontario Power Authority
OPA FIT	Ontario Power Authority feed in tariff program
ppm	Concentration unit (part per million)
PSA	Pressure swing adsorption
psig	Pressure unit (pound square inch gauge)
RNG	Renewable natural gas
ROE	Return on equity
S	Sulphur
SSO	Source separated organics
t	Mass unit (Tonne)
TS	Total solids
VS	Volatile solids
WWTP	Wastewater treatment plant
XHP injection pressure	Extra high pressure (500 psig)
Yr	Year
°C	Temperature unit (Celsius degree)

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Drew Everett, Ed Seaward	Union Gas
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1 Introduction

Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (UGL) are the largest natural gas distribution utilities in Ontario. They are investigating technical and economic challenges of establishing a Renewable Natural Gas (RNG) program that would allow both utilities to provide their customers renewable natural gas. Electrigaz Technologies Inc. (Electrigaz) was hired by EGD and UGL to work with the utilities to perform financial modeling and price evaluation for this RNG program.

In the first phase of this study named: *Biogas plant costing report,* nine (9) scenarios were developed and capital and operational costs were obtained for each scenario using the best available Ontario biogas market information.

These costs are now used in this study to model an optimal RNG program.

1.1 Study objectives

The main objective of the study is to establish an appropriate RNG pricing model that would enable a viable RNG market in Ontario. The pricing model should balance the need for RNG producer requirements of a reasonable return on the incremental capital and operating costs to develop the supply stream and the utilities' customer need for minimal bill impact.

1.2 Methodology

Electrigaz developed capital and operational costs for each scenario (found in Electrigaz's report titled *Biogas Plant Costing Report*) and developed a preliminary financial model. The financial model was reviewed, expanded and validated by the Utilities and input was provided on pricing constraints. This updated financial model was then used by Electrigaz, working together with the Utilities, to evaluate projects Return on Equity (ROE). An ROE of 11% was chosen as an appropriate target informed by the OPA FIT program.

Various RNG price points were applied to landfill and AD financial models to evaluate projects potential ROE. RNG pricing simulations were used to determine the optimal pricing model.

For the purpose of financial modeling, a 20 years project life has been assumed.

2 Financial model

A financial model was developed to evaluate project return on equity (ROE) given a set of economic assumptions and RNG pricing model.

The return is calculated using a standard discounted cash flow model. The model takes into consideration multiple revenues, operating expenses, depreciation, and tax modeling such a Capital Cost Allowance (CCA). The Ontario tax information was provided by EGD and UGL. The model calculations were reviewed and approved by EGD and UGL. See Appendix 1: pro-formas for calculation details.

2.1 Economic assumptions

The following economic assumptions were taken into consideration for the financial modeling of all scenarios:

Macro-economic references

- Global inflation: 2.25%. [1] [2]
- Capital Cost Allowance (CCA) Class 1 rate: 6%. [3]
- Capital Cost Allowance (CCA) Class 8 rate: 20%. [3]
- Capital Cost Allowance (CCA) Class 43.2 rate: 50%. [4]
- RNG price escalation factor: 30% of inflation. [2]
- Equity cash flow payable as dividends: 100%.
- Straight-line depreciation on 20 years. [5] [6]

Agricultural and Industrial scenarios assumptions

- A 25% annual gate fee deflation is considered.
- Interest on loan: 7%. [7] [8]
- Equity: 40%. [10]
- Debt: 60%. [10]

SSO and WWTP scenarios assumptions

- No gate fee deflation is considered.
- Interest on loan: 4.5% [9]
- Equity: 20%.
- Debt: 80%.

All landfill scenarios assumptions

- Interest on loan: 7% [7] [8]
- Equity: 40%. [10]
- Debt: 60%. [10]

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2.2 Revenues

Two potential revenues were considered:

1. Gate fees: Revenue collected by the project to treat other people's organic waste. Gate fees are proportional to amount of substrates processed. Moreover, gate fees are prone to waste disposal market fluctuations. In some scenarios gate fee deflation was considered. See each scenario economic assumptions.
2. RNG: Revenue collected for the selling of RNG. Note that there is an above set energy threshold revenue and a below energy threshold revenue

2.3 Depreciation

Linear twenty (20) years depreciation was assumed for the entire project capital cost.

2.4 Tax modeling

Capital cost allowance for Class 1, Class 8 and Class 43.2 were taken into consideration for the accelerated depreciation of assets. Moreover, tax modeling was performed to accurately represent benefits of CCA, tax loss carry forward, future tax expenses, etc.

Note that land purchase and site work are not included in CCA calculations.

2.5 Return on equity

ROE was calculated using dividends to equity and tax modeling benefits.

3 RNG Program and Findings

In the first phase of this study, *Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Distribution Grid in Ontario—Biogas plant costing report*, capital and operational costs were estimated for each scenario using the best available Ontario biogas market information. Working together with the Utilities, ROE for each scenario under various RNG price points was evaluated with the financial model. EGD and UGL recommended an RNG price ceiling to minimize the impact on their respective customers.

Simulations were performed to establish optimal and acceptable RNG price points and energy volume thresholds to yield a target 11% ROE. Various RNG price points were applied to landfill and AD financial models to evaluate projects potential ROE.

Based on the analysis performed, two distinct RNG price schedules, one for anaerobic digestion and one for landfills, are recommended. Within each schedule, two RNG prices are proposed around a specified energy volume threshold. This means that, on an annual basis, energy delivered on below a set energy threshold will be paid at a higher price per gigajoule than the energy delivered above that energy threshold. This two tiered approach was chosen to address the distinct characteristics of the AD and LFG segments while facilitating the overarching objectives of simplicity and broad adoptability.

The following table presents recommended energy volume threshold and RNG price points.

Table 1: Recommended energy volume threshold and RNG prices

RNG pricing			
AD Energy Volume Threshold		50 000	GJ/yr
AD RNG price below threshold	$	17.00	$/GJ
AD RNG price above threshold	$	11.00	$/GJ
LFG Energy Volume Threshold		150 000	GJ/yr
LFG RNG price below threshold	$	13.00	$/GJ
LFG RNG price above threshold	$	6.00	$/GJ

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The following table presents expected ROE value for each scenario.

Table 2: ROE for each scenario[1]

Results	Project Cost	ROE
AD scenarios		
Baseline Farm	$ 4,448,919	-
Large Farm	$ 5,751,962	10.0%
Coop Farm	$ 8,200,289	11.1%
SSO (Municipal)	$ 31,524,253	1.3%
Industrial	$ 29,282,343	-
WWTP	$ 2,492,935	-
Landfill scenarios		
Small landfill	$ 5,077,647	10.5%
Medium landfill	$ 9,107,041	13.4%
Large landfill	$ 17,482,106	13.6%

It is important to note that the blended price for larger scenarios is significantly lower than the set above threshold RNG price. For example, in the large landfill scenario the blended price is approximately $7.5/GJ because the first 150,000 GJ (paid at $13) represent a small fraction of the energy delivered throughout the year.

The ROE summary results above represent returns for each scenario. Individual biogas project returns will vary depending on prevailing market conditions and proponents' specific operational characteristics.

[1] Large landfill capital cost consolidates first year capital cost and inflated year-12 re-investment.

References

1. Ontario Power Authority, (2009). *Proposed Feed-in Tariff Price Schedule. Stakeholder Engagement –Session 4.* http://fit.powerauthority.on.ca/Storage/10147_FIT_Stakeholder_Engagement_-_Session_4_FIT_Price_Schedule_FINAL_(HP).pdf
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Appendix 1: Pro-formas

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Baseline agricultural scenario			1	2	3	4	5	6	7	8	9	10
Revenu			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Biomethane price sub treshold			17.00	17.11	17.23	17.35	17.46	17.58	17.70	17.82	17.94	18.06
Biomethane price above treshold			11.00	11.07	11.15	11.22	11.30	11.38	11.45	11.53	11.61	11.69
Biomethane	$/GJ		$ 450,686	$ 453,728	$ 456,791	$ 459,874	$ 462,978	$ 466,103	$ 469,250	$ 472,417	$ 475,606	$ 478,816
Gate fees			$ 280,000	$ 210,000	$ 157,500	$ 118,125	$ 88,594	$ 66,445	$ 49,834	$ 37,375	$ 28,032	$ 21,024
Total revenues			$ 730,686	$ 663,728	$ 614,291	$ 577,999	$ 551,572	$ 532,549	$ 519,084	$ 509,793	$ 503,638	$ 499,840
Production costs												
Production costs			$ 363,368	$ 371,544	$ 379,903	$ 388,451	$ 397,191	$ 406,128	$ 415,266	$ 424,610	$ 434,163	$ 443,932
EBITDA			$ 367,318	$ 292,185	$ 234,387	$ 189,548	$ 154,381	$ 126,421	$ 103,818	$ 85,183	$ 69,474	$ 55,908
Depreciation			$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146
EBIT			$ 150,172	$ 75,039	$ 17,242	-$ 27,598	-$ 62,765	-$ 90,725	-$ 113,328	-$ 131,963	-$ 147,672	-$ 161,238
Total Annual Payment			$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968
Principle payment			$ 65,113	$ 69,671	$ 74,548	$ 79,767	$ 85,350	$ 91,325	$ 97,717	$ 104,558	$ 111,877	$ 119,708
Interest payment			$ 186,855	$ 182,297	$ 177,420	$ 172,201	$ 166,618	$ 160,643	$ 154,250	$ 147,410	$ 140,091	$ 132,260
Principle Balance		$ 2,669,351	$ 2,604,238	$ 2,534,567	$ 2,460,018	$ 2,380,252	$ 2,294,902	$ 2,203,577	$ 2,105,859	$ 2,001,302	$ 1,889,425	$ 1,769,717
Net Income (before tax)			-$ 36,682	-$ 107,258	-$ 160,178	-$ 199,799	-$ 229,383	-$ 251,368	-$ 267,579	-$ 279,373	-$ 287,763	-$ 293,498
CCA Class 43.2 Factor		*100.0%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*	*0.2930%*	*0.1465%*
CCA Class 43.2 Eligible			$ 861,000	$ 1,291,500	$ 645,750	$ 322,875	$ 161,438	$ 80,719	$ 40,359	$ 20,180	$ 10,090	$ 5,045
CCA Class 8 Factor		*100.0%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*	*3.7749%*	*3.0199%*
CCA Class 8 Eligible			$ 22,700	$ 40,860	$ 32,688	$ 26,150	$ 20,920	$ 16,736	$ 13,389	$ 10,711	$ 8,569	$ 6,855
CCA Class 1 Factor		*100.0%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*	*3.7741%*	*3.5477%*
CCA Class 1 Eligible			$ 16,978	$ 32,937	$ 30,961	$ 29,103	$ 27,357	$ 25,716	$ 24,173	$ 22,722	$ 21,359	$ 20,077
Total Eligible CCA			$ 900,678	$ 1,365,297	$ 709,399	$ 378,129	$ 209,715	$ 123,171	$ 77,921	$ 53,613	$ 40,018	$ 31,978
Taxable Income			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			26.25%	25.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax			-$ 9,354	-$ 26,631	-$ 40,045	-$ 49,950	-$ 57,346	-$ 62,842	-$ 66,895	-$ 69,843	-$ 71,941	-$ 73,374
Net Income (after tax)			-$ 27,328	-$ 80,627	-$ 120,134	-$ 149,849	-$ 172,037	-$ 188,526	-$ 200,684	-$ 209,530	-$ 215,822	-$ 220,123
Cash Distributions												
Equity Dividend	at	100%	-$ 27,328	-$ 80,627	-$ 120,134	-$ 149,849	-$ 172,037	-$ 188,526	-$ 200,684	-$ 209,530	-$ 215,822	-$ 220,123
Depreciation			$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146
Future Income Tax Expense			-$ 9,354	-$ 26,631	-$ 40,045	-$ 49,950	-$ 57,346	-$ 62,842	-$ 66,895	-$ 69,843	-$ 71,941	-$ 73,374
Debt Repayment			-$ 65,113	-$ 69,671	-$ 74,548	-$ 79,767	-$ 85,350	-$ 91,325	-$ 97,717	-$ 104,558	-$ 111,877	-$ 119,708
Equity dividend		-$ 1,779,567	**$ 115,350**	**$ 40,217**	**-$ 17,580**	**-$ 62,420**	**-$ 97,587**	**-$ 125,547**	**-$ 148,150**	**-$ 166,785**	**-$ 182,494**	**-$ 196,060**
		31-Dec-11	31-Dec-12	31-Dec-13	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21
Equity ROE		#DIV/0!										

Baseline agricultural scenario	11	12	13	14	15	16	17	18	19	20
Revenu	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Biomethane price sub treshold	18.18	18.31	18.43	18.55	18.68	18.81	18.93	19.06	19.19	19.32
Biomethane price above treshold	11.77	11.84	11.92	12.01	12.09	12.17	12.25	12.33	12.42	12.50
Biomethane	$ 482,048	$ 485,302	$ 488,578	$ 491,876	$ 495,196	$ 498,539	$ 501,904	$ 505,292	$ 508,702	$ 512,136
Gate fees	$ 15,768	$ 11,826	$ 8,869	$ 6,652	$ 4,989	$ 3,742	$ 2,806	$ 2,105	$ 1,579	$ 1,184
Total revenues	$ 497,816	$ 497,128	$ 497,447	$ 498,528	$ 500,185	$ 502,280	$ 504,710	$ 507,396	$ 510,281	$ 513,320
Production costs										
Production costs	$ 453,920	$ 464,134	$ 474,577	$ 485,255	$ 496,173	$ 507,337	$ 518,752	$ 530,424	$ 542,358	$ 554,561
EBITDA	$ 43,896	$ 32,994	$ 22,871	$ 13,273	$ 4,012	-$ 5,056	-$ 14,042	-$ 23,028	-$ 32,078	-$ 41,241
Depreciation	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146
EBIT	-$ 173,250	-$ 184,152	-$ 194,275	-$ 203,873	-$ 213,134	-$ 222,202	-$ 231,188	-$ 240,173	-$ 249,223	-$ 258,387
Total Annual Payment	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968	$ 251,968
Principle payment	$ 128,088	$ 137,054	$ 146,648	$ 156,913	$ 167,897	$ 179,650	$ 192,225	$ 205,681	$ 220,078	$ 235,484
Interest payment	$ 123,880	$ 114,914	$ 105,320	$ 95,055	$ 84,071	$ 72,318	$ 59,743	$ 46,287	$ 31,889	$ 16,484
Principle Balance	$ 1,641,629	$ 1,504,575	$ 1,357,928	$ 1,201,015	$ 1,033,118	$ 853,468	$ 661,243	$ 455,562	$ 235,484	$ 0
Net Income (before tax)	-$ 297,131	-$ 299,066	-$ 299,596	-$ 298,928	-$ 297,205	-$ 294,521	-$ 290,931	-$ 286,460	-$ 281,113	-$ 274,871
CCA Class 43.2 Factor	*0.0732%*	*0.0366%*	*0.0183%*	*0.0092%*	*0.0046%*	*0.0023%*	*0.0011%*	*0.0006%*	*0.0003%*	*0.0001%*
CCA Class 43.2 Eligible	$ 2,522	$ 1,261	$ 631	$ 315	$ 158	$ 79	$ 39	$ 20	$ 10	$ 5
CCA Class 8 Factor	*2.4159%*	*1.9327%*	*1.5462%*	*1.2370%*	*0.9896%*	*0.7916%*	*0.6333%*	*0.5067%*	*0.4053%*	*0.3243%*
CCA Class 8 Eligible	$ 5,484	$ 4,387	$ 3,510	$ 2,808	$ 2,246	$ 1,797	$ 1,438	$ 1,150	$ 920	$ 736
CCA Class 1 Factor	*3.3348%*	*3.1347%*	*2.9467%*	*2.7699%*	*2.6037%*	*2.4474%*	*2.3006%*	*2.1626%*	*2.0328%*	*1.9108%*
CCA Class 1 Eligible	$ 18,873	$ 17,740	$ 16,676	$ 15,675	$ 14,735	$ 13,851	$ 13,020	$ 12,239	$ 11,504	$ 10,814
Total Eligible CCA	$ 26,879	$ 23,389	$ 20,816	$ 18,799	$ 17,139	$ 15,727	$ 14,497	$ 13,408	$ 12,434	$ 11,555
Taxable Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax	-$ 74,283	-$ 74,766	-$ 74,899	-$ 74,732	-$ 74,301	-$ 73,630	-$ 72,733	-$ 71,615	-$ 70,278	-$ 68,718
Net Income (after tax)	-$ 222,848	-$ 224,299	-$ 224,697	-$ 224,196	-$ 222,904	-$ 220,890	-$ 218,198	-$ 214,845	-$ 210,835	-$ 206,153
Cash Distributions										
Equity Dividend	-$ 222,848	-$ 224,299	-$ 224,697	-$ 224,196	-$ 222,904	-$ 220,890	-$ 218,198	-$ 214,845	-$ 210,835	-$ 206,153
Depreciation	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146	$ 217,146
Future Income Tax Expense	-$ 74,283	-$ 74,766	-$ 74,899	-$ 74,732	-$ 74,301	-$ 73,630	-$ 72,733	-$ 71,615	-$ 70,278	-$ 68,718
Debt Repayment	-$ 128,088	-$ 137,054	-$ 146,648	-$ 156,913	-$ 167,897	-$ 179,650	-$ 192,225	-$ 205,681	-$ 220,078	-$ 235,484
Equity dividend	**-$ 208,072**	**-$ 218,974**	**-$ 229,097**	**-$ 238,695**	**-$ 247,956**	**-$ 257,024**	**-$ 266,010**	**-$ 274,995**	**-$ 284,045**	**-$ 293,209**
	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31
Equity ROE										

Large agricultural scenario		1	2	3	4	5	6	7	8	9	10
RNG price sub treshold		17.00	17.11	17.23	17.35	17.46	17.58	17.70	17.82	17.94	18.06
RNG price above treshold		11.00	11.07	11.15	11.22	11.30	11.38	11.45	11.53	11.61	11.69
RNG		$ 896,459	$ 902,510	$ 908,602	$ 914,735	$ 920,910	$ 927,126	$ 933,384	$ 939,684	$ 946,027	$ 952,413
Gate fees		$ 581,000	$ 435,750	$ 326,813	$ 245,109	$ 183,832	$ 137,874	$ 103,406	$ 77,554	$ 58,166	$ 43,624
Total revenues		$ 1,477,459	$ 1,338,260	$ 1,235,415	$ 1,159,845	$ 1,104,742	$ 1,065,000	$ 1,036,790	$ 1,017,239	$ 1,004,193	$ 996,037
Operational costs											
Operational costs		$ 451,743	$ 461,907	$ 472,300	$ 482,927	$ 493,792	$ 504,903	$ 516,263	$ 527,879	$ 539,756	$ 551,901
EBITDA		$ 1,025,716	$ 876,353	$ 763,115	$ 676,918	$ 610,949	$ 560,097	$ 520,526	$ 489,360	$ 464,437	$ 444,136
Depreciation		$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648
EBIT		$ 745,068	$ 595,705	$ 482,467	$ 396,270	$ 330,301	$ 279,449	$ 239,878	$ 208,711	$ 183,788	$ 163,488
Debt service total annual payment		$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767
Principle payment		$ 84,184	$ 90,077	$ 96,383	$ 103,129	$ 110,348	$ 118,073	$ 126,338	$ 135,182	$ 144,644	$ 154,769
Interest payment		$ 241,582	$ 235,689	$ 229,384	$ 222,637	$ 215,418	$ 207,694	$ 199,429	$ 190,585	$ 181,122	$ 170,997
Principle Balance	$ 3,451,177	$ 3,366,993	$ 3,276,915	$ 3,180,533	$ 3,077,403	$ 2,967,055	$ 2,848,982	$ 2,722,644	$ 2,587,463	$ 2,442,818	$ 2,288,049
Net Income (before tax)		$ 503,486	$ 360,016	$ 253,083	$ 173,633	$ 114,883	$ 71,755	$ 40,450	$ 18,126	$ 2,666	-$ 7,509
CCA Class 43.2 Factor	*100.0%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*	*0.2930%*	*0.1465%*
CCA Class 43.2 Eligible		$ 1,148,250	$ 1,722,375	$ 861,188	$ 430,594	$ 215,297	$ 107,648	$ 53,824	$ 26,912	$ 13,456	$ 6,728
CCA Class 8 Factor	*100.0%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*	*3.7749%*	*3.0199%*
CCA Class 8 Eligible		$ 30,400	$ 54,720	$ 43,776	$ 35,021	$ 28,017	$ 22,413	$ 17,931	$ 14,345	$ 11,476	$ 9,180
CCA Class 1 Factor	*100.0%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*	*3.7741%*	*3.5477%*
CCA Class 1 Eligible		$ 17,368	$ 33,694	$ 31,672	$ 29,772	$ 27,985	$ 26,306	$ 24,728	$ 23,244	$ 21,850	$ 20,539
Total Eligible CCA		$ 1,196,018	$ 1,810,789	$ 936,636	$ 495,386	$ 271,299	$ 156,368	$ 96,483	$ 64,501	$ 46,781	$ 36,447
Taxable Income		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		26.25%	25.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax		$ 128,389	$ 87,487	$ 63,271	$ 43,408	$ 28,721	$ 17,939	$ 10,112	$ 4,532	$ 667	-$ 1,877
Net Income (after tax)		$ 375,097	$ 272,529	$ 189,812	$ 130,225	$ 86,162	$ 53,816	$ 30,337	$ 13,595	$ 2,000	-$ 5,632
Cash Distributions											
Equity Dividend	at 100%	$ 375,097	$ 272,529	$ 189,812	$ 130,225	$ 86,162	$ 53,816	$ 30,337	$ 13,595	$ 2,000	-$ 5,632
Depreciation		$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648
Future Income Tax Expense		$ 128,389	$ 87,487	$ 63,271	$ 43,408	$ 28,721	$ 17,939	$ 10,112	$ 4,532	$ 667	-$ 1,877
Debt Repayment		-$ 84,184	-$ 90,077	-$ 96,383	-$ 103,129	-$ 110,348	-$ 118,073	-$ 126,338	-$ 135,182	-$ 144,644	-$ 154,769
Equity dividend	-$ 2,300,785	**$ 699,950**	**$ 550,587**	**$ 437,348**	**$ 351,151**	**$ 285,183**	**$ 234,331**	**$ 194,760**	**$ 163,593**	**$ 138,670**	**$ 118,370**
	31-Dec-11	31-Dec-12	31-Dec-13	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21
Equity ROE	9.96%										

Large agricultural scenario	11	12	13	14	15	16	17	18	19	20
RNG price sub treshold	18.18	18.31	18.43	18.55	18.68	18.81	18.93	19.06	19.19	19.32
RNG price above treshold	11.77	11.84	11.92	12.01	12.09	12.17	12.25	12.33	12.42	12.50
RNG	$ 958,842	$ 965,314	$ 971,830	$ 978,390	$ 984,994	$ 991,642	$ 998,336	$ 1,005,075	$ 1,011,859	$ 1,018,689
Gate fees	$ 32,718	$ 24,539	$ 18,404	$ 13,803	$ 10,352	$ 7,764	$ 5,823	$ 4,367	$ 3,276	$ 2,457
Total revenues	$ 991,560	$ 989,853	$ 990,234	$ 992,193	$ 995,346	$ 999,407	$ 1,004,159	$ 1,009,442	$ 1,015,135	$ 1,021,146
Operational costs										
Operational costs	$ 564,319	$ 577,016	$ 589,999	$ 603,274	$ 616,847	$ 630,726	$ 644,918	$ 659,428	$ 674,265	$ 689,436
EBITDA	$ 427,241	$ 412,837	$ 400,235	$ 388,919	$ 378,499	$ 368,680	$ 359,242	$ 350,014	$ 340,869	$ 331,709
Depreciation	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648
EBIT	$ 146,593	$ 132,189	$ 119,587	$ 108,271	$ 97,851	$ 88,032	$ 78,593	$ 69,366	$ 60,221	$ 51,061
Debt service total annual payment	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767	$ 325,767
Principle payment	$ 165,603	$ 177,195	$ 189,599	$ 202,871	$ 217,072	$ 232,267	$ 248,526	$ 265,923	$ 284,537	$ 304,455
Interest payment	$ 160,163	$ 148,571	$ 136,168	$ 122,896	$ 108,695	$ 93,500	$ 77,241	$ 59,844	$ 41,229	$ 21,312
Principle Balance	$ 2,122,446	$ 1,945,250	$ 1,755,651	$ 1,552,780	$ 1,335,708	$ 1,103,441	$ 854,915	$ 588,992	$ 304,455	$ 0
Net Income (before tax)	-$ 13,570	-$ 16,382	-$ 16,580	-$ 14,625	-$ 10,844	-$ 5,467	$ 1,353	$ 9,522	$ 18,992	$ 29,749
CCA Class 43.2 Factor	*0.0732%*	*0.0366%*	*0.0183%*	*0.0092%*	*0.0046%*	*0.0023%*	*0.0011%*	*0.0006%*	*0.0003%*	*0.0001%*
CCA Class 43.2 Eligible	$ 3,364	$ 1,682	$ 841	$ 421	$ 210	$ 105	$ 53	$ 26	$ 13	$ 7
CCA Class 8 Factor	*2.4159%*	*1.9327%*	*1.5462%*	*1.2370%*	*0.9896%*	*0.7916%*	*0.6333%*	*0.5067%*	*0.4053%*	*0.3243%*
CCA Class 8 Eligible	$ 7,344	$ 5,876	$ 4,700	$ 3,760	$ 3,008	$ 2,407	$ 1,925	$ 1,540	$ 1,232	$ 986
CCA Class 1 Factor	*3.3348%*	*3.1347%*	*2.9467%*	*2.7699%*	*2.6037%*	*2.4474%*	*2.3006%*	*2.1626%*	*2.0328%*	*1.9108%*
CCA Class 1 Eligible	$ 19,306	$ 18,148	$ 17,059	$ 16,036	$ 15,073	$ 14,169	$ 13,319	$ 12,520	$ 11,769	$ 11,062
Total Eligible CCA	$ 30,015	$ 25,705	$ 22,600	$ 20,216	$ 18,292	$ 16,681	$ 15,297	$ 14,086	$ 13,014	$ 12,055
Taxable Income	$ -	$ -	$ -	$ 189,259	$ 251,512	$ 258,500	$ 266,704	$ 276,084	$ 286,626	$ 298,343
	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax	-$ 3,393	-$ 4,096	-$ 4,145	-$ 3,656	-$ 2,711	-$ 1,367	$ 338	$ 2,380	$ 4,748	$ 7,437
Net Income (after tax)	-$ 10,178	-$ 12,287	-$ 12,435	-$ 10,968	-$ 8,133	-$ 4,100	$ 1,014	$ 7,141	$ 14,244	$ 22,312
Cash Distributions										
Equity Dividend	-$ 10,178	-$ 12,287	-$ 12,435	-$ 10,968	-$ 8,133	-$ 4,100	$ 1,014	$ 7,141	$ 14,244	$ 22,312
Depreciation	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648	$ 280,648
Future Income Tax Expense	-$ 3,393	-$ 4,096	-$ 4,145	-$ 50,971	-$ 65,589	-$ 65,992	-$ 66,338	-$ 66,640	-$ 66,909	-$ 67,148
Debt Repayment	-$ 165,603	-$ 177,195	-$ 189,599	-$ 202,871	-$ 217,072	-$ 232,267	-$ 248,526	-$ 265,923	-$ 284,537	-$ 304,455
Equity dividend	**$ 101,475**	**$ 87,070**	**$ 74,468**	**$ 15,838**	**-$ 10,146**	**-$ 21,711**	**-$ 33,201**	**-$ 44,774**	**-$ 56,554**	**-$ 68,643**
	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31

Coop agricultural scenario			1	2	3	4	5	6	7	8	9	10
Revenu			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Biomethane price sub treshold			17.00	17.11	17.23	17.35	17.46	17.58	17.70	17.82	17.94	18.06
Biomethane price above treshold			11.00	11.07	11.15	11.22	11.30	11.38	11.45	11.53	11.61	11.69
Biomethane	0.00 $/GJ		$ 1,198,881	$ 1,206,974	$ 1,215,121	$ 1,223,323	$ 1,231,580	$ 1,239,893	$ 1,248,263	$ 1,256,688	$ 1,265,171	$ 1,273,711
Gate fees			$ 875,000	$ 656,250	$ 492,188	$ 369,141	$ 276,855	$ 207,642	$ 155,731	$ 116,798	$ 87,599	$ 65,699
Total revenues			$ 2,073,881	$ 1,863,224	$ 1,707,308	$ 1,592,463	$ 1,508,436	$ 1,447,535	$ 1,403,994	$ 1,373,487	$ 1,352,770	$ 1,339,410
Production costs												
Production costs			$ 573,583	$ 586,488	$ 599,684	$ 613,177	$ 626,974	$ 641,080	$ 655,505	$ 670,254	$ 685,334	$ 700,754
EBITDA			$ 1,500,299	$ 1,276,735	$ 1,107,624	$ 979,286	$ 881,462	$ 806,454	$ 748,489	$ 703,233	$ 667,435	$ 638,656
Depreciation			$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364
EBIT			$ 1,098,934	$ 875,371	$ 706,259	$ 577,922	$ 480,098	$ 405,090	$ 347,125	$ 301,869	$ 266,071	$ 237,291
Total Annual Payment			$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430
Principle payment			$ 120,017	$ 128,419	$ 137,408	$ 147,027	$ 157,318	$ 168,331	$ 180,114	$ 192,722	$ 206,212	$ 220,647
Interest payment			$ 344,412	$ 336,011	$ 327,022	$ 317,403	$ 307,111	$ 296,099	$ 284,316	$ 271,708	$ 258,217	$ 243,782
Principle Balance		$ 4,920,173	$ 4,800,156	$ 4,671,737	$ 4,534,329	$ 4,387,303	$ 4,229,985	$ 4,061,654	$ 3,881,540	$ 3,688,818	$ 3,482,606	$ 3,261,959
Net Income (before tax)			$ 754,522	$ 539,360	$ 379,238	$ 260,519	$ 172,986	$ 108,991	$ 62,809	$ 30,161	$ 7,854	-$ 6,491
CCA Class 43.2 Factor		*100.0%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*	*0.2930%*	*0.1465%*
CCA Class 43.2 Eligible			$ 1,716,250	$ 2,574,375	$ 1,287,188	$ 643,594	$ 321,797	$ 160,898	$ 80,449	$ 40,225	$ 20,112	$ 10,056
CCA Class 8 Factor		*100.0%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*	*3.7749%*	*3.0199%*
CCA Class 8 Eligible			$ 39,600	$ 71,280	$ 57,024	$ 45,619	$ 36,495	$ 29,196	$ 23,357	$ 18,686	$ 14,948	$ 11,959
CCA Class 1 Factor		*100.0%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*	*3.7741%*	*3.5477%*
CCA Class 1 Eligible			$ 17,128	$ 33,228	$ 31,234	$ 29,360	$ 27,599	$ 25,943	$ 24,386	$ 22,923	$ 21,548	$ 20,255
Total Eligible CCA			$ 1,772,978	$ 2,678,883	$ 1,375,446	$ 718,573	$ 385,891	$ 216,038	$ 128,193	$ 81,833	$ 56,608	$ 42,270
Taxable Income			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			26.25%	25.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax			$ 192,403	$ 131,067	$ 94,809	$ 65,130	$ 43,247	$ 27,248	$ 15,702	$ 7,540	$ 1,963	-$ 1,623
Net Income (after tax)			$ 562,119	$ 408,293	$ 284,428	$ 195,389	$ 129,740	$ 81,743	$ 47,107	$ 22,621	$ 5,890	-$ 4,868
Cash Distributions												
Equity Dividend	at	100%	$ 562,119	$ 408,293	$ 284,428	$ 195,389	$ 129,740	$ 81,743	$ 47,107	$ 22,621	$ 5,890	-$ 4,868
Depreciation			$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364
Future Income Tax Expense			$ 192,403	$ 131,067	$ 94,809	$ 65,130	$ 43,247	$ 27,248	$ 15,702	$ 7,540	$ 1,963	-$ 1,623
Debt Repayment			-$ 120,017	-$ 128,419	-$ 137,408	-$ 147,027	-$ 157,318	-$ 168,331	-$ 180,114	-$ 192,722	-$ 206,212	-$ 220,647
Equity dividend		-$ 3,280,116	**$ 1,035,869**	**$ 812,306**	**$ 643,194**	**$ 514,857**	**$ 417,032**	**$ 342,025**	**$ 284,059**	**$ 238,804**	**$ 203,006**	**$ 174,226**
		31-Dec-11	31-Dec-12	31-Dec-13	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21
Equity ROE		11.12%										

Coop agricultural scenario	11	12	13	14	15	16	17	18	19	20
Revenu	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Biomethane price sub treshold	18.18	18.31	18.43	18.55	18.68	18.81	18.93	19.06	19.19	19.32
Biomethane price above treshold	11.77	11.84	11.92	12.01	12.09	12.17	12.25	12.33	12.42	12.50
Biomethane	$ 1,282,308	$ 1,290,964	$ 1,299,678	$ 1,308,451	$ 1,317,283	$ 1,326,175	$ 1,335,126	$ 1,344,138	$ 1,353,211	$ 1,362,345
Gate fees	$ 49,274	$ 36,956	$ 27,717	$ 20,788	$ 15,591	$ 11,693	$ 8,770	$ 6,577	$ 4,933	$ 3,700
Total revenues	$ 1,331,583	$ 1,327,920	$ 1,327,395	$ 1,329,238	$ 1,332,874	$ 1,337,868	$ 1,343,896	$ 1,350,716	$ 1,358,144	$ 1,366,045
Production costs										
Production costs	$ 716,521	$ 732,643	$ 749,128	$ 765,983	$ 783,218	$ 800,840	$ 818,859	$ 837,283	$ 856,122	$ 875,385
EBITDA	$ 615,061	$ 595,277	$ 578,267	$ 563,256	$ 549,656	$ 537,028	$ 525,037	$ 513,432	$ 502,022	$ 490,660
Depreciation	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364
EBIT	$ 213,697	$ 193,912	$ 176,903	$ 161,891	$ 148,292	$ 135,663	$ 123,673	$ 112,068	$ 100,658	$ 89,296
Total Annual Payment	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430	$ 464,430
Principle payment	$ 236,092	$ 252,619	$ 270,302	$ 289,223	$ 309,469	$ 331,132	$ 354,311	$ 379,113	$ 405,651	$ 434,046
Interest payment	$ 228,337	$ 211,811	$ 194,127	$ 175,206	$ 154,961	$ 133,298	$ 110,118	$ 85,317	$ 58,779	$ 30,383
Principle Balance	$ 3,025,867	$ 2,773,248	$ 2,502,945	$ 2,213,722	$ 1,904,253	$ 1,573,121	$ 1,218,810	$ 839,697	$ 434,046	$ 0
Net Income (before tax)	-$ 14,640	-$ 17,898	-$ 17,225	-$ 13,315	-$ 6,669	$ 2,365	$ 13,554	$ 26,751	$ 41,879	$ 58,913
CCA Class 43.2 Factor	*0.0732%*	*0.0366%*	*0.0183%*	*0.0092%*	*0.0046%*	*0.0023%*	*0.0011%*	*0.0006%*	*0.0003%*	*0.0001%*
CCA Class 43.2 Eligible	$ 5,028	$ 2,514	$ 1,257	$ 629	$ 314	$ 157	$ 79	$ 39	$ 20	$ 10
CCA Class 8 Factor	*2.4159%*	*1.9327%*	*1.5462%*	*1.2370%*	*0.9896%*	*0.7916%*	*0.6333%*	*0.5067%*	*0.4053%*	*0.3243%*
CCA Class 8 Eligible	$ 9,567	$ 7,654	$ 6,123	$ 4,898	$ 3,919	$ 3,135	$ 2,508	$ 2,006	$ 1,605	$ 1,284
CCA Class 1 Factor	*3.3348%*	*3.1347%*	*2.9467%*	*2.7699%*	*2.6037%*	*2.4474%*	*2.3006%*	*2.1626%*	*2.0328%*	*1.9108%*
CCA Class 1 Eligible	$ 19,040	$ 17,897	$ 16,823	$ 15,814	$ 14,865	$ 13,973	$ 13,135	$ 12,347	$ 11,606	$ 10,910
Total Eligible CCA	$ 33,635	$ 28,065	$ 24,203	$ 21,341	$ 19,098	$ 17,265	$ 15,721	$ 14,392	$ 13,231	$ 12,203
Taxable Income	$ -	$ -	$ -	$ 302,015	$ 375,597	$ 386,465	$ 399,197	$ 413,723	$ 430,013	$ 448,074
	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax	-$ 3,660	-$ 4,475	-$ 4,306	-$ 3,329	-$ 1,667	$ 591	$ 3,389	$ 6,688	$ 10,470	$ 14,728
Net Income (after tax)	-$ 10,980	-$ 13,424	-$ 12,918	-$ 9,986	-$ 5,002	$ 1,774	$ 10,166	$ 20,064	$ 31,409	$ 44,185
Cash Distributions										
Equity Dividend	-$ 10,980	-$ 13,424	-$ 12,918	-$ 9,986	-$ 5,002	$ 1,774	$ 10,166	$ 20,064	$ 31,409	$ 44,185
Depreciation	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364	$ 401,364
Future Income Tax Expense	-$ 3,660	-$ 4,475	-$ 4,306	-$ 78,833	-$ 95,567	-$ 96,025	-$ 96,411	-$ 96,743	-$ 97,033	-$ 97,290
Debt Repayment	-$ 236,092	-$ 252,619	-$ 270,302	-$ 289,223	-$ 309,469	-$ 331,132	-$ 354,311	-$ 379,113	-$ 405,651	-$ 434,046
Equity dividend	**$ 150,632**	**$ 130,847**	**$ 113,838**	**$ 23,322**	**-$ 8,673**	**-$ 24,018**	**-$ 39,192**	**-$ 54,428**	**-$ 69,911**	**-$ 85,788**
	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31
Equity ROE										

SSO scenario			1	2	3	4	5	6	7	8	9	10
Revenu			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Biomethane price sub treshold			17.00	17.11	17.23	17.35	17.46	17.58	17.70	17.82	17.94	18.06
Biomethane price above treshold			11.00	11.07	11.15	11.22	11.30	11.38	11.45	11.53	11.61	11.69
Biomethane	$/GJ		$ 1,675,708	$ 1,687,019	$ 1,698,406	$ 1,709,870	$ 1,721,412	$ 1,733,031	$ 1,744,729	$ 1,756,506	$ 1,768,363	$ 1,780,299
Gate fees			$ 3,240,000	$ 3,312,900	$ 3,387,440	$ 3,463,658	$ 3,541,590	$ 3,621,276	$ 3,702,754	$ 3,786,066	$ 3,871,253	$ 3,958,356
Total revenues			$ 4,915,708	$ 4,999,919	$ 5,085,846	$ 5,173,528	$ 5,263,002	$ 5,354,307	$ 5,447,484	$ 5,542,573	$ 5,639,616	$ 5,738,655
Production costs												
Production costs			$ 2,763,609	$ 2,825,790	$ 2,889,370	$ 2,954,381	$ 3,020,854	$ 3,088,824	$ 3,158,322	$ 3,229,384	$ 3,302,046	$ 3,376,342
EBITDA			$ 2,152,099	$ 2,174,129	$ 2,196,476	$ 2,219,147	$ 2,242,147	$ 2,265,483	$ 2,289,162	$ 2,313,188	$ 2,337,570	$ 2,362,314
Depreciation			$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225
EBIT			$ 650,874	$ 672,904	$ 695,251	$ 717,922	$ 740,922	$ 764,258	$ 787,936	$ 811,963	$ 836,345	$ 861,088
Total Annual Payment			$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770
Principle payment			$ 803,897	$ 840,073	$ 877,876	$ 917,380	$ 958,662	$ 1,001,802	$ 1,046,883	$ 1,093,993	$ 1,143,223	$ 1,194,668
Interest payment			$ 1,134,873	$ 1,098,698	$ 1,060,894	$ 1,021,390	$ 980,108	$ 936,968	$ 891,887	$ 844,777	$ 795,548	$ 744,103
Principle Balance	$	25,219,402	$ 24,415,505	$ 23,575,432	$ 22,697,556	$ 21,780,176	$ 20,821,513	$ 19,819,711	$ 18,772,828	$ 17,678,834	$ 16,535,612	$ 15,340,944
Net Income (before tax)			-$ 483,999	-$ 425,794	-$ 365,643	-$ 303,468	-$ 239,186	-$ 172,710	-$ 103,951	-$ 32,814	$ 40,797	$ 116,986
CCA Class 43.2 Factor		*100.0%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*	*0.2930%*	*0.1465%*
CCA Class 43.2 Eligible			$ 6,066,563	$ 9,099,844	$ 4,549,922	$ 2,274,961	$ 1,137,480	$ 568,740	$ 284,370	$ 142,185	$ 71,093	$ 35,546
CCA Class 8 Factor		*100.0%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*	*3.7749%*	*3.0199%*
CCA Class 8 Eligible			$ 107,000	$ 192,600	$ 154,080	$ 123,264	$ 98,611	$ 78,889	$ 63,111	$ 50,489	$ 40,391	$ 32,313
CCA Class 1 Factor		*100.0%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*	*3.7741%*	*3.5477%*
CCA Class 1 Eligible			$ 103,048	$ 199,913	$ 187,918	$ 176,643	$ 166,044	$ 156,082	$ 146,717	$ 137,914	$ 129,639	$ 121,861
Total Eligible CCA			$ 6,276,610	$ 9,492,357	$ 4,891,920	$ 2,574,868	$ 1,402,136	$ 803,711	$ 494,198	$ 330,588	$ 241,123	$ 189,720
Taxable Income			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			26.25%	25.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax			-$ 123,420	-$ 104,029	-$ 91,411	-$ 75,867	-$ 59,796	-$ 43,177	-$ 25,988	-$ 8,204	$ 10,199	$ 29,246
Net Income (after tax)			-$ 360,579	-$ 321,766	-$ 274,233	-$ 227,601	-$ 179,389	-$ 129,532	-$ 77,963	-$ 24,611	$ 30,598	$ 87,739
Cash Distributions												
Equity Dividend	at	100%	-$ 360,579	-$ 321,766	-$ 274,233	-$ 227,601	-$ 179,389	-$ 129,532	-$ 77,963	-$ 24,611	$ 30,598	$ 87,739
Depreciation			$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225
Future Income Tax Expense			-$ 123,420	-$ 104,029	-$ 91,411	-$ 75,867	-$ 59,796	-$ 43,177	-$ 25,988	-$ 8,204	$ 10,199	$ 29,246
Debt Repayment			-$ 803,897	-$ 840,073	-$ 877,876	-$ 917,380	-$ 958,662	-$ 1,001,802	-$ 1,046,883	-$ 1,093,993	-$ 1,143,223	-$ 1,194,668
Equity dividend	-$	6,304,851	**$ 213,329**	**$ 235,358**	**$ 257,706**	**$ 280,377**	**$ 303,377**	**$ 326,713**	**$ 350,391**	**$ 374,418**	**$ 398,800**	**$ 423,543**
		31-Dec-11	31-Dec-12	31-Dec-13	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21
Equity ROE		1.32%										

SSO scenario	11	12	13	14	15	16	17	18	19	20
Revenu	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Biomethane price sub treshold	18.18	18.31	18.43	18.55	18.68	18.81	18.93	19.06	19.19	19.32
Biomethane price above treshold	11.77	11.84	11.92	12.01	12.09	12.17	12.25	12.33	12.42	12.50
Biomethane	$ 1,792,316	$ 1,804,414	$ 1,816,594	$ 1,828,856	$ 1,841,201	$ 1,853,629	$ 1,866,141	$ 1,878,737	$ 1,891,419	$ 1,904,186
Gate fees	$ 4,047,419	$ 4,138,486	$ 4,231,602	$ 4,326,813	$ 4,424,166	$ 4,523,710	$ 4,625,494	$ 4,729,567	$ 4,835,982	$ 4,944,792
Total revenues	$ 5,839,735	$ 5,942,900	$ 6,048,196	$ 6,155,669	$ 6,265,367	$ 6,377,339	$ 6,491,634	$ 6,608,305	$ 6,727,401	$ 6,848,978
Production costs										
Production costs	$ 3,452,309	$ 3,529,986	$ 3,609,411	$ 3,690,623	$ 3,773,662	$ 3,858,569	$ 3,945,387	$ 4,034,158	$ 4,124,927	$ 4,217,738
EBITDA	$ 2,387,426	$ 2,412,914	$ 2,438,785	$ 2,465,046	$ 2,491,705	$ 2,518,770	$ 2,546,248	$ 2,574,146	$ 2,602,475	$ 2,631,240
Depreciation	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225
EBIT	$ 886,201	$ 911,689	$ 937,560	$ 963,821	$ 990,480	$ 1,017,545	$ 1,045,022	$ 1,072,921	$ 1,101,249	$ 1,130,015
Total Annual Payment	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770	$ 1,938,770
Principle payment	$ 1,248,428	$ 1,304,607	$ 1,363,315	$ 1,424,664	$ 1,488,774	$ 1,555,768	$ 1,625,778	$ 1,698,938	$ 1,775,390	$ 1,855,283
Interest payment	$ 690,342	$ 634,163	$ 575,456	$ 514,107	$ 449,997	$ 383,002	$ 312,992	$ 239,832	$ 163,380	$ 83,488
Principle Balance	$ 14,092,516	$ 12,787,909	$ 11,424,594	$ 9,999,930	$ 8,511,157	$ 6,955,389	$ 5,329,611	$ 3,630,673	$ 1,855,283	-$ 0
Net Income (before tax)	$ 195,858	$ 277,526	$ 362,104	$ 449,714	$ 540,483	$ 634,543	$ 732,030	$ 833,089	$ 937,869	$ 1,046,528
CCA Class 43.2 Factor	*0.0732%*	*0.0366%*	*0.0183%*	*0.0092%*	*0.0046%*	*0.0023%*	*0.0011%*	*0.0006%*	*0.0003%*	*0.0001%*
CCA Class 43.2 Eligible	$ 17,773	$ 8,887	$ 4,443	$ 2,222	$ 1,111	$ 555	$ 278	$ 139	$ 69	$ 35
CCA Class 8 Factor	*2.4159%*	*1.9327%*	*1.5462%*	*1.2370%*	*0.9896%*	*0.7916%*	*0.6333%*	*0.5067%*	*0.4053%*	*0.3243%*
CCA Class 8 Eligible	$ 25,850	$ 20,680	$ 16,544	$ 13,235	$ 10,588	$ 8,471	$ 6,777	$ 5,421	$ 4,337	$ 3,470
CCA Class 1 Factor	*3.3348%*	*3.1347%*	*2.9467%*	*2.7699%*	*2.6037%*	*2.4474%*	*2.3006%*	*2.1626%*	*2.0328%*	*1.9108%*
CCA Class 1 Eligible	$ 114,549	$ 107,676	$ 101,216	$ 95,143	$ 89,434	$ 84,068	$ 79,024	$ 74,283	$ 69,826	$ 65,636
Total Eligible CCA	$ 158,173	$ 137,243	$ 122,203	$ 110,600	$ 101,133	$ 93,094	$ 86,078	$ 79,843	$ 74,232	$ 69,140
Taxable Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,492,021	$ 2,364,862	$ 2,478,612
	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax	$ 48,965	$ 69,381	$ 90,526	$ 112,429	$ 135,121	$ 158,636	$ 183,007	$ 208,272	$ 234,467	$ 261,632
Net Income (after tax)	$ 146,894	$ 208,144	$ 271,578	$ 337,286	$ 405,363	$ 475,907	$ 549,022	$ 624,817	$ 703,402	$ 784,896
Cash Distributions										
Equity Dividend	$ 146,894	$ 208,144	$ 271,578	$ 337,286	$ 405,363	$ 475,907	$ 549,022	$ 624,817	$ 703,402	$ 784,896
Depreciation	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225	$ 1,501,225
Future Income Tax Expense	$ 48,965	$ 69,381	$ 90,526	$ 112,429	$ 135,121	$ 158,636	$ 183,007	-$ 164,733	-$ 356,748	-$ 358,021
Debt Repayment	-$ 1,248,428	-$ 1,304,607	-$ 1,363,315	-$ 1,424,664	-$ 1,488,774	-$ 1,555,768	-$ 1,625,778	-$ 1,698,938	-$ 1,775,390	-$ 1,855,283
Equity dividend	**$ 448,656**	**$ 474,144**	**$ 500,015**	**$ 526,276**	**$ 552,935**	**$ 579,999**	**$ 607,477**	**$ 262,371**	**$ 72,489**	**$ 72,817**
	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31

Industrial scenario			1	2	3	4	5	6	7	8	9	10
Revenu			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Biomethane price sub treshold			17.00	17.11	17.23	17.35	17.46	17.58	17.70	17.82	17.94	18.06
Biomethane price above treshold			11.00	11.07	11.15	11.22	11.30	11.38	11.45	11.53	11.61	11.69
Biomethane	$/GJ		$ 2,070,667	$ 2,084,644	$ 2,098,715	$ 2,112,881	$ 2,127,143	$ 2,141,501	$ 2,155,957	$ 2,170,509	$ 2,185,160	$ 2,199,910
Gate fees			$ 4,585,000	$ 3,438,750	$ 2,579,063	$ 1,934,297	$ 1,450,723	$ 1,088,042	$ 816,031	$ 612,024	$ 459,018	$ 344,263
Total revenues			$ 6,655,667	$ 5,523,394	$ 4,677,777	$ 4,047,178	$ 3,577,866	$ 3,229,543	$ 2,971,988	$ 2,782,533	$ 2,644,178	$ 2,544,173
Production costs												
Production costs			$ 2,830,727	$ 2,894,418	$ 2,959,542	$ 3,026,132	$ 3,094,220	$ 3,163,840	$ 3,235,026	$ 3,307,815	$ 3,382,240	$ 3,458,341
EBITDA			$ 3,824,940	$ 2,628,976	$ 1,718,235	$ 1,021,046	$ 483,646	$ 65,703	-$ 263,038	-$ 525,282	-$ 738,062	-$ 914,167
Depreciation			$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191
EBIT			$ 2,470,749	$ 1,274,785	$ 364,044	-$ 333,145	-$ 870,545	-$ 1,288,487	-$ 1,617,229	-$ 1,879,472	-$ 2,092,253	-$ 2,268,358
Total Annual Payment			$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428
Principle payment			$ 428,569	$ 458,569	$ 490,669	$ 525,016	$ 561,767	$ 601,090	$ 643,167	$ 688,188	$ 736,362	$ 787,907
Interest payment			$ 1,229,858	$ 1,199,859	$ 1,167,759	$ 1,133,412	$ 1,096,661	$ 1,057,337	$ 1,015,261	$ 970,239	$ 922,066	$ 870,521
Principle Balance		$ 17,569,406	$ 17,140,837	$ 16,682,268	$ 16,191,599	$ 15,666,583	$ 15,104,816	$ 14,503,726	$ 13,860,559	$ 13,172,370	$ 12,436,009	$ 11,648,102
Net Income (before tax)			$ 1,240,891	$ 74,926	-$ 803,714	-$ 1,466,556	-$ 1,967,206	-$ 2,345,824	-$ 2,632,490	-$ 2,849,711	-$ 3,014,319	-$ 3,138,879
CCA Class 43.2 Factor		*100.0%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*	*0.2930%*	*0.1465%*
CCA Class 43.2 Eligible			$ 5,039,617	$ 7,559,425	$ 3,779,713	$ 1,889,856	$ 944,928	$ 472,464	$ 236,232	$ 118,116	$ 59,058	$ 29,529
CCA Class 8 Factor		*100.0%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*	*3.7749%*	*3.0199%*
CCA Class 8 Eligible			$ 91,400	$ 164,520	$ 131,616	$ 105,293	$ 84,234	$ 67,387	$ 53,910	$ 43,128	$ 34,502	$ 27,602
CCA Class 1 Factor		*100.0%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*	*3.7741%*	*3.5477%*
CCA Class 1 Eligible			$ 139,719	$ 271,055	$ 254,792	$ 239,504	$ 225,134	$ 211,626	$ 198,928	$ 186,993	$ 175,773	$ 165,227
Total Eligible CCA			$ 5,270,736	$ 7,995,000	$ 4,166,120	$ 2,234,653	$ 1,254,296	$ 751,477	$ 489,070	$ 348,237	$ 269,334	$ 222,358
Taxable Income			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			26.25%	25.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax			$ 316,427	$ 12,527	-$ 200,929	-$ 366,639	-$ 491,801	-$ 586,456	-$ 658,122	-$ 712,428	-$ 753,580	-$ 784,720
Net Income (after tax)			$ 924,464	$ 62,399	-$ 602,786	-$ 1,099,917	-$ 1,475,404	-$ 1,759,368	-$ 1,974,367	-$ 2,137,283	-$ 2,260,739	-$ 2,354,159
Cash Distributions												
Equity Dividend	at	100%	$ 924,464	$ 62,399	-$ 602,786	-$ 1,099,917	-$ 1,475,404	-$ 1,759,368	-$ 1,974,367	-$ 2,137,283	-$ 2,260,739	-$ 2,354,159
Depreciation			$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191
Future Income Tax Expense			$ 316,427	$ 12,527	-$ 200,929	-$ 366,639	-$ 491,801	-$ 586,456	-$ 658,122	-$ 712,428	-$ 753,580	-$ 784,720
Debt Repayment			-$ 428,569	-$ 458,569	-$ 490,669	-$ 525,016	-$ 561,767	-$ 601,090	-$ 643,167	-$ 688,188	-$ 736,362	-$ 787,907
Equity dividend		-$ 11,712,937	$ 2,166,512	$ 970,548	$ 59,807	-$ 637,382	-$ 1,174,782	-$ 1,592,724	-$ 1,921,466	-$ 2,183,709	-$ 2,396,490	-$ 2,572,595
		31-Dec-11	31-Dec-12	31-Dec-13	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21
Equity ROE		#DIV/0!										

Industrial scenario	11	12	13	14	15	16	17	18	19	20
Revenu	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Biomethane price sub treshold	18.18	18.31	18.43	18.55	18.68	18.81	18.93	19.06	19.19	19.32
Biomethane price above treshold	11.77	11.84	11.92	12.01	12.09	12.17	12.25	12.33	12.42	12.50
Biomethane	$ 2,214,759	$ 2,229,709	$ 2,244,760	$ 2,259,912	$ 2,275,166	$ 2,290,524	$ 2,305,985	$ 2,321,550	$ 2,337,220	$ 2,352,997
Gate fees	$ 258,197	$ 193,648	$ 145,236	$ 108,927	$ 81,695	$ 61,271	$ 45,954	$ 34,465	$ 25,849	$ 19,387
Total revenues	$ 2,472,957	$ 2,423,357	$ 2,389,996	$ 2,368,839	$ 2,356,861	$ 2,351,795	$ 2,351,938	$ 2,356,015	$ 2,363,069	$ 2,372,383
Production costs										
Production costs	$ 3,536,154	$ 3,615,717	$ 3,697,071	$ 3,780,255	$ 3,865,310	$ 3,952,280	$ 4,041,206	$ 4,132,133	$ 4,225,106	$ 4,320,171
EBITDA	-$ 1,063,197	-$ 1,192,360	-$ 1,307,075	-$ 1,411,416	-$ 1,508,449	-$ 1,600,485	-$ 1,689,268	-$ 1,776,118	-$ 1,862,037	-$ 1,947,788
Depreciation	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191
EBIT	-$ 2,417,387	-$ 2,546,550	-$ 2,661,265	-$ 2,765,606	-$ 2,862,639	-$ 2,954,675	-$ 3,043,459	-$ 3,130,309	-$ 3,216,228	-$ 3,301,978
Total Annual Payment	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428	$ 1,658,428
Principle payment	$ 843,061	$ 902,075	$ 965,220	$ 1,032,785	$ 1,105,080	$ 1,182,436	$ 1,265,206	$ 1,353,771	$ 1,448,535	$ 1,549,932
Interest payment	$ 815,367	$ 756,353	$ 693,208	$ 625,642	$ 553,347	$ 475,992	$ 393,221	$ 304,657	$ 209,893	$ 108,495
Principle Balance	$ 10,805,041	$ 9,902,966	$ 8,937,746	$ 7,904,961	$ 6,799,881	$ 5,617,445	$ 4,352,238	$ 2,998,467	$ 1,549,932	$ -
Net Income (before tax)	-$ 3,232,754	-$ 3,302,903	-$ 3,354,473	-$ 3,391,249	-$ 3,415,987	-$ 3,430,667	-$ 3,436,680	-$ 3,434,965	-$ 3,426,120	-$ 3,410,474
CCA Class 43.2 Factor	*0.0732%*	*0.0366%*	*0.0183%*	*0.0092%*	*0.0046%*	*0.0023%*	*0.0011%*	*0.0006%*	*0.0003%*	*0.0001%*
CCA Class 43.2 Eligible	$ 14,765	$ 7,382	$ 3,691	$ 1,846	$ 923	$ 461	$ 231	$ 115	$ 58	$ 29
CCA Class 8 Factor	*2.4159%*	*1.9327%*	*1.5462%*	*1.2370%*	*0.9896%*	*0.7916%*	*0.6333%*	*0.5067%*	*0.4053%*	*0.3243%*
CCA Class 8 Eligible	$ 22,082	$ 17,665	$ 14,132	$ 11,306	$ 9,045	$ 7,236	$ 5,789	$ 4,631	$ 3,705	$ 2,964
CCA Class 1 Factor	*3.3348%*	*3.1347%*	*2.9467%*	*2.7699%*	*2.6037%*	*2.4474%*	*2.3006%*	*2.1626%*	*2.0328%*	*1.9108%*
CCA Class 1 Eligible	$ 155,313	$ 145,994	$ 137,235	$ 129,001	$ 121,261	$ 113,985	$ 107,146	$ 100,717	$ 94,674	$ 88,994
Total Eligible CCA	$ 192,159	$ 171,042	$ 155,058	$ 142,152	$ 131,228	$ 121,682	$ 113,165	$ 105,463	$ 98,436	$ 91,986
Taxable Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax	-$ 808,189	-$ 825,726	-$ 838,618	-$ 847,812	-$ 853,997	-$ 857,667	-$ 859,170	-$ 858,741	-$ 856,530	-$ 852,618
Net Income (after tax)	-$ 2,424,566	-$ 2,477,177	-$ 2,515,855	-$ 2,543,436	-$ 2,561,990	-$ 2,573,000	-$ 2,577,510	-$ 2,576,224	-$ 2,569,590	-$ 2,557,855
Cash Distributions										
Equity Dividend	-$ 2,424,566	-$ 2,477,177	-$ 2,515,855	-$ 2,543,436	-$ 2,561,990	-$ 2,573,000	-$ 2,577,510	-$ 2,576,224	-$ 2,569,590	-$ 2,557,855
Depreciation	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191	$ 1,354,191
Future Income Tax Expense	-$ 808,189	-$ 825,726	-$ 838,618	-$ 847,812	-$ 853,997	-$ 857,667	-$ 859,170	-$ 858,741	-$ 856,530	-$ 852,618
Debt Repayment	-$ 843,061	-$ 902,075	-$ 965,220	-$ 1,032,785	-$ 1,105,080	-$ 1,182,436	-$ 1,265,206	-$ 1,353,771	-$ 1,448,535	-$ 1,549,932
Equity dividend	-$ 2,721,624	-$ 2,850,787	-$ 2,965,502	-$ 3,069,843	-$ 3,166,877	-$ 3,258,912	-$ 3,347,696	-$ 3,434,546	-$ 3,520,465	-$ 3,606,215
	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31
Equity ROE										

WWTP scenario			1	2	3	4	5	6	7	8	9	10
Revenu			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Biomethane price sub treshold			17.00	17.11	17.23	17.35	17.46	17.58	17.70	17.82	17.94	18.06
Biomethane price above treshold			11.00	11.07	11.15	11.22	11.30	11.38	11.45	11.53	11.61	11.69
Biomethane	$/GJ		$ 388,118	$ 390,738	$ 393,376	$ 396,031	$ 398,704	$ 401,395	$ 404,105	$ 406,833	$ 409,579	$ 412,343
Total revenues			$ 388,118	$ 390,738	$ 393,376	$ 396,031	$ 398,704	$ 401,395	$ 404,105	$ 406,833	$ 409,579	$ 412,343
Production costs												
Production costs			$ 197,647	$ 202,094	$ 206,641	$ 211,291	$ 216,045	$ 220,906	$ 225,876	$ 230,959	$ 236,155	$ 241,469
EBITDA			$ 190,471	$ 188,644	$ 186,734	$ 184,740	$ 182,659	$ 180,489	$ 178,228	$ 175,874	$ 173,424	$ 170,875
Depreciation			$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197
EBIT			$ 71,274	$ 69,447	$ 67,537	$ 65,543	$ 63,462	$ 61,293	$ 59,032	$ 56,677	$ 54,227	$ 51,678
Total Annual Payment			$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318
Principle payment			$ 63,572	$ 66,433	$ 69,422	$ 72,546	$ 75,811	$ 79,222	$ 82,787	$ 86,513	$ 90,406	$ 94,474
Interest payment			$ 89,746	$ 86,885	$ 83,895	$ 80,771	$ 77,507	$ 74,095	$ 70,530	$ 66,805	$ 62,912	$ 58,844
Principle Balance		$ 1,994,348	$ 1,930,776	$ 1,864,343	$ 1,794,921	$ 1,722,374	$ 1,646,563	$ 1,567,341	$ 1,484,553	$ 1,398,041	$ 1,307,635	$ 1,213,160
Net Income (before tax)			-$ 18,471	-$ 17,438	-$ 16,358	-$ 15,228	-$ 14,044	-$ 12,803	-$ 11,499	-$ 10,128	-$ 8,685	-$ 7,166
CCA Class 43.2 Factor		*100.0%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*	*0.2930%*	*0.1465%*
CCA Class 43.2 Eligible			$ 434,250	$ 651,375	$ 325,688	$ 162,844	$ 81,422	$ 40,711	$ 20,355	$ 10,178	$ 5,089	$ 2,544
CCA Class 8 Factor		*100.0%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*	*3.7749%*	*3.0199%*
CCA Class 8 Eligible			$ 13,100	$ 23,580	$ 18,864	$ 15,091	$ 12,073	$ 9,658	$ 7,727	$ 6,181	$ 4,945	$ 3,956
CCA Class 1 Factor		*100.0%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*	*3.7741%*	*3.5477%*
CCA Class 1 Eligible			$ 13,948	$ 27,059	$ 25,435	$ 23,909	$ 22,475	$ 21,126	$ 19,859	$ 18,667	$ 17,547	$ 16,494
Total Eligible CCA			$ 461,298	$ 702,014	$ 369,987	$ 201,844	$ 115,970	$ 71,496	$ 47,941	$ 35,026	$ 27,581	$ 22,995
Taxable Income			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			26.25%	25.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax			-$ 4,710	-$ 4,267	-$ 4,089	-$ 3,807	-$ 3,511	-$ 3,201	-$ 2,875	-$ 2,532	-$ 2,171	-$ 1,791
Net Income (after tax)			-$ 13,761	-$ 13,171	-$ 12,268	-$ 11,421	-$ 10,533	-$ 9,602	-$ 8,624	-$ 7,596	-$ 6,514	-$ 5,374
Cash Distributions												
Equity Dividend	at	100%	-$ 13,761	-$ 13,171	-$ 12,268	-$ 11,421	-$ 10,533	-$ 9,602	-$ 8,624	-$ 7,596	-$ 6,514	-$ 5,374
Depreciation			$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197
Future Income Tax Expense			-$ 4,710	-$ 4,267	-$ 4,089	-$ 3,807	-$ 3,511	-$ 3,201	-$ 2,875	-$ 2,532	-$ 2,171	-$ 1,791
Debt Repayment			-$ 63,572	-$ 66,433	-$ 69,422	-$ 72,546	-$ 75,811	-$ 79,222	-$ 82,787	-$ 86,513	-$ 90,406	-$ 94,474
Equity dividend		-$ 498,587	**$ 37,153**	**$ 35,326**	**$ 33,416**	**$ 31,422**	**$ 29,341**	**$ 27,172**	**$ 24,911**	**$ 22,556**	**$ 20,106**	**$ 17,557**
		31-Dec-11	31-Dec-12	31-Dec-13	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21
Equity ROE		#NUM!										

WWTP scenario	11	12	13	14	15	16	17	18	19	20
Revenu	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Biomethane price sub treshold	18.18	18.31	18.43	18.55	18.68	18.81	18.93	19.06	19.19	19.32
Biomethane price above treshold	11.77	11.84	11.92	12.01	12.09	12.17	12.25	12.33	12.42	12.50
Biomethane	$ 415,127	$ 417,929	$ 420,750	$ 423,590	$ 426,449	$ 429,328	$ 432,226	$ 435,143	$ 438,080	$ 441,037
Total revenues	$ 415,127	$ 417,929	$ 420,750	$ 423,590	$ 426,449	$ 429,328	$ 432,226	$ 435,143	$ 438,080	$ 441,037
Production costs										
Production costs	$ 246,902	$ 252,457	$ 258,137	$ 263,945	$ 269,884	$ 275,957	$ 282,166	$ 288,514	$ 295,006	$ 301,643
EBITDA	$ 168,225	$ 165,472	$ 162,613	$ 159,644	$ 156,565	$ 153,371	$ 150,060	$ 146,629	$ 143,074	$ 139,394
Depreciation	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197
EBIT	$ 49,028	$ 46,275	$ 43,416	$ 40,448	$ 37,368	$ 34,174	$ 30,863	$ 27,432	$ 23,878	$ 20,197
Total Annual Payment	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318	$ 153,318
Principle payment	$ 98,726	$ 103,168	$ 107,811	$ 112,662	$ 117,732	$ 123,030	$ 128,566	$ 134,352	$ 140,398	$ 146,716
Interest payment	$ 54,592	$ 50,150	$ 45,507	$ 40,656	$ 35,586	$ 30,288	$ 24,751	$ 18,966	$ 12,920	$ 6,602
Principle Balance	$ 1,114,435	$ 1,011,267	$ 903,456	$ 790,794	$ 673,061	$ 550,031	$ 421,465	$ 287,113	$ 146,716	-$ 0
Net Income (before tax)	-$ 5,564	-$ 3,875	-$ 2,091	-$ 208	$ 1,782	$ 3,887	$ 6,112	$ 8,466	$ 10,958	$ 13,595
CCA Class 43.2 Factor	*0.0732%*	*0.0366%*	*0.0183%*	*0.0092%*	*0.0046%*	*0.0023%*	*0.0011%*	*0.0006%*	*0.0003%*	*0.0001%*
CCA Class 43.2 Eligible	$ 1,272	$ 636	$ 318	$ 159	$ 80	$ 40	$ 20	$ 10	$ 5	$ 2
CCA Class 8 Factor	*2.4159%*	*1.9327%*	*1.5462%*	*1.2370%*	*0.9896%*	*0.7916%*	*0.6333%*	*0.5067%*	*0.4053%*	*0.3243%*
CCA Class 8 Eligible	$ 3,165	$ 2,532	$ 2,026	$ 1,620	$ 1,296	$ 1,037	$ 830	$ 664	$ 531	$ 425
CCA Class 1 Factor	*3.3348%*	*3.1347%*	*2.9467%*	*2.7699%*	*2.6037%*	*2.4474%*	*2.3006%*	*2.1626%*	*2.0328%*	*1.9108%*
CCA Class 1 Eligible	$ 15,505	$ 14,574	$ 13,700	$ 12,878	$ 12,105	$ 11,379	$ 10,696	$ 10,054	$ 9,451	$ 8,884
Total Eligible CCA	$ 19,942	$ 17,742	$ 16,043	$ 14,657	$ 13,481	$ 12,456	$ 11,546	$ 10,728	$ 9,987	$ 9,311
Taxable Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 93,133
	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax	-$ 1,391	-$ 969	-$ 523	-$ 52	$ 446	$ 972	$ 1,528	$ 2,117	$ 2,739	$ 3,399
Net Income (after tax)	-$ 4,173	-$ 2,906	-$ 1,568	-$ 156	$ 1,337	$ 2,915	$ 4,584	$ 6,350	$ 8,218	$ 10,196
Cash Distributions										
Equity Dividend	-$ 4,173	-$ 2,906	-$ 1,568	-$ 156	$ 1,337	$ 2,915	$ 4,584	$ 6,350	$ 8,218	$ 10,196
Depreciation	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197	$ 119,197
Future Income Tax Expense	-$ 1,391	-$ 969	-$ 523	-$ 52	$ 446	$ 972	$ 1,528	$ 2,117	$ 2,739	-$ 19,885
Debt Repayment	-$ 98,726	-$ 103,168	-$ 107,811	-$ 112,662	-$ 117,732	-$ 123,030	-$ 128,566	-$ 134,352	-$ 140,398	-$ 146,716
Equity dividend	**$ 14,907**	**$ 12,154**	**$ 9,295**	**$ 6,327**	**$ 3,247**	**$ 53**	**-$ 3,258**	**-$ 6,689**	**-$ 10,243**	**-$ 37,207**
	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31
Equity ROE										

Small LF scenario			1	2	3	4	5	6	7	8	9	10
Revenu			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Biomethane price sub treshold			13.00	13.09	13.18	13.27	13.35	13.44	13.54	13.63	13.72	13.81
Biomethane price above treshold			6.00	6.04	6.08	6.12	6.16	6.21	6.25	6.29	6.33	6.37
Biomethane	$/GJ		$ 1,052,209	$ 1,088,947	$ 1,124,821	$ 1,159,866	$ 1,194,117	$ 1,227,607	$ 1,260,368	$ 1,292,431	$ 1,323,826	$ 1,354,581
Total revenues			$ 1,052,209	$ 1,088,947	$ 1,124,821	$ 1,159,866	$ 1,194,117	$ 1,227,607	$ 1,260,368	$ 1,292,431	$ 1,323,826	$ 1,354,581
Production costs												
Production costs			$ 560,753	$ 581,436	$ 602,403	$ 623,664	$ 645,231	$ 667,113	$ 689,321	$ 711,868	$ 734,763	$ 758,019
EBITDA			$ 491,455	$ 507,511	$ 522,418	$ 536,202	$ 548,886	$ 560,494	$ 571,046	$ 580,563	$ 589,062	$ 596,562
Depreciation			$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917
EBIT			$ 247,538	$ 263,594	$ 278,501	$ 292,285	$ 304,969	$ 316,577	$ 327,129	$ 336,646	$ 345,145	$ 352,645
Total Annual Payment			$ 287,576	$ 287,576	$ 287,576	$ 287,576	$ 287,576	$ 287,576	$ 287,576	$ 287,576	$ 287,576	$ 287,576
Principle payment			$ 74,315	$ 79,517	$ 85,083	$ 91,039	$ 97,412	$ 104,231	$ 111,527	$ 119,334	$ 127,687	$ 136,625
Interest payment			$ 213,261	$ 208,059	$ 202,493	$ 196,537	$ 190,164	$ 183,345	$ 176,049	$ 168,242	$ 159,889	$ 150,951
Principle Balance		$ 3,046,588	$ 2,972,273	$ 2,892,756	$ 2,807,672	$ 2,716,633	$ 2,619,221	$ 2,514,990	$ 2,403,463	$ 2,284,129	$ 2,156,442	$ 2,019,816
Net Income (before tax)			$ 34,277	$ 55,535	$ 76,008	$ 95,748	$ 114,805	$ 133,231	$ 151,080	$ 168,403	$ 185,256	$ 201,694
CCA Class 43.2 Factor		*100.0%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*	*0.2930%*	*0.1465%*
CCA Class 43.2 Eligible			$ 995,925	$ 1,493,888	$ 746,944	$ 373,472	$ 186,736	$ 93,368	$ 46,684	$ 23,342	$ 11,671	$ 5,835
CCA Class 8 Factor		*100.0%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*	*3.7749%*	*3.0199%*
CCA Class 8 Eligible			$ 22,200	$ 39,960	$ 31,968	$ 25,574	$ 20,460	$ 16,368	$ 13,094	$ 10,475	$ 8,380	$ 6,704
CCA Class 1 Factor		*100.0%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*	*3.7741%*	*3.5477%*
CCA Class 1 Eligible			$ 16,550	$ 32,108	$ 30,181	$ 28,370	$ 26,668	$ 25,068	$ 23,564	$ 22,150	$ 20,821	$ 19,572
Total Eligible CCA			$ 1,034,675	$ 1,565,955	$ 809,093	$ 427,417	$ 233,864	$ 134,804	$ 83,342	$ 55,967	$ 40,872	$ 32,112
Taxable Income			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			26.25%	25.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax			$ 8,741	$ 13,712	$ 19,002	$ 23,937	$ 28,701	$ 33,308	$ 37,770	$ 42,101	$ 46,314	$ 50,423
Net Income (after tax)			$ 25,536	$ 41,822	$ 57,006	$ 71,811	$ 86,104	$ 99,923	$ 113,310	$ 126,302	$ 138,942	$ 151,270
Cash Distributions												
Equity Dividend	at	100%	$ 25,536	$ 41,822	$ 57,006	$ 71,811	$ 86,104	$ 99,923	$ 113,310	$ 126,302	$ 138,942	$ 151,270
Depreciation			$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917
Future Income Tax Expense			$ 8,741	$ 13,712	$ 19,002	$ 23,937	$ 28,701	$ 33,308	$ 37,770	$ 42,101	$ 46,314	$ 50,423
Debt Repayment			-$ 74,315	-$ 79,517	-$ 85,083	-$ 91,039	-$ 97,412	-$ 104,231	-$ 111,527	-$ 119,334	-$ 127,687	-$ 136,625
Equity dividend		-$ 2,031,059	**$ 203,879**	**$ 219,935**	**$ 234,842**	**$ 248,626**	**$ 261,310**	**$ 272,918**	**$ 283,470**	**$ 292,987**	**$ 301,486**	**$ 308,986**
		31-Dec-11	31-Dec-12	31-Dec-13	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21
Equity ROE		10.52%										

Small LF scenario	11	12	13	14	15	16	17	18	19	20
Revenu	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Biomethane price sub treshold	13.90	14.00	14.09	14.19	14.28	14.38	14.48	14.58	14.67	14.77
Biomethane price above treshold	6.42	6.46	6.50	6.55	6.59	6.64	6.68	6.73	6.77	6.82
Biomethane	$ 1,384,725	$ 1,414,284	$ 1,443,284	$ 1,471,748	$ 1,499,702	$ 1,527,168	$ 1,554,168	$ 1,580,723	$ 1,606,855	$ 1,632,582
Total revenues	$ 1,384,725	$ 1,414,284	$ 1,443,284	$ 1,471,748	$ 1,499,702	$ 1,527,168	$ 1,554,168	$ 1,580,723	$ 1,606,855	$ 1,632,582
Production costs										
Production costs	$ 781,647	$ 805,659	$ 830,067	$ 854,882	$ 880,118	$ 905,786	$ 931,900	$ 958,473	$ 985,518	$ 1,013,905
EBITDA	$ 603,078	$ 608,625	$ 613,217	$ 616,866	$ 619,584	$ 621,382	$ 622,267	$ 622,250	$ 621,337	$ 618,677
Depreciation	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917
EBIT	$ 359,161	$ 364,708	$ 369,300	$ 372,949	$ 375,667	$ 377,464	$ 378,350	$ 378,333	$ 377,420	$ 374,760
Total Annual Payment	$ 287,576	$ 287,576	$ 287,576	$ 287,576	$ 287,576	$ 287,576	$ 287,576	$ 287,576	$ 287,576	$ 287,576
Principle payment	$ 146,189	$ 156,422	$ 167,372	$ 179,088	$ 191,624	$ 205,038	$ 219,391	$ 234,748	$ 251,180	$ 268,763
Interest payment	$ 141,387	$ 131,154	$ 120,204	$ 108,488	$ 95,952	$ 82,538	$ 68,186	$ 52,828	$ 36,396	$ 18,813
Principle Balance	$ 1,873,627	$ 1,717,204	$ 1,549,832	$ 1,370,744	$ 1,179,120	$ 974,082	$ 754,691	$ 519,943	$ 268,763	-$ 0
Net Income (before tax)	$ 217,774	$ 233,554	$ 249,095	$ 264,461	$ 279,715	$ 294,926	$ 310,164	$ 325,505	$ 341,024	$ 355,946
CCA Class 43.2 Factor	*0.0732%*	*0.0366%*	*0.0183%*	*0.0092%*	*0.0046%*	*0.0023%*	*0.0011%*	*0.0006%*	*0.0003%*	*0.0001%*
CCA Class 43.2 Eligible	$ 2,918	$ 1,459	$ 729	$ 365	$ 182	$ 91	$ 46	$ 23	$ 11	$ 6
CCA Class 8 Factor	*2.4159%*	*1.9327%*	*1.5462%*	*1.2370%*	*0.9896%*	*0.7916%*	*0.6333%*	*0.5067%*	*0.4053%*	*0.3243%*
CCA Class 8 Eligible	$ 5,363	$ 4,291	$ 3,433	$ 2,746	$ 2,197	$ 1,757	$ 1,406	$ 1,125	$ 900	$ 720
CCA Class 1 Factor	*3.3348%*	*3.1347%*	*2.9467%*	*2.7699%*	*2.6037%*	*2.4474%*	*2.3006%*	*2.1626%*	*2.0328%*	*1.9108%*
CCA Class 1 Eligible	$ 18,398	$ 17,294	$ 16,256	$ 15,281	$ 14,364	$ 13,502	$ 12,692	$ 11,930	$ 11,215	$ 10,542
Total Eligible CCA	$ 26,679	$ 23,043	$ 20,418	$ 18,391	$ 16,743	$ 15,351	$ 14,143	$ 13,078	$ 12,126	$ 11,267
Taxable Income	$ -	$ 126,548	$ 472,595	$ 489,986	$ 506,889	$ 523,492	$ 539,938	$ 556,344	$ 572,815	$ 588,596
	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax	$ 54,443	$ 58,388	$ 62,274	$ 66,115	$ 69,929	$ 73,731	$ 77,541	$ 81,376	$ 85,256	$ 88,987
Net Income (after tax)	$ 163,330	$ 175,165	$ 186,821	$ 198,345	$ 209,786	$ 221,194	$ 232,623	$ 244,128	$ 255,768	$ 266,960
Cash Distributions										
Equity Dividend	$ 163,330	$ 175,165	$ 186,821	$ 198,345	$ 209,786	$ 221,194	$ 232,623	$ 244,128	$ 255,768	$ 266,960
Depreciation	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917	$ 243,917
Future Income Tax Expense	$ 54,443	$ 26,751	-$ 55,875	-$ 56,381	-$ 56,794	-$ 57,142	-$ 57,443	-$ 57,710	-$ 57,948	-$ 58,163
Debt Repayment	-$ 146,189	-$ 156,422	-$ 167,372	-$ 179,088	-$ 191,624	-$ 205,038	-$ 219,391	-$ 234,748	-$ 251,180	-$ 268,763
Equity dividend	**$ 315,502**	**$ 289,412**	**$ 207,492**	**$ 206,793**	**$ 205,286**	**$ 202,932**	**$ 199,707**	**$ 195,588**	**$ 190,557**	**$ 183,952**
	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31

Medium LF scenario			1	2	3	4	5	6	7	8	9	10
Revenu			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Biomethane price sub treshold			13.00	13.09	13.18	13.27	13.35	13.44	13.54	13.63	13.72	13.81
Biomethane price above treshold			6.00	6.04	6.08	6.12	6.16	6.21	6.25	6.29	6.33	6.37
Biomethane	$/GJ		$ 2,183,148	$ 2,229,800	$ 2,275,569	$ 2,320,493	$ 2,364,610	$ 2,407,957	$ 2,450,568	$ 2,492,477	$ 2,533,716	$ 2,574,317
Total revenues			$ 2,183,148	$ 2,229,800	$ 2,275,569	$ 2,320,493	$ 2,364,610	$ 2,407,957	$ 2,450,568	$ 2,492,477	$ 2,533,716	$ 2,574,317
Production costs												
Production costs			$ 1,073,264	$ 1,116,205	$ 1,159,689	$ 1,203,739	$ 1,248,375	$ 1,293,621	$ 1,339,500	$ 1,386,033	$ 1,433,245	$ 1,481,158
EBITDA			$ 1,109,884	$ 1,113,595	$ 1,115,880	$ 1,116,755	$ 1,116,235	$ 1,114,336	$ 1,111,068	$ 1,106,444	$ 1,100,471	$ 1,093,159
Depreciation			$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152
EBIT			$ 664,732	$ 668,443	$ 670,728	$ 671,603	$ 671,083	$ 669,184	$ 665,916	$ 661,292	$ 655,319	$ 648,007
Total Annual Payment			$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784
Principle payment			$ 133,288	$ 142,619	$ 152,602	$ 163,284	$ 174,714	$ 186,944	$ 200,030	$ 214,032	$ 229,014	$ 245,045
Interest payment			$ 382,496	$ 373,166	$ 363,182	$ 352,500	$ 341,070	$ 328,840	$ 315,754	$ 301,752	$ 286,770	$ 270,739
Principle Balance		$ 5,464,225	$ 5,330,936	$ 5,188,318	$ 5,035,716	$ 4,872,432	$ 4,697,718	$ 4,510,774	$ 4,310,744	$ 4,096,712	$ 3,867,697	$ 3,622,652
Net Income (before tax)			$ 282,236	$ 295,278	$ 307,546	$ 319,102	$ 330,013	$ 340,343	$ 350,162	$ 359,540	$ 368,550	$ 377,268
CCA Class 43.2 Factor		*100.0%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*	*0.2930%*	*0.1465%*
CCA Class 43.2 Eligible			$ 1,560,500	$ 2,340,750	$ 1,170,375	$ 585,188	$ 292,594	$ 146,297	$ 73,148	$ 36,574	$ 18,287	$ 9,144
CCA Class 8 Factor		*100.0%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*	*3.7749%*	*3.0199%*
CCA Class 8 Eligible			$ 32,700	$ 58,860	$ 47,088	$ 37,670	$ 30,136	$ 24,109	$ 19,287	$ 15,430	$ 12,344	$ 9,875
CCA Class 1 Factor		*100.0%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*	*3.7741%*	*3.5477%*
CCA Class 1 Eligible			$ 63,512	$ 123,214	$ 115,821	$ 108,872	$ 102,340	$ 96,199	$ 90,427	$ 85,002	$ 79,902	$ 75,107
Total Eligible CCA			$ 1,656,712	$ 2,522,824	$ 1,333,284	$ 731,730	$ 425,070	$ 266,605	$ 182,863	$ 137,006	$ 110,533	$ 94,126
Taxable Income			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 320,805
			26.25%	25.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax			$ 71,970	$ 72,408	$ 76,886	$ 79,776	$ 82,503	$ 85,086	$ 87,541	$ 89,885	$ 92,137	$ 94,317
Net Income (after tax)			$ 210,266	$ 222,870	$ 230,659	$ 239,327	$ 247,510	$ 255,258	$ 262,622	$ 269,655	$ 276,412	$ 282,951
Cash Distributions												
Equity Dividend	at	100%	$ 210,266	$ 222,870	$ 230,659	$ 239,327	$ 247,510	$ 255,258	$ 262,622	$ 269,655	$ 276,412	$ 282,951
Depreciation			$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152
Future Income Tax Expense			$ 71,970	$ 72,408	$ 76,886	$ 79,776	$ 82,503	$ 85,086	$ 87,541	$ 89,885	$ 92,137	$ 14,116
Debt Repayment			-$ 133,288	-$ 142,619	-$ 152,602	-$ 163,284	-$ 174,714	-$ 186,944	-$ 200,030	-$ 214,032	-$ 229,014	-$ 245,045
Equity dividend		-$ 3,642,816	**$ 594,100**	**$ 597,811**	**$ 600,096**	**$ 600,970**	**$ 600,451**	**$ 598,552**	**$ 595,284**	**$ 590,660**	**$ 584,687**	**$ 497,173**
		31-Dec-11	31-Dec-12	31-Dec-13	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21
Equity ROE		13.44%										

Medium LF scenario	11	12	13	14	15	16	17	18	19	20
Revenu	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Biomethane price sub treshold	13.90	14.00	14.09	14.19	14.28	14.38	14.48	14.58	14.67	14.77
Biomethane price above treshold	6.42	6.46	6.50	6.55	6.59	6.64	6.68	6.73	6.77	6.82
Biomethane	$ 2,614,310	$ 2,653,723	$ 2,692,585	$ 2,730,923	$ 2,768,762	$ 2,806,128	$ 2,843,045	$ 2,879,536	$ 2,915,624	$ 2,951,330
Total revenues	$ 2,614,310	$ 2,653,723	$ 2,692,585	$ 2,730,923	$ 2,768,762	$ 2,806,128	$ 2,843,045	$ 2,879,536	$ 2,915,624	$ 2,951,330
Production costs										
Production costs	$ 1,529,797	$ 1,579,186	$ 1,629,350	$ 1,680,313	$ 1,732,102	$ 1,784,740	$ 1,838,256	$ 1,892,676	$ 1,948,026	$ 2,004,285
EBITDA	$ 1,084,512	$ 1,074,536	$ 1,063,235	$ 1,050,609	$ 1,036,660	$ 1,021,388	$ 1,004,789	$ 986,860	$ 967,598	$ 947,046
Depreciation	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152
EBIT	$ 639,360	$ 629,384	$ 618,083	$ 605,457	$ 591,508	$ 576,236	$ 559,637	$ 541,708	$ 522,446	$ 501,894
Total Annual Payment	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784	$ 515,784
Principle payment	$ 262,199	$ 280,552	$ 300,191	$ 321,204	$ 343,689	$ 367,747	$ 393,489	$ 421,034	$ 450,506	$ 482,041
Interest payment	$ 253,586	$ 235,232	$ 215,593	$ 194,580	$ 172,095	$ 148,037	$ 122,295	$ 94,751	$ 65,278	$ 33,743
Principle Balance	$ 3,360,454	$ 3,079,901	$ 2,779,710	$ 2,458,506	$ 2,114,817	$ 1,747,070	$ 1,353,581	$ 932,547	$ 482,041	-$ 0
Net Income (before tax)	$ 385,775	$ 394,153	$ 402,490	$ 410,878	$ 419,413	$ 428,198	$ 437,342	$ 446,958	$ 457,168	$ 468,151
CCA Class 43.2 Factor	*0.0732%*	*0.0366%*	*0.0183%*	*0.0092%*	*0.0046%*	*0.0023%*	*0.0011%*	*0.0006%*	*0.0003%*	*0.0001%*
CCA Class 43.2 Eligible	$ 4,572	$ 2,286	$ 1,143	$ 571	$ 286	$ 143	$ 71	$ 36	$ 18	$ 9
CCA Class 8 Factor	*2.4159%*	*1.9327%*	*1.5462%*	*1.2370%*	*0.9896%*	*0.7916%*	*0.6333%*	*0.5067%*	*0.4053%*	*0.3243%*
CCA Class 8 Eligible	$ 7,900	$ 6,320	$ 5,056	$ 4,045	$ 3,236	$ 2,589	$ 2,071	$ 1,657	$ 1,325	$ 1,060
CCA Class 1 Factor	*3.3348%*	*3.1347%*	*2.9467%*	*2.7699%*	*2.6037%*	*2.4474%*	*2.3006%*	*2.1626%*	*2.0328%*	*1.9108%*
CCA Class 1 Eligible	$ 70,601	$ 66,365	$ 62,383	$ 58,640	$ 55,122	$ 51,814	$ 48,706	$ 45,783	$ 43,036	$ 40,454
Total Eligible CCA	$ 83,073	$ 74,971	$ 68,582	$ 63,256	$ 58,643	$ 54,546	$ 50,848	$ 47,476	$ 44,379	$ 41,523
Taxable Income	$ 747,854	$ 764,334	$ 779,060	$ 792,773	$ 805,922	$ 818,805	$ 831,646	$ 844,634	$ 857,940	$ 871,780
	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax	$ 96,444	$ 98,538	$ 100,622	$ 102,719	$ 104,853	$ 107,050	$ 109,335	$ 111,739	$ 114,292	$ 117,038
Net Income (after tax)	$ 289,331	$ 295,615	$ 301,867	$ 308,158	$ 314,560	$ 321,149	$ 328,006	$ 335,218	$ 342,876	$ 351,113
Cash Distributions										
Equity Dividend	$ 289,331	$ 295,615	$ 301,867	$ 308,158	$ 314,560	$ 321,149	$ 328,006	$ 335,218	$ 342,876	$ 351,113
Depreciation	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152	$ 445,152
Future Income Tax Expense	-$ 90,520	-$ 92,545	-$ 94,143	-$ 95,474	-$ 96,627	-$ 97,652	-$ 98,576	-$ 99,419	-$ 100,193	-$ 100,907
Debt Repayment	-$ 262,199	-$ 280,552	-$ 300,191	-$ 321,204	-$ 343,689	-$ 367,747	-$ 393,489	-$ 421,034	-$ 450,506	-$ 482,041
Equity dividend	**$ 381,765**	**$ 367,669**	**$ 352,686**	**$ 336,632**	**$ 319,396**	**$ 300,902**	**$ 281,093**	**$ 259,918**	**$ 237,329**	**$ 213,317**
	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31

Large LF scenario		1	2	3	4	5	6	7	8	9	10
Revenu		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Biomethane price sub treshold		13.00	13.09	13.18	13.27	13.35	13.44	13.54	13.63	13.72	13.81
Biomethane price above treshold		6.00	6.04	6.08	6.12	6.16	6.21	6.25	6.29	6.33	6.37
Biomethane	$/GJ	$ 4,860,938	$ 5,001,088	$ 5,034,845	$ 5,068,830	$ 5,103,045	$ 5,137,490	$ 5,172,169	$ 5,207,081	$ 5,242,228	$ 5,277,614
Total revenues		$ 4,860,938	$ 5,001,088	$ 5,034,845	$ 5,068,830	$ 5,103,045	$ 5,137,490	$ 5,172,169	$ 5,207,081	$ 5,242,228	$ 5,277,614
Production costs											
Production costs		$ 2,918,321	$ 3,047,042	$ 3,115,601	$ 3,185,702	$ 3,257,380	$ 3,330,671	$ 3,405,611	$ 3,482,237	$ 3,560,588	$ 3,640,701
EBITDA		$ 1,942,617	$ 1,954,046	$ 1,919,245	$ 1,883,129	$ 1,845,665	$ 1,806,820	$ 1,766,558	$ 1,724,843	$ 1,681,641	$ 1,636,913
Depreciation		$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379
EBIT		$ 1,253,238	$ 1,264,667	$ 1,229,866	$ 1,193,750	$ 1,156,286	$ 1,117,441	$ 1,077,179	$ 1,035,465	$ 992,262	$ 947,534
Total Annual Payment		$ 799,843	$ 799,843	$ 799,843	$ 799,843	$ 799,843	$ 799,843	$ 799,843	$ 799,843	$ 799,843	$ 799,843
Principle payment		$ 206,695	$ 221,163	$ 236,645	$ 253,210	$ 270,934	$ 289,900	$ 310,193	$ 331,906	$ 355,140	$ 380,000
Interest payment		$ 593,148	$ 578,680	$ 563,198	$ 546,633	$ 528,908	$ 509,943	$ 489,650	$ 467,937	$ 444,703	$ 419,843
Principle Balance	$ 8,473,547	$ 8,266,853	$ 8,045,689	$ 7,809,045	$ 7,555,835	$ 7,284,901	$ 6,995,001	$ 6,684,808	$ 6,352,901	$ 5,997,762	$ 5,617,762
Net Income (before tax)		$ 660,090	$ 685,987	$ 666,667	$ 647,117	$ 627,378	$ 607,498	$ 587,529	$ 567,528	$ 547,559	$ 527,690
CCA Class 43.2 Factor	*100.0%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*	*0.2930%*	*0.1465%*
CCA Class 43.2 Eligible		$ 2,381,500	$ 3,572,250	$ 1,786,125	$ 893,063	$ 446,531	$ 223,266	$ 111,633	$ 55,816	$ 27,908	$ 13,954
CCA Class 43.2 Factor											
CCA Class 43.2 Eligible											
CCA Class 8 Factor	*100.0%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*	*3.7749%*	*3.0199%*
CCA Class 8 Eligible		$ 40,200	$ 72,360	$ 57,888	$ 46,310	$ 37,048	$ 29,639	$ 23,711	$ 18,969	$ 15,175	$ 12,140
CCA Class 8 Factor											
CCA Class 8 Eligible											
CCA Class 1 Factor	*100.0%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*	*3.7741%*	*3.5477%*
CCA Class 1 Eligible		$ 100,926	$ 195,797	$ 184,049	$ 173,006	$ 162,626	$ 152,868	$ 143,696	$ 135,074	$ 126,970	$ 119,352
CCA Class 1 Factor											
CCA Class 1 Eligible											
Total Eligible CCA		$ 2,522,626	$ 3,840,407	$ 2,028,062	$ 1,112,379	$ 646,205	$ 405,772	$ 279,040	$ 209,859	$ 170,053	$ 145,446
Taxable Income		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 587,359	$ 1,071,624
		26.25%	25.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax		$ 168,323	$ 168,196	$ 166,667	$ 161,779	$ 156,844	$ 151,874	$ 146,882	$ 141,882	$ 136,890	$ 131,923
Net Income (after tax)		$ 491,767	$ 517,791	$ 500,001	$ 485,338	$ 470,533	$ 455,623	$ 440,646	$ 425,646	$ 410,669	$ 395,768
Cash Distributions											
Equity Dividend	at 100%	$ 491,767	$ 517,791	$ 500,001	$ 485,338	$ 470,533	$ 455,623	$ 440,646	$ 425,646	$ 410,669	$ 395,768
Depreciation		$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379	$ 689,379
Future Income Tax Expense		$ 168,323	$ 168,196	$ 166,667	$ 161,779	$ 156,844	$ 151,874	$ 146,882	$ 141,882	-$ 9,950	-$ 135,983
Debt Repayment		-$ 206,695	-$ 221,163	-$ 236,645	-$ 253,210	-$ 270,934	-$ 289,900	-$ 310,193	-$ 331,906	-$ 355,140	-$ 380,000
Equity dividend	-$ 5,649,032	**$ 1,142,774**	**$ 1,154,203**	**$ 1,119,402**	**$ 1,083,286**	**$ 1,045,822**	**$ 1,006,977**	**$ 966,715**	**$ 925,001**	**$ 734,958**	**$ 569,164**
	31-Dec-11	31-Dec-12	31-Dec-13	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21
Equity ROE	13.56%										

Large LF scenario	11	12	13	14	15	16	17	18	19	20
Revenu	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Biomethane price sub treshold	13.90	14.00	14.09	14.19	14.28	14.38	14.48	14.58	14.67	14.77
Biomethane price above treshold	6.42	6.46	6.50	6.55	6.59	6.64	6.68	6.73	6.77	6.82
Biomethane	$ 5,313,237	$ 5,349,102	$ 6,365,631	$ 6,476,409	$ 6,585,389	$ 6,692,653	$ 6,798,283	$ 6,902,356	$ 7,004,947	$ 7,106,127
Total revenues	$ 5,313,237	$ 5,349,102	$ 6,365,631	$ 6,476,409	$ 6,585,389	$ 6,692,653	$ 6,798,283	$ 6,902,356	$ 7,004,947	$ 7,106,127
Production costs										
Production costs	$ 3,722,617	$ 4,048,652	$ 4,645,376	$ 4,788,258	$ 4,947,909	$ 5,109,985	$ 5,274,566	$ 5,441,735	$ 5,611,574	$ 5,784,168
EBITDA	$ 1,590,621	$ 1,300,450	$ 1,720,255	$ 1,688,151	$ 1,637,479	$ 1,582,668	$ 1,523,717	$ 1,460,621	$ 1,393,373	$ 1,321,959
Depreciation	$ 689,379	$ 689,379	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096
EBIT	$ 901,242	$ 611,071	$ 616,160	$ 584,055	$ 533,384	$ 478,572	$ 419,621	$ 356,526	$ 289,278	$ 217,864
Total Annual Payment	$ 799,843	$ 799,843	$ 1,137,410	$ 1,137,410	$ 1,137,410	$ 1,137,410	$ 1,137,410	$ 1,137,410	$ 1,137,410	$ 1,137,410
Principle payment	$ 406,600	$ 435,062	$ 661,983	$ 708,322	$ 757,905	$ 810,958	$ 867,725	$ 928,466	$ 993,458	$ 1,063,000
Interest payment	$ 393,243	$ 364,781	$ 475,427	$ 429,088	$ 379,506	$ 326,453	$ 269,685	$ 208,945	$ 143,952	$ 74,410
Principle Balance	$ 5,211,162	$ 6,791,817	$ 6,129,834	$ 5,421,512	$ 4,663,607	$ 3,852,649	$ 2,984,924	$ 2,056,459	$ 1,063,000	$ 0
Net Income (before tax)	$ 507,999	$ 246,290	$ 140,732	$ 154,967	$ 153,878	$ 152,120	$ 149,936	$ 147,581	$ 145,325	$ 143,454
CCA Class 43.2 Factor	*0.0732%*	*0.0366%*	*0.0183%*	*0.0092%*	*0.0046%*	*0.0023%*	*0.0011%*	*0.0006%*	*0.0003%*	*0.0001%*
CCA Class 43.2 Eligible	$ 6,977	$ 3,489	$ 1,744	$ 872	$ 436	$ 218	$ 109	$ 55	$ 27	$ 14
CCA Class 43.2 Factor		*100.0000%*	*25.0000%*	*37.5000%*	*18.7500%*	*9.3750%*	*4.6875%*	*2.3438%*	*1.1719%*	*0.5859%*
CCA Class 43.2 Eligible			$ 785,916	$ 1,178,873	$ 589,437	$ 294,718	$ 147,359	$ 73,680	$ 36,840	$ 18,420
CCA Class 8 Factor	*2.4159%*	*1.9327%*	*1.5462%*	*1.2370%*	*0.9896%*	*0.7916%*	*0.6333%*	*0.5067%*	*0.4053%*	*0.3243%*
CCA Class 8 Eligible	$ 9,712	$ 7,770	$ 6,216	$ 4,973	$ 3,978	$ 3,182	$ 2,546	$ 2,037	$ 1,629	$ 1,304
CCA Class 8 Factor		*100.0000%*	*10.0000%*	*18.0000%*	*14.4000%*	*11.5200%*	*9.2160%*	*7.3728%*	*5.8982%*	*4.7186%*
CCA Class 8 Eligible			$ 9,404	$ 16,926	$ 13,541	$ 10,833	$ 8,666	$ 6,933	$ 5,546	$ 4,437
CCA Class 1 Factor	*3.3348%*	*3.1347%*	*2.9467%*	*2.7699%*	*2.6037%*	*2.4474%*	*2.3006%*	*2.1626%*	*2.0328%*	*1.9108%*
CCA Class 1 Eligible	$ 112,191	$ 105,459	$ 99,132	$ 93,184	$ 87,593	$ 82,337	$ 77,397	$ 72,753	$ 68,388	$ 64,285
CCA Class 1 Factor		*100.0000%*	*3.0000%*	*5.8200%*	*5.4708%*	*5.1426%*	*4.8340%*	*4.5440%*	*4.2713%*	*4.0150%*
CCA Class 1 Eligible			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Eligible CCA	$ 128,880	$ 116,717	$ 902,411	$ 1,294,828	$ 694,985	$ 391,289	$ 236,077	$ 155,457	$ 112,431	$ 88,459
Taxable Income	$ 1,068,498	$ 818,952	$ 342,417	$ -	$ 527,223	$ 864,927	$ 1,017,954	$ 1,096,220	$ 1,136,990	$ 1,159,091
	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Income Tax	$ 127,000	$ 61,572	$ 35,183	$ 38,742	$ 38,469	$ 38,030	$ 37,484	$ 36,895	$ 36,331	$ 35,863
Net Income (after tax)	$ 380,999	$ 184,717	$ 105,549	$ 116,225	$ 115,408	$ 114,090	$ 112,452	$ 110,686	$ 108,994	$ 107,590
Cash Distributions										
Equity Dividend	$ 380,999	$ 184,717	$ 105,549	$ 116,225	$ 115,408	$ 114,090	$ 112,452	$ 110,686	$ 108,994	$ 107,590
Depreciation	$ 689,379	$ 689,379	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096	$ 1,104,096
Future Income Tax Expense	-$ 140,125	-$ 143,165	-$ 50,421	$ 38,742	-$ 93,336	-$ 178,202	-$ 217,005	-$ 237,160	-$ 247,916	-$ 253,909
Debt Repayment	-$ 406,600	-$ 435,062	-$ 661,983	-$ 708,322	-$ 757,905	-$ 810,958	-$ 867,725	-$ 928,466	-$ 993,458	-$ 1,063,000
Equity dividend	**$ 523,653**	**-$ 1,047,941**	**$ 497,240**	**$ 550,740**	**$ 368,263**	**$ 229,026**	**$ 131,818**	**$ 49,156**	**-$ 28,285**	**-$ 105,224**
	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31

Potential Production of Renewable Natural Gas from Ontario Wastes

By

Salim Abboud and Brent Scorfield
Alberta Innovates Technology Futures

May 2011

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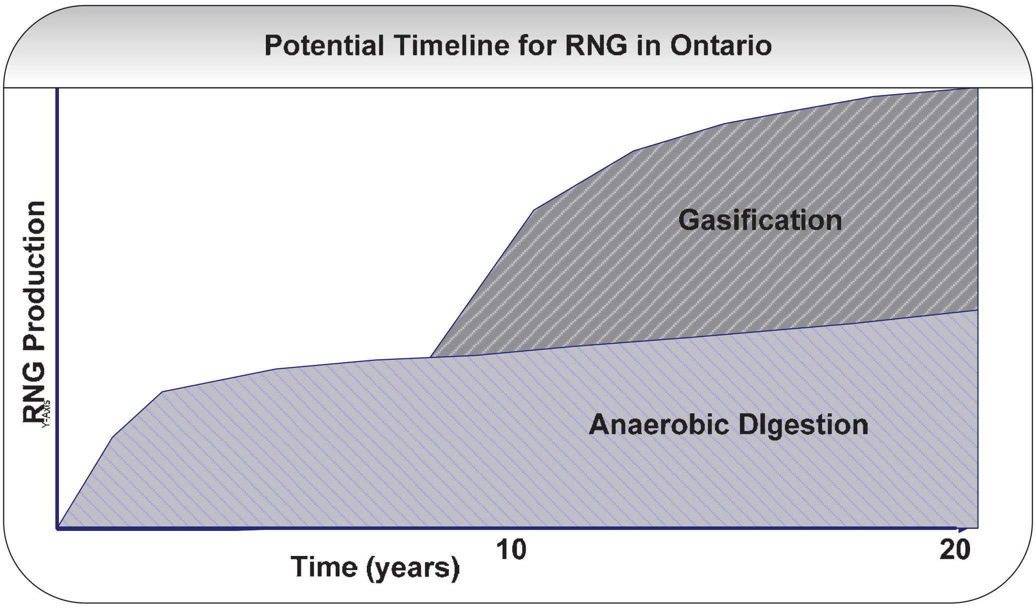
EXECUTIVE SUMMARY

This report evaluates the Ontario waste market potential, and role that these feedstocks can play in producing energy (in the form of methane gas) from waste biomass, which can then be used as a source for renewable natural gas (RNG). Our objective was to conduct a literature based study whose aim will be to assess the potential for methane generation from Ontario wastes, and the relative greenhouse gas (GHG) impacts of capturing the generated methane.

The production of RNG from Ontario wastes, following the separation and cleaning of biogas was shown to arise from the application of two well used and understood processes: Anaerobic Digestion (AD), which produces biogas as landfill gas or through the use of anaerobic digesters, and Gasification. With the main focus of this report the production of methane from Ontario-generated waste biomass, we have narrowed our discussion of AD-produced raw biogas and biosolid-produced raw biosyngas. Based on our findings, it is envisioned that the AD process will be the primary source of RNG in the next 10 years (near-term time horizon) as this technology is already in use. Gasification will contribute beyond 10 years (long-term time horizon) subject to its acceptance by industry and the need for further technology development activities. Within the report, RNG potential production in Ontario is evaluated separately between the near-term (up to 10 year) and long-term (over 10 year) time horizons.



The Ontario wastes which are amenable to producing RNG are those containing significant amounts of biomass and are mostly generated by the agricultural, forestry and municipal sectors.

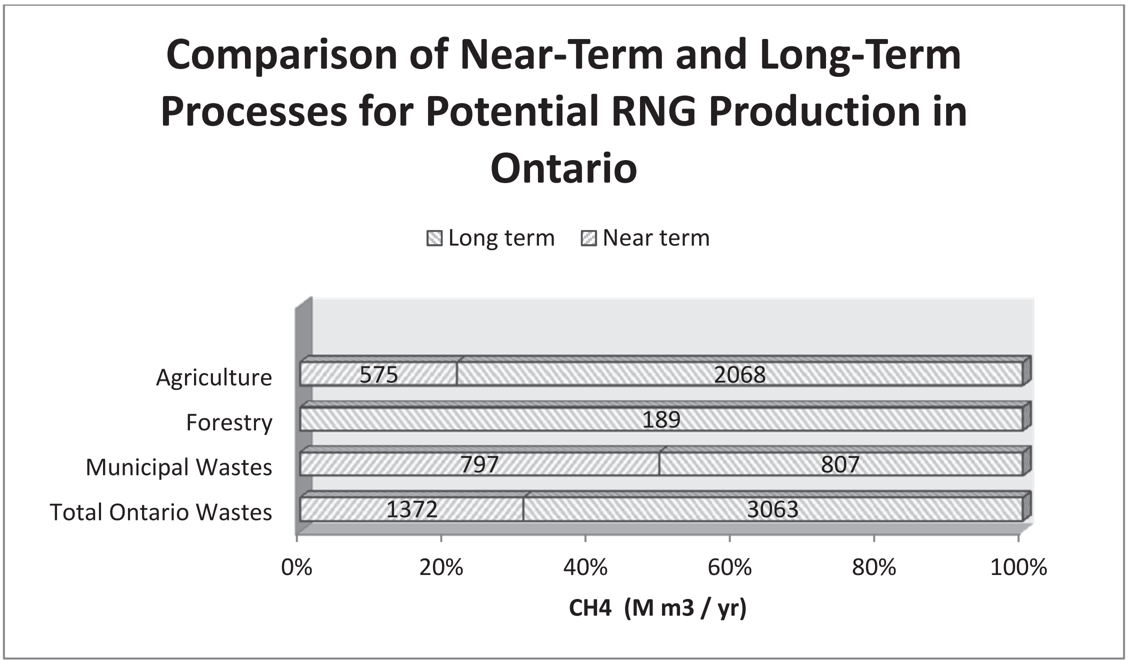
All of the potential RNG that can be produced from the total Ontario wastes that had been reviewed shows that a potential total of 4435 M m^3/yr of RNG can be produced. Agricultural waste has demonstrated the potential to produce 2643 M m^3/yr (60% of total), followed by 1604 M m^3/yr (36%) from municipal wastes and 188 M m^3/yr (4%) from forestry residues. RNG production is also broken out separately for Enbridge and Union Gas and summarized below.

Annual Potential RNG Production from Ontario Wastes

	Agriculture Wastes				Forestry Residues	Municipal Wastes					Total Methane Production
	Manure		Crops			MSW		Landfill	WW	Biosolids	
	Near-Term (AD)	Long-Term (Gas)	Near-Term (AD)	Long-Term (Gas)	Long-Term (Gas)	Near-Term (AD)	Long-Term (Gas)	Near-Term (AD)	Near-Term (AD)	Long-Term (Gas)	
	(M m^3/yr)										
Enbridge	41.2	64	69.1	322	4.85	18.2	297	395	41.5	41.8	1294
Union Gas	156	241	309	1440	184	27.2	441	289	26.6	26.9	3141
Ontario	197	306	378	1762	188	45.4	738	684	68.1	68.7	4435

Note: AD = anaerobic digestion process; Gas = gasification process
MSW = Municipal Solid waste; WW = Wastewater

Anaerobic digestion has the potential to produce 1372 M m^3/yr (31% of total) and represents the near-term potential of all the RNG production in Ontario. The use of gasification has the potential to produce most of the RNG as we estimated that an additional 3063 M m^3/yr (69% of total) can be produced by this process, however this potential would be realized over the long-term through further technology development.



We compared the relative size of our potential RNG estimates to the current natural gas consumption in the residential, commercial and industrial sectors. The potential Ontario generation of 4435 M m^3/yr of RNG (corresponding to an energy value of 167 PJ/yr, assuming 37.69 GJ/10^3m^3, or 46,388 GWh of electricity) could account for a portion of the natural gas consumption. Within Ontario, our estimate is that if all methane from various wastes was captured, then 18% of current NG residential, commercial and industrial use can be replaced by the produced RNG over the long-term. However, in the near-term the potential Ontario generation of 1372 M m^3/yr (with an energy value of 52 PJ/yr, or 14,444 GWh of electricity) of RNG can account for about 6% of the residential, commercial and industrial use of NG. With gasification process capabilities becoming available over the long-term, then there would be an additional 3063 M m^3/yr (with an energy value of 115 PJ/yr, or 31944 GWh of electricity) of RNG, corresponding to an additional 12% of the current NG consumption in Ontario.

Enbridge and Union Gas were evaluated separately for market potential in order to have a better understanding of the allocation of waste sources in Ontario. This data is provided in detail throughout the report, but this information is of secondary importance to the total RNG which is potentially available within Ontario as a whole.

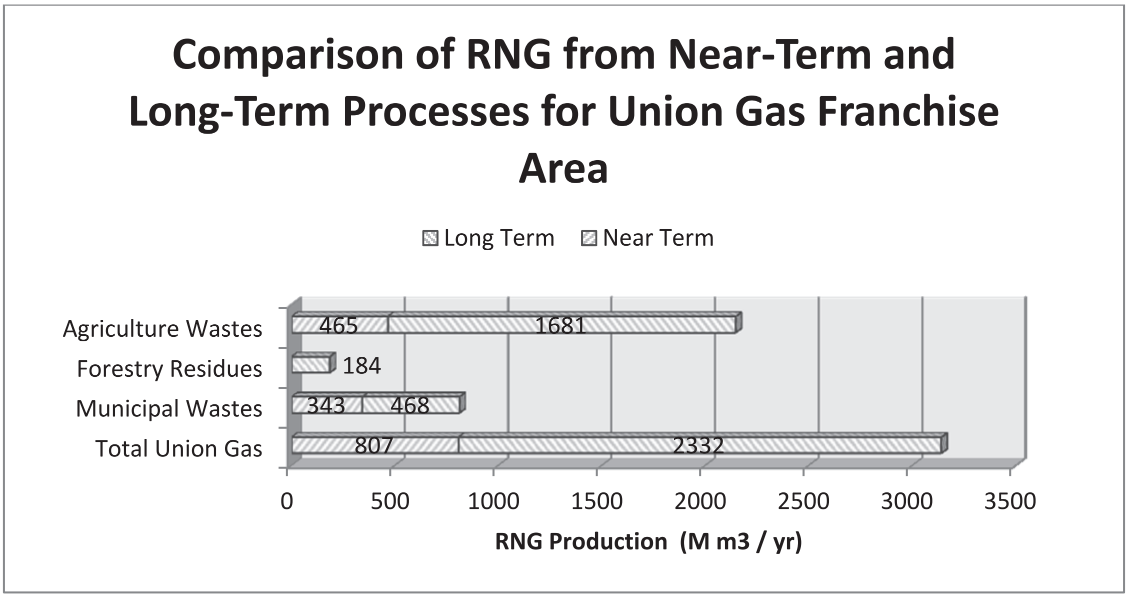
The following approach was used to allocate waste sources to either Enbridge or Union Gas. First, population data was reviewed on a county basis and allocated to either franchise based upon their service area. The ratio of Ontario population per franchise area was used for RNG calculations for all municipal wastes since that waste stream is directly proportional to the number of people residing in the area. Then the other waste materials, including agricultural and forestry residues, had RNG calculations based on Ontario government volume data provided on a county basis, and allocated to either franchise.

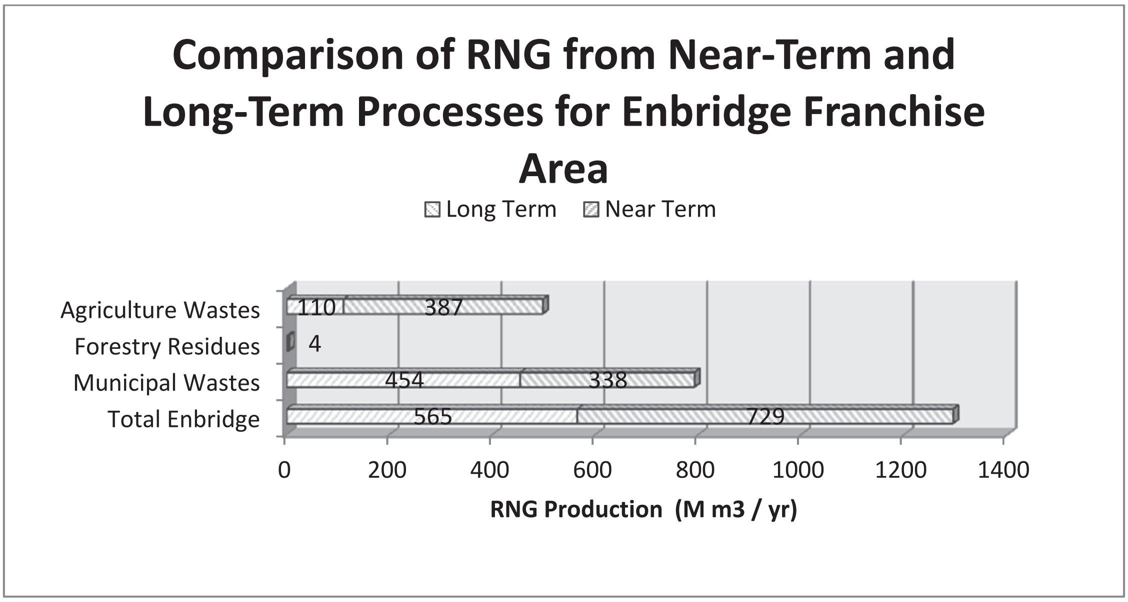
In a limited number of cases, some counties were serviced by both franchises. With these counties, the proportion of population was allocated to either franchise and this ratio was used on the waste volumes for RNG calculations. Additionally, the cities of Kitchener and Kingston operate independent municipal gas utility services. Both Kitchener and Kingston are surrounded by Union Gas' franchise area, as such, potential methane generation from municipal wastes in either location are included in the calculation of Union Gas' total potential.

It was also determined from the franchises' service directory that two Ontario counties (Haliburton, Manitoulin) and a few other small communities were not serviced by either franchise. The size of the market that neither company serviced, including 70,000 people and representing 0.5% of the Ontario population, was not considered as significant but census data was adjusted to account for these areas. It was determined that Enbridge service area includes 61% of the Ontario population with the remaining 39% serviced by Union Gas.

In evaluating the various waste sources that can produce RNG, results for Union Gas and Enbridge service areas show that of the 4435 M m^3 RNG potentially produced in Ontario annually, the market potential for Union Gas is 71% of the total (3141 M m^3). The market potential for Enbridge is 29% (1294 M m^3). Despite the lower population serviced by Union Gas, their market potential for RNG is greater due to higher proportion of rural waste materials, including agricultural and forestry residues. In addition, the majority of Toronto municipal solid waste is now trucked from the Enbridge service area into a landfill located in the Union Gas service area.

These results were broken out by waste source and availability in the near-term or long-term horizons, as shown below:





The production and capture of RNG from Ontario wastes contributes to GHG reduction through two processes: emission reduction and fuel substitution. Emission reduction values represent the potential methane capture from anaerobic digestion within landfills and from a portion of animal manure, where fuel substitution relates more broadly to the potential of displacing fossil-fuel based NG with RNG produced from all wastes.

Total GHG reductions were estimated as 18980 kt CO_2 eq/yr for Ontario with emission reductions contributing more of the GHG reductions than fuel substitution as seen in the table below. About 54% of the Ontario GHG reductions arise from emission reductions, while the rest (46%) arises from fuel substitution. Of the total GHG reductions for Ontario, Union Gas service area accounts for 56% of this with 10700 kt CO_2 eq. The Enbridge service area accounts for 44% of the total Ontario GHG reductions with 8280 kt CO_2 eq.

GHG Reductions Due to Production of Renewable Natural Gas within the Franchise Areas

	Methane		GHG				
	Emission Reduction[1]	Fuel Substitution[2]	Emission Reduction[3]	Fuel Substitution[4]	Total[5]	Emission Reduction[6]	Fuel Substitution[6]
	(M m3/yr)		(kt CO_2 eq/yr)			(%)	
Near-Term	403	565	5755	1103	6857	84	16
Long-Term	-	729	-	1423	1423	0	100
Total Enbridge	403	1294	5755	2525	8280	70	30
Near-Term	320	807	4570	1575	6145	74	26
Long-Term	-	2332	-	4551	4551	0	100
Total Union Gas	320	3141	4570	6130	10700	43	57
Ontario	723	4435	10324	8655	18980	54	46

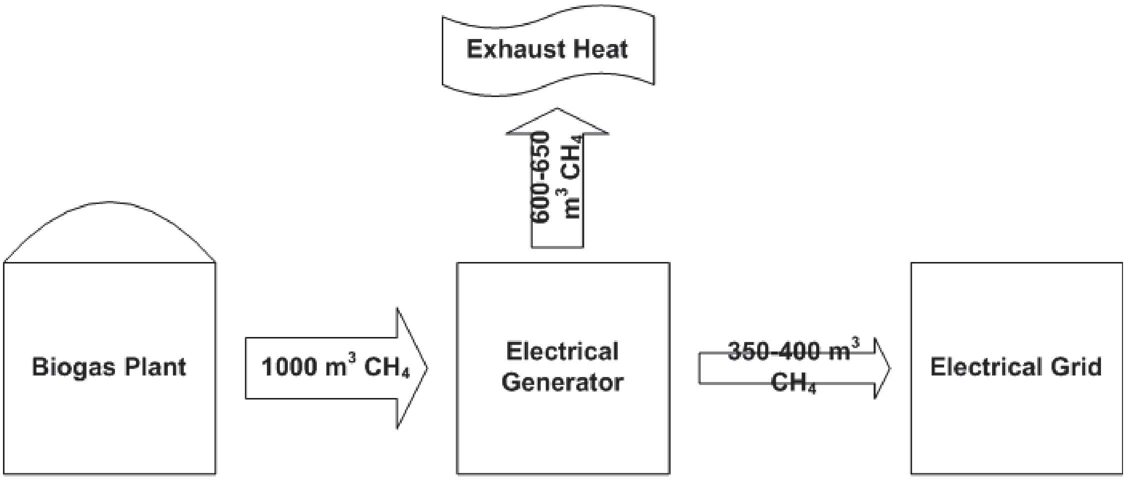
1 Calculated as the CH_4 generated in landfills plus 20% of the CH_4 generated from manure through AD
2 This is the total amount of potential CH_4 generated from all wastes
3 Calculated as column 2 (M m^3/yr) x 0.00068 (Mt CH_4/M m^3 CH_4) x 21 (Mt CO_2 eq/Mt CH_4) x 1000(kt CO2 eq/Mt CO2 Eq)
4 Calculated as column 3 (M m^3 CH_4/yr) x 0.00068 (Mt CH_4/M m^3 CH_4) x 2.87 (Mt CO_2 eq/Mt CH_4) x 1000(kt CO2 eq/Mt CO2 Eq)
5 Calculated as the sum of columns 4 and 5
6 Calculated as a percent of the total GHG (column 6)

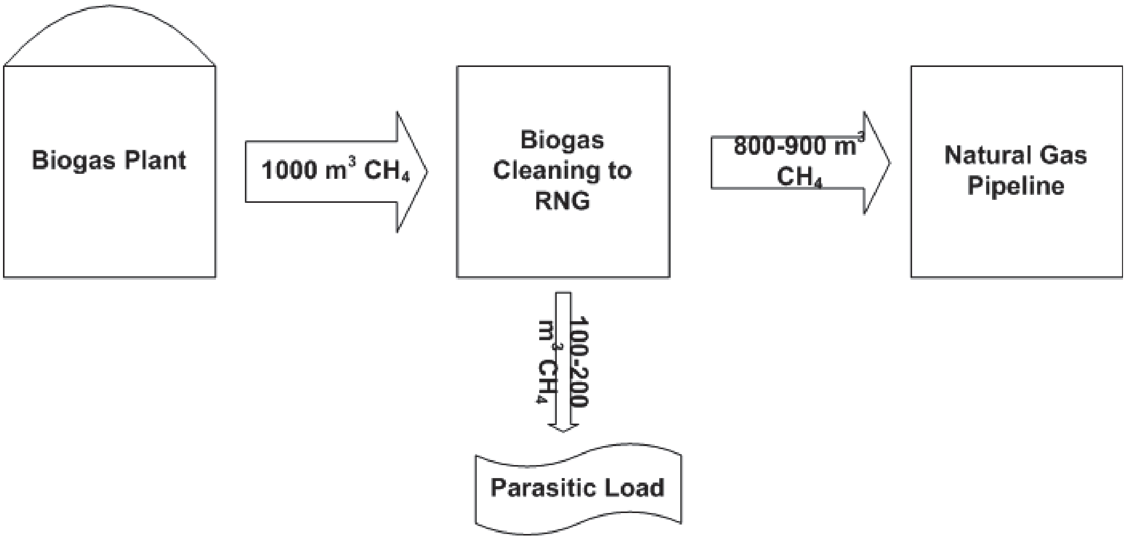
It has been shown that Enbridge has proportionately higher emissions reduction potential when compared to fuel substitution. This is a function of population size with associated municipal waste volumes, in addition to factoring in no forestry residues subject to gasification. In the near-term, Enbridge can realize GHG reductions of 6857 kt CO_2 eq/yr, representing 83% of its total potential GHG reductions. Over the long-term, an additional 1423 kt CO_2/yr (17%) of its total potential can be realized with further development of gasification processing.

Union Gas alternatively demonstrates higher fuel substitution potential when compared to emissions reduction. In the near-term, Union Gas can realize GHG reductions of 6145 kt CO_2 eq/yr, representing 57% of its total potential GHG reductions. Over the long-term, an additional 4551 kt CO_2/yr (43%) of its total potential can be realized with further development of gasification processing.

A comparison was made, as shown in the figure below, where biogas can be directed into electricity generation, or production of RNG for injection into a natural gas pipeline. As can be seen there is a wide difference in energy content retention with generating electricity (35-40% efficiency) compared to RNG production (80-90% efficiency).

It is evident that making RNG from existing biogas is a much preferable route energetically as it retains the most energy. If the raw biogas is used for RNG cleaning, in addition to improving the electric generator output by at least 100% (800 m^3 methane eq. vs 400 m^3 methane eq.) there is another beneficial consideration to be gained by producing RNG for the NG pipeline. This additional volume from energy efficiency represents fuel substitution of fossil fuel that would otherwise have to be provided in order to replace the inefficiency of electricity generation. As a result there are additional GHG emissions produced in electricity generation, which otherwise would be a GHG reduction in the NG pipeline as the RNG is a direct fuel substitution. It is evident that RNG from existing biogas is the preferable route energetically as well as providing the benefit of GHG reductions.


Exhaust Heat
600-650 m^3 CH_4
Biogas Plant
1000 m^3 CH_4
Electrical Generator
350-400 m^3 CH_4
Electrical Grid


Biogas Plant
1000 m^3 CH_4
Biogas Cleaning to RNG
800-900 m^3 CH_4
Natural Gas Pipeline
100-200 m^3 CH_4
Parasitic Load

Filed: 2011-09-30
EB-2011-0242
EB-2011-0283
Exhibit B
Tab 1
Appendix 1

GLOSSARY AND ABBREVIATIONS

AD	Anaerobic digestion
AITF	Alberta Innovates – Technology Futures
ARC	Alberta Research Council
BC	British Columbia
Biomethane	Biogas upgraded to natural gas quality
C	Carbon
CH_4	Methane
CO_2	Carbon Dioxide
C&D	Construction and Demolition
CGA	Canadian Gas Association
CH_4	Methane
CO_2	Carbon Dioxide
DM	Dry matter content
GHG	Greenhouse gases
GJ	Gigajoule, unit of energy
GWh	Gigawatthour, a unit of energy
ICI	Institutional, Commercial and Industrial
kt	kilo tonnes (1,000 tonnes) unit of mass
Mt	Mega tonnes (1,000,000 tonnes) unit of mass
kW	Kilowatt, unit of power
kWh	Kilwatthour, unit of energy
LFG	Landfill gas
M m3	Million cubic meters (1,000,000 m^3) a unit of volume
MSW	Municipal solid waste
MWh	Megawatthour, unit of energy
NG	Natural Gas
OMAFRA	Ontario Ministry of Agriculture and Rural Affairs
OME	Ontario Ministry of the Environment
PJ	Petajoule, a unit of energy
RNG	Renewable Natural Gas
Tonne	Metric ton (t)
WW	Waste water collected from municipal sewers
WWTP	Waste water treatment plant

CONSTANTS

Giga Joules (GJ)	1,000 Mega Joules (MJ)
Peta Joules (PJ)	1,000,000 Giga Joules (GJ)
Peta Joules (PJ)	277.77 Giga Watt hour (GWh)
RNG Density	0.00068 t/m^3
RNG Energy Content	37.69 GJ/(1,000 m^3)

1. INTRODUCTION

The use of biomass resources for energy production started early in human history, and continued to be the major source of energy until overtaken by coal then oil in the 19th and 20th centuries. Biomass supplies 5.9% of Canadian primary energy sources (through combustion and gasification and the production of biofuels), 15% of the world's energy and 35% of the developing countries' needs (Holmes and Edwards, 2003). The rest of the energy needs are supplied by fossil fuels. Concern about the use of fossil fuels and the resulting atmospheric buildup of carbon dioxide has led to a reevaluation of biomass resources for energy production.

The new efforts to use biomass for energy production centre on increasing efficiency, promoting sustainability of this resource and lowering carbon dioxide atmospheric levels by replacing fossil fuels.

There are energy production uses for biogas already established in Ontario. In 2009 the Province of Ontario passed into law the Green Energy Act, and adopted a green energy policy that includes a Feed-In Tariff (FIT) program delegating the responsibility for its implementation to the Ontario Power Authority (OPA). The program encourages investment in the generation, transmission and distribution, so that more renewable energy sources can be incorporated into Ontario's electricity system. The FIT program replaced the province's Renewable Energy Standard Offer Program (RESOP), which underwent review in 2008. As of the third quarter of 2009, the OPA had 1,422 MW of renewable energy supply capacity of which 87 MW are from bioenergy power generation projects under the RESOP Program. These projects provided the production of power from biomass sources but were not producing RNG for cleaning for NG pipeline.

In addition, there are several landfill operations in Ontario where methane gas is used as a fuel in generators to produce energy for their operation in the form of steam, electricity and heat. These operations include the EWSWA Regional Landfill (Essex Windsor); Glanbrook Landfill (Hamilton); Niagara Waste Systems Ltd. Landfill (Niagara Falls) and West Carlton Landfill (Ottawa).

This report evaluates the potential that Ontario wastes can produce energy from waste biomass by generating methane, which can then be used as a renewable natural gas (RNG) source. This path to energy production offers the advantages of new previously untapped sources of biomass and a solution to mounting waste problems.

1.1. OBJECTIVE

The objective of this project is to conduct a literature based study whose aim will be to assess the market potential for renewable natural gas generation from Ontario wastes, and its environmental benefits, including the relative greenhouse gas (GHG) impacts of capturing the generated methane. Specifically, it will:

- Provide data on market potential in Ontario for the generation of biogas (from agricultural, forestry, and municipal waste sources) based on a joint AITF-CGA study. It will also provide a breakdown of the LFG potential that is included in large landfills.
- Explain and quantify the reduction of greenhouse gas (GHG) release both in terms of methane destruction and in terms of natural gas displacement.
- Outline the efficiency differences of cleaning biogas into renewable natural gas vs. burning biogas in an engine for generating electrical power. It will include an explanation and diagrams that are understandable by a lay person on the range of difference in the "full cycle" efficiency between the two.
- Provide additional information germane to understanding the market potential and environmental benefits of biomethane in Ontario. It will evaluate market potential and environmental benefits for Ontario as a whole and separately for the Union Gas and Enbridge franchise areas.

1.2. APPROACH

We reviewed the literature with respect to the processes for converting waste into renewable natural gas (RNG), and evaluated these processes for availability in the near-term (up to 10 years) or long-term (over 10 years) time horizons (Figure 1). Then data was collected about the sources and quantities of wastes produced in Ontario and their geographical locations as they relate to the Enbridge and Union Gas franchise areas. We used the waste information to calculate potential quantities of RNG that can be produced from these wastes over the near-term and long-term horizons using assumptions about the conversion pathways and yields. These values were based on the scientific literature and our own experience and will be explained later in this report. The potential RNG production values are discussed for Ontario in terms of RNG production pathways, along with their technical feasibilities and the potential reduction in greenhouse gases realized from RNG production from waste.

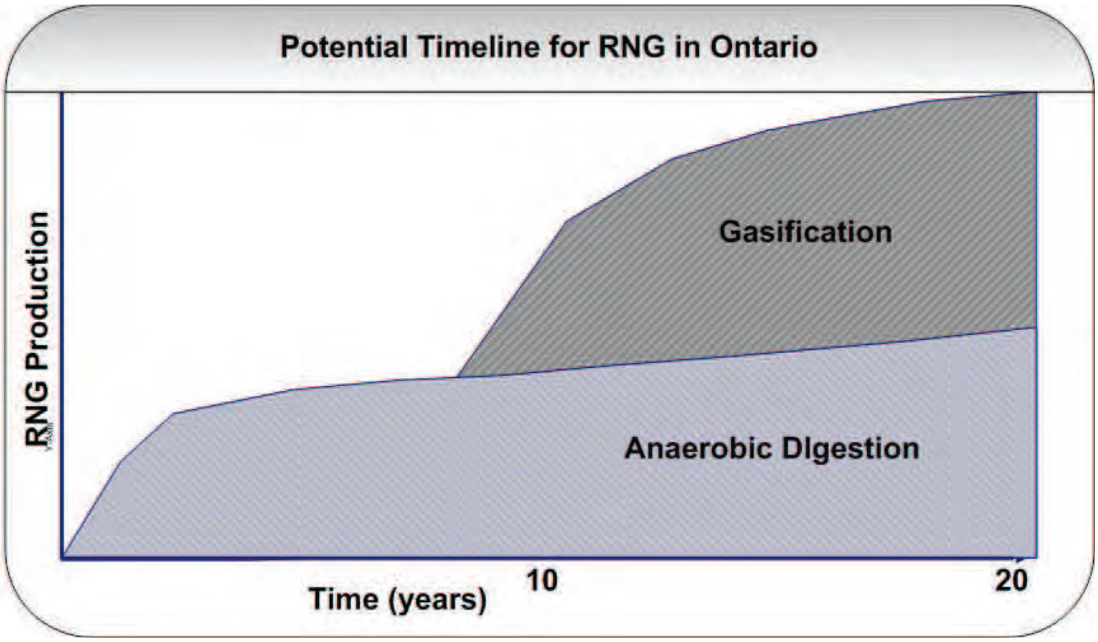


Figure 1. Potential Timeline for RNG Production in Ontario.

2. BIOGAS, SYNGAS AND RENEWABLE NATURAL GAS PRODUCTION PROCESSES FROM WASTES

Biomass can be converted to fuel for production of energy (electrical and thermal) or raw materials for the synthesis of chemicals, liquid or gaseous fuels such as hydrogen and methane. There are five different technological routes by which energy can be produced from biomass. These five processes are shown in Figure 2 and can be grouped into thermochemical (biomass combustion, gasification and pyrolysis) and non-thermal (anaerobic digestion and fermentation) processes. This report focuses on the two primary processes, anaerobic digestion and gasification, which are more directly related to the production of biogas and RNG.

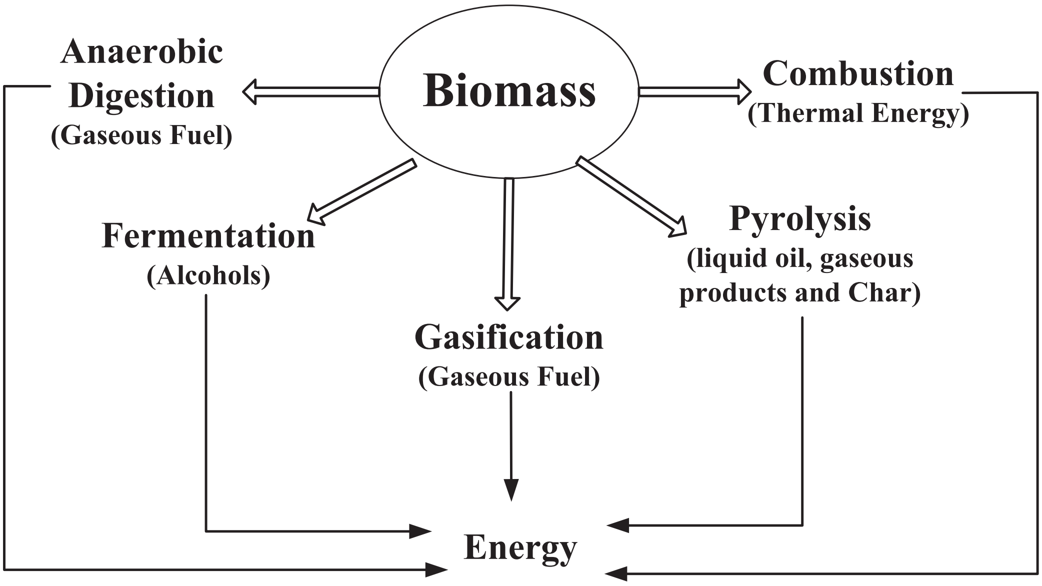


Figure 2. Potential Pathways for Energy Production from Biomass.

2.1. NEAR-TERM PROCESS AVAILABILITY

Anaerobic digestion (AD) through the use of digesters is now commonly employed for effluent and sewage treatment or for managing animal wastes. AD is a simple process that can greatly reduce the amount of organic matter which might otherwise end up in landfills or waste incinerators. In developing countries simple home and farm-based AD systems offer the potential for cheap, low cost energy from biogas. Environmental pressure on solid waste disposal methods in developed countries has increased the application of AD as a process for reducing waste volumes and generating useful byproducts. AD may either be used to process the source separated fraction of biodegradable waste, or alternatively combined with mechanical sorting systems, to process mixed municipal waste. Almost any biodegradable organic material can be processed with AD. This includes biodegradable waste materials such as waste paper, grass clippings, leftover food, sewage and animal waste. Anaerobic digesters can also be fed with specially grown energy crops or silage for dedicated biogas production. After sorting or screening the feedstock to remove physical contaminants, such as metals and plastics, the material is often shredded, minced, or hydrocrushed to increase the surface area available to microbes in the digesters and thereby increase the speed of digestion.

The material is then fed into an airtight digester where the anaerobic treatment takes place. There are four key biological and chemical stages of AD:

1. The first is the chemical reaction of hydrolysis, where complex organic molecules are broken down into simple sugars, amino acids, and fatty acids with the addition of hydroxyl groups.
2. The second stage is the biological process of acidogenesis where a further breakdown by acidogens into simpler molecules, volatile fatty acids (VFAs) occurs, producing ammonia, carbon dioxide and hydrogen sulfide as byproducts.
3. The third stage is the biological process of acetogenesis where the simple molecules from acidogenesis are further digested by acetogens to produce carbon dioxide, hydrogen and mainly acetic acid.
4. The fourth stage is the biological process of methanogenesis where methane, carbon dioxide and water are produced by methanogens.

A simplified generic chemical equation of the overall process is as follows:
$C_6H_{12}O_6 \rightarrow 3CO_2 + 3CH_4$

2.2. LONG-TERM PROCESS AVAILABILITY

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. Gasification is a very efficient method for extracting energy from many different types of organic materials. Its advantage is that using the syngas is more efficient than direct combustion of the original raw feedstock since more of the energy contained in the raw feedstock is extracted. 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. Gasification can also begin with materials that are not otherwise as useful fuels, such as biomass or organic waste. In addition, the high-temperature combustion refines out corrosive ash elements such as chloride and potassium, allowing clean gas production from otherwise problematic fuels.

Gasification of coal is currently widely used on industrial scales to generate electricity. However, almost any type of organic material can be used as the raw material for gasification, such as wood, biomass, or even plastic waste. Thus, gasification may be an important technology for renewable energy over the long-term, with further process development to handle these additional organic raw materials. Gasification relies on chemical processes at elevated temperatures, 700°C-1800°C, which distinguishes it from biological processes such as anaerobic digestion that produce biogas.

3. PRODUCTION OF BIOGAS, SYNGAS AND RENEWABLE NATURAL GAS FROM ONTARIO WASTES

The Ontario wastes that are amenable to producing RNG are those containing significant amounts of biomass and are primarily generated by the agricultural, forestry and municipal sectors.

3.1. AGRICULTURAL WASTES

Agricultural wastes containing significant biomass are mostly made up of crop residues and animal manures. These wastes can be converted to biogas and syngas through AD and gasification. The produced biogas can be cleaned up of potential contaminants and separated into CH_4 and CO_2 both of which can be sold as RNG and industrial grade CO_2. Syngas can be cleaned up, methanated and then separated into CH_4 and CO_2.

3.1.1. Crop Residues

The crop residues amenable for producing RNG are made up of the unused part of the crops. We obtained crop production (e.g. grain) data for the major crops grown in Ontario from the Ontario Ministry of Agriculture Food and Rural Affairs 2009 field crop data (OMAFRA, 2009) and are presented in Table 11 (Appendix 1). The values used as multiplier factors to estimate recoverable residues from crop production were obtained from a US Department of Energy study (Perlack et al, 2005). We assumed that the removable residue will represent 50% of the recoverable volumes of crop residues and is available for RNG production. We chose the 50% figure as we believe that some of the crop residues should be left on site to reduce erosion and return some of the nutrients back to the soil.

The data demonstrates that the largest available crop residues in Ontario are those from grain corn (42%) followed by soybeans (29%) and wheat (21%). These 3 crop residues make up 92% of the available Ontario total. Any effort to harness this resource for RNG production will have to take into account the geographic distribution of these crops.

3.1.1.1 Near-Term RNG Potential from Crop Residues

Conversion of available crop residues to methane is shown in Table 1. The data shows the potential production of methane from biogas over the near-term through AD processing. Biogas generation from the crop residues assumes that only 20% of the material is amenable to digestion and that 300 m^3 CH_4/dry t of residues is produced (Wiese and Kujawski, 2007). The total Ontario potential RNG production from crop residues in the near-term is estimated to be 378 M m^3/yr from AD, or 18% of the total RNG potentially produced from this source.

3.1.1.2 Long-Term RNG Potential from Crop Residues

The data from Table 1 shows the longer-term potential production of methane from syngas through gasification of the residues not consumed in the AD process. Gasification of the crop residues assumes a process conversion efficiency of 65% according to the following reaction where 2 moles of carbon are required to produce 1 mole of CH_4 and 1 mole of CO_2:

$$2C + 2H_2O = CH_4 + CO_2$$

The combined gasification and methanation processes required to convert biomass to methane are reported to have efficiencies that vary from 64 to 79% (Mozaffarian et al, 2005 and Zwart and Rabou, 2006). We chose to use an efficiency of 65% as a conservative value.

Table 1. Potential RNG Production from Ontario Crop Residues

	Removable Residue[1]	Methane Production		
		Near-Term (AD[2])	Long-Term (Gasification[3])	Total[4]
	(kt dry/yr)	(M m^3/yr)		
Enbridge	1151	69.1	322	391
Union Gas	5148	309	1440	1749
Ontario	6299	378	1762	2140

1 Table 1
2 Calculated as crop residue (dry kt/yr)x10^{-3} (Mt/kt)x0.2x 300 (Mm3 CH_4/Mt dry). (Wiese and Kujawski, 2007). Assume that only 0.2 (20%) of the crop residue is amenable to AD.
3 Calculated from the AD residue as (dry Kt residue/yr)x10^{-3} (Mt/kt) x 0.5 (Mt C/Mt residue) x (16 Mt CH_4/ 24 Mt C) x 0.65. Assumes a gasification conversion efficiency of waste carbon to CH_4 and CO_2 carbon of 65%. Residues are assumed to be those not converted in the AD process.
4 Calculated as the sum of AD and gasification methane

The data shows that the greatest potential for producing RNG from crop residues can be realized over the long-term, through a gasification process (Table 1) as it consumes most of the biomass while AD is limited to about 20% of that biomass. The total Ontario potential RNG production from crop residues over the long-term is estimated to be 1762 M m^3/yr from gasification, or 82% of the total RNG potentially produced from this source.

3.1.2. Livestock Manure

Manure production on Canadian farms varies according to the type of animals and the animal population numbers but all are amenable for producing RNG. We estimated manure production for the major animal populations according to Ontario Ministry of Agriculture Food and Rural Affairs (OMAFRA, 2009b,c,d,e) data for cattle, hogs, sheep and poultry in Tables 12 to 14 (Appendix 1). Manure production was calculated using animal population numbers and a specific average daily manure production rate for each animal as suggested by Klass (1998). The average manure production rates (kg dry/head/day) varied with the animal type from a high of 4.64 kg/animal for cattle to 0.0101 for turkeys (Tables 12-14 of Appendix 1). The manures available for RNG production are less than what is produced as some of the manures are already used for other purposes. We estimated that the availability of cattle manure was 25% of the total cattle manure produced with different availability indices for hogs (85%), sheep (10%) and poultry (85%). These indices were used according to the data published for a BC bioenergy inventory report (Ralevic and Layzell, 2006).

The total Ontario manure production from each animal type available for AD and gasification are shown in Table 2. The Ontario data shows that the largest available manure residues representing 99% of the total are those from cattle (45%) followed by hogs (33%) and chickens (21%), with about 1% from turkey and sheep manures (Figure 3).

3.1.2.1 Near-Term RNG Potential from Manures

Conversion of available manure residues to methane is shown in Table 2. The data shows the potential production of methane from biogas over the near-term through AD processing. Biogas generation from the manures assumes that 116 Mm^3 CH_4/dry Mt of manure is produced. This number was calculated as an average from the specific biogas generation potentials for each manure (Electrigaz, 2007) multiplied by its manure production ratio (specific manure production/total manure production).

The total Ontario potential RNG production from manure residues is estimated to be 197 M m^3/yr in the near-term, or 39% of the RNG potentially produced from this source.

3.1.2.2 Long-Term RNG Potential from Manures

The data from Table 2 shows the longer-term potential production of methane from syngas through gasification of the manures not consumed in the AD process. Gasification of the manure residues assumes a process similar to that for crop residues at a conversion efficiency of 65% and a manure carbon content of 40% (Klass, 1998).

The data shows that the greatest potential for producing RNG from livestock manure can be realized over the long-term, through a gasification process (Table 2). The total Ontario potential RNG production from livestock manure over the long-term is estimated to be 306 M m^3/yr from gasification, or 61% of the total RNG potentially produced from this source.

Table 2. Potential RNG Production from Ontario Manures.

	Total Manure[8] (dry Mt/yr)	Near-Term (AD[9])	Long-Term (Gasification[10])	Total Manure[11]
		Methane (M m3/yr)		
Enbridge	0.356	41.2	64	105
Union Gas	1.351	156	241	397
Ontario	1.707	197	306	503

8 Calculated as the sum of all manures (cattle, hogs, sheep, chicken and turkey)
9 Calculated as total manure (dry Mt/yr) x 116 (Mm^3 CH_4/Mt dry manure) (Electrigaz, 2007)
10 Calculated from the AD residue as (dry Mt manure/yr) x 0.4 (Mt C/Mt manure) x (16 Mt CH_4/ 24 Mt C) x 0.65 x(1/ 0.00068 Mt CH_4/M m^3 CH_4) . Assumes a gasification conversion efficiency of waste carbon to CH_4 and CO_2 carbon of 65%
11 Calculated as the sum of AD and gasification methane

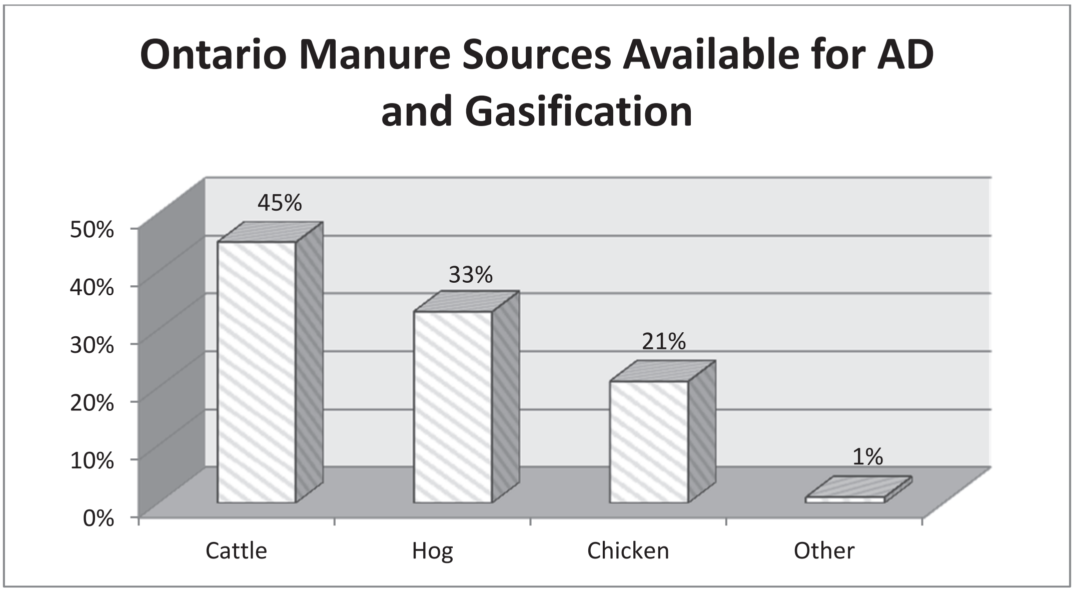


Figure 3. Ontario Manure Sources Available for AD and Gasification

3.1.3 Total Agricultural Waste

The potential RNG production arising from agricultural wastes consists of both the AD and gasification processes of manure and crop waste. In total, this represents 2643 M m^3/yr of RNG. Of this amount, the potential is 575 M m^3/yr (22%) over the near-term in Ontario; and an additional 2068 M m^3/yr (78%) over the long-term with new process developments for gasification.

3.2 FORESTRY WASTES

Forestry residues are made up of forest operation residues which are generated during harvest operations and subsequent wood treatment in either sawmills or pulp and paper plants. Production of forestry wastes was calculated from the data reported in the Ontario Ministry of Natural Resources Forest Biomass (2003) data (Norrie, 2011). Estimates were then made of total forest residues (kt Carbon/year) as by Wood and Layzell (2003). Gasification of the harvested forest residues to RNG is assumed to occur with a process efficiency of 65% as discussed in previous sections.

3.2.1 Long-Term RNG Potential from Forestry Wastes

Forest residue data are presented in Table 3. The total Ontario potential RNG production from forest residues is estimated as 188 M m3/yr. This RNG would be produced through a gasification process, and therefore represents long-term RNG potential. The AD process is not applicable to forestry wastes, and as a result there is no near-term RNG production potential with these waste materials.

Table 3. Potential RNG Production from Ontario Forestry Wastes

	Forestry Biomass[1] m^3 (000's)	Forestry Residues[2] (kt C / yr)	Total Methane Generation[3] (M m^3/yr)
Enbridge	31.5	7.50	4.85
Union Gas	1211	288	184
Ontario Total	1242	296	188

1 Ontario Ministry of Natural Resources, Forest Biomass (2003) data (Norrie, 2011).
2 Assumes 4.2m^3 biomass/tonne carbon (Wood and Layzell, 2003)
3 Calculated as Column 3 (kt C/yr) x (16 kt CH_4/ 24 kt C) x (1 Mt CH_4/1000 kt CH_4) x 0.65 x (1/0.00068 M t CH_4/M m^3 CH_4). Assumes a gasification conversion efficiency of waste carbon to CH_4 and CO_2 carbon of 65%

The total RNG production from forestry residues in Ontario as calculated is viewed as a conservative estimate compared to the national report provided to the CGA. That report included data of the potential non-stem residue left onsite at forestry operations, whereas the dataset in this report focused on processed wastes from forestry operations including hog fuel, sawdust, shavings, bark etc. Although some of non-stem residue left onsite represents additional long-term RNG potential, in practical terms there will be a significant percentage which falls outside of the Union Gas service area in Northern Ontario, and it would be cost prohibitive to truck these residues from remote forestry regions into their service area.

3.3 MUNICIPAL WASTES

Ontario municipal wastes considered as potential sources for RNG production comprises of four types of waste materials: (1) solid wastes collected from homes and businesses by municipalities (MSW, including SSO); (2) landfill gas recovered from closed landfills (LFG); (3) wastewaters (WW) collected through municipal sewer systems, and (4) municipal biosolids which are the solid materials collected from the settling of the wastewaters.

3.3.1. Municipal Solid Waste

MSW residues are made up of wastes collected from residential areas (households), industrial and commercial and institutional (ICI) wastes, and construction and demolition (CD) wastes. Some of these wastes are collected by municipalities while others are collected by private companies.

The amounts of various Ontario-disposed MSW fractions are presented in Figure 4 for 2008 (Statistics Canada, 2010) and Table 15 (Appendix 1). The data shows that ICI wastes makes up the highest fraction of the total MSW at 47%, followed by household sources (34%) and CD wastes (19%). Statistics Canada reported only the total amounts of residential MSW and a combined number for the ICI and C&D wastes. We separated the ICI and C&D numbers by using the same ratio of these two wastes as reported by the city of Ottawa based on their waste production (City of Ottawa, 2007).

The amounts of MSW that are amenable to AD and gasification are reported in Table 15 (Appendix 1). We estimated that only 25% of the household wastes are amenable to AD (Ostrem, 2004) while none of the other wastes were considered to contain significant amounts of digestible wastes. This assumption underestimates the amount of digestible waste by not including the amount of food wastes disposed of from restaurants and institutional cafeteria. The gasifiable waste quantities were assumed to consist of the undigestible biomass from household wastes, 50% of the ICI wastes and 30% of the CD wastes (mostly wood products).

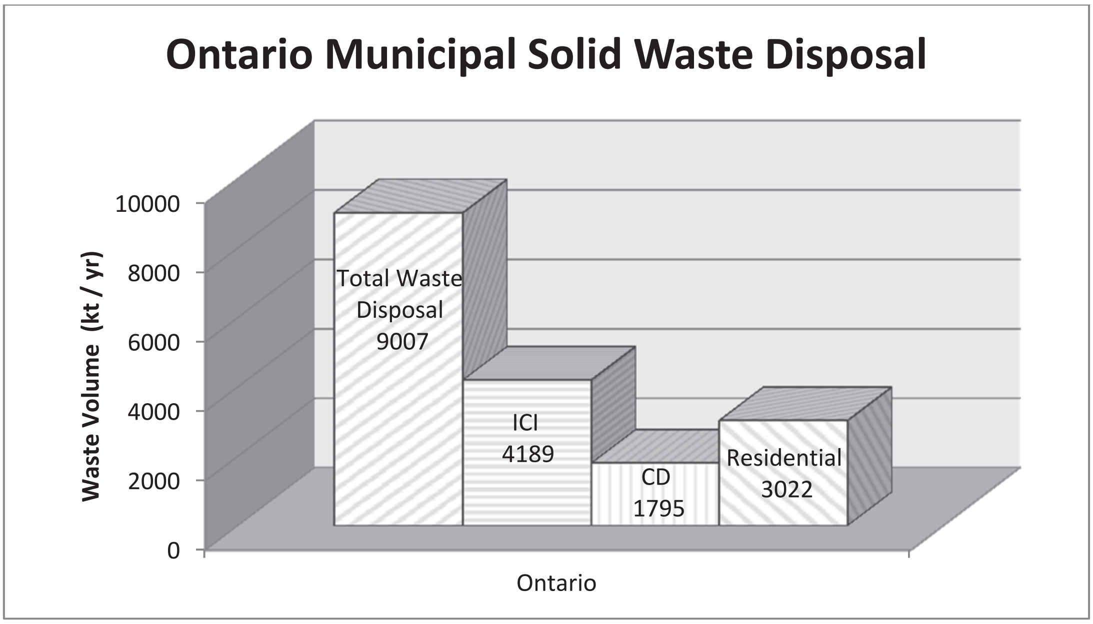


Figure 4. Ontario Municipal Solid Waste Disposal

3.3.1.1 Near-Term RNG Potential from Municipal Solid Waste

Generation of RNG from these wastes is presented in Table 4 showing that in Ontario AD can produce approximately 45 M m^3/yr. This represents 6% of the total potential RNG which could be produced from this waste source.

3.3.1.2 Long-Term RNG Potential from Municipal Solid Waste

Data presented in Table 4 shows that over the long-term in Ontario, gasification can potentially produce an additional 738 M m^3/yr of RNG. This represents 94% of the total potential RNG which can be produced from this waste source.

Table 4. Potential RNG Production from Ontario Municipal Solid Wastes (2005)

	Methane Production		
	Near-Term (AD[1])	Long-Term (Gasification[2])	Total[3]
	(M m^3/yr)		
Enbridge	18.2	297	315
Union Gas	27.2	441	469
Ontario	45.4	738	784

1 Calculated as Column 6 (Table 8) (dry kt /yr) x 172 (k m^3 CH_4)/(kt dry) x (1 M m^3/1000 k m^3) .
2 Calculated as Column 7 (Table 8) (dry kt C/yr) x (16 kt CH_4/24 kt C) x 0.65 x(1/0.00068 kt CH_4/k m^3 CH_4) x (1 M m^3/1000 k m^3). Assumes a gasification conversion efficiency of waste carbon to CH_4 and CO_2 carbon of 65%
3 Calculated as the sum of Methane generated by Anaerobic Digestion (column 2) and Gasification (column 3)

3.3.2. Wastewater

Wastewaters are the mixed liquid and solid wastes collected through sewers and delivered to a wastewater treatment plants. These wastes can produce RNG through AD in large digesters where some of the biomass solids are converted into CH_4 and CO_2. This practice is common for larger municipalities where the original aim was to reduce the solids contents of the wastes before discharge from the plants.

We estimated the generation for wastewaters for Ontario from Environment Canada data (Environment Canada, 2001) for the Canadian generation in 1999 and the population sizes in 2006 (Statistics Canada, 2007). Total population numbers were adjusted to reflect the county data for service provided by Enbridge and Union Gas. Environment Canada also reported that 97% of the Canadian population is served with some form of wastewater treatment.

3.3.2.1 Near-Term RNG Potential from Wastewater

The potential RNG produced from the AD of these wastes is presented in Table 5. We estimated the production of RNG using data reported for many Ontario wastewater anaerobic digesters by Wheeldon et al. (2005), where the specific methane production was reported as 0.0336 m^3 CH_4/m^3 wastewater. The total Ontario potential RNG production from wastewaters is estimated to be about 68 M m^3/yr in the near-term. Since the gasification process is not applicable to wastewater, the full potential of RNG production can be realized in the near-term through AD.

Table 5. Potential RNG Production from Ontario Wastewaters (2006)

	Population[1]	Wastewater Production		Near-Term Methane Production
	(000's)	(m3/d)[2]	(M m3/yr)[3]	(M m3/yr)[4]
Enbridge	7358	3376	1.23	41.5
Union Gas	4731	2171	0.79	26.6
Ontario	12089	5547	2.02	68.1

1 Statistics Canada. 2007
2 Calculated as Column 2 (p) x 0.97 x 0.474 (m^3/d/p). (In 1999, 97% of Canadians used Wastewater treatment facilities that produced 14,400,000 m^3/day (population of 30,404,000) or 0.474 m^3/person/day). (**Environment Canada. 2001.)**
3 Calculated as (Column 3 (m^3/d) x 365 d/yr)/(1000000 m^3/M m^3)
4 Calculated as Methane production (at 60% of biogas) = Column 4 (M m^3/yr) x 0.0336 (M m^3 CH_4/M m^3 wastewater) (**Wheeldon et al, 2005**)

3.3.3 Biosolids

Biosolids are the solids collected through solid liquid separation of the wastewaters before liquid discharge from the wastewater treatment plant. Some of these wastewaters would have previously undergone AD. Currently, biosolids are disposed on land, landfills or composted.

Quantities of biosolids also correlate well with population size. We estimated the amount of biosolids produced in Ontario from the population size and the specific biosolids production rate of 0.063 kg (dry Biosolids)/person/day (Klass, 1998). Similar to wastewater production, the total population numbers were adjusted to reflect the county data for service provided by Enbridge and Union Gas.

3.3.3.1 Long-Term RNG Potential from Biosolids

Production of RNG from biosolids is through gasification of the dried biosolids, and as a result this waste source represents a long-term RNG potential. We assumed that the carbon content to be 40% according to Klass (1998) and that the gasification efficiency is 65% as discussed earlier in this report. Table 6 shows the data for biosolids production and potential RNG generation from these wastes. The total long-term potential RNG production from biosolids in Ontario is estimated at 69 M m^3/yr. Since this waste source is not amenable to AD, there is no near-term RNG potential with it.

Table 6. Potential RNG Production from Ontario Biosolids (2006)

	Population[1]	**Biosolids Production**		**Long-Term Methane Production[4]**
	(000's)	**(kt dry/yr)[2]**	**(dry kt C/yr)[3]**	**(M m3/yr)**
Enbridge	7358	0.164	0.066	41.8
Union Gas	4731	0.105	0.042	26.9
Ontario	12089	0.269	0.108	68.7

1 Statistics Canada. (2007).
2 Calculated as Column 2 (p) x 0.97 x 0.063 (kg dry 16iosolids/d/p) x 365 (d/yr) x 10^{-3} (t/kg). (**Klass, 1998**)
3 Calculated as Column 3 x 0.4 (kt C/kt 16iosolids). Assumed a 40% carbon content for the Biosolids. (**Environment Canada. 2001.) and (Klass, 1998**)
4 Calculated as Column 4 (dry kt C/yr) x (10^{-3} Mt C/kt C) (16 Mt CH_4/ 24 Mt C) x (1/0.00068 Mt CH_4/ M m^3 CH_4) x 0.65. Assumes a gasification conversion efficiency of waste carbon to CH_4 and CO_2 carbon of 65%

3.3.4 <u>Landfills</u>

Landfills have been the traditional repositories for Canadian solid wastes. The large biomass quantities collected in these landfills after closure tends to anaerobically digest naturally to produce CH_4 and CO_2. Most of the produced gases escape to the atmosphere, but in some landfills they are collected and harnessed to produce power.

3.3.4.1 <u>Near-Term RNG Potential from Landfill Gas</u>

Table 7 shows the data for the estimated methane generation from Ontario landfills through AD, and represents the near-term potential for RNG production. The data also shows the amounts of methane captured and by difference from the generated values, the amount emitted to the atmosphere. Emitted methane gas is considered a greenhouse gas with potential activity equivalent to 21 times that of CO_2. Table 7 shows the amounts of greenhouse gas emitted (as CO_2 eq.) due to the release of methane from landfills. The total potential RNG generation from Ontario landfills is estimated at 684 M

m^3/yr with only 27% captured as of 2005 survey (Environment Canada). The potential exists to increase the capture of the generated methane due to the availability of established technology for landfill gas capture, cleaning and separation into CH_4 and CO_2.

Table 7. Potential RNG Generation and Capture from Ontario Landfills (2005)						
	Near-Term Methane Generation[1]	**GHG Generation[2]**	**LFG projects[3]**	**Methane Captured[3]**	**Methane Emitted[4]**	**GHG Emitted[2]**
	(M m3/yr)	**(kt CO_2 eq/yr)**	**Number**	**(M m3/yr)**	**(M m3/yr)**	**(kt CO_2 eq/yr)**
Enbridge	395	5636	-	-	-	-
Union Gas	289	4129	-	-	-	-
Ontario	684	9,765	19	185	499	7,121

1 Thompson et al (2006)
2 Calculated as methane generation x 21
3 Environment Canada (2007b)
4 Calculated as the difference between the methane generated and captured

Ontario Ministry of the Environment Regulation 217/08 (amending O.Reg. 347/90) requires mandatory landfill gas collection and use or flaring (thermal destruction) for all operating or proposed new or expanding landfills with total waste disposal capacities larger than 1.5 million cubic metres. According to the Ontario MOE website, there are over 2300 MSW landfills in the province. Of these, 2283 are classed as small landfills (958 currently open; 1325 closed) and the remaining 32 are classed as large landfills with disposal capacities greater than 1.5 million cubic meters.

Of the 32 large landfills, 30 have reported Total Weight Received data for their facilities for 2009, as posted on the Ontario MOE website (Table 8), and this data was used to calculate the potential methane generation. Table 8 shows that these 30 large landfills are estimated to produce approximately 76 M m^3/yr of methane, which represents 11% of the total methane generation from all Ontario landfills (Table 8).

Methane generation data was reported in Table 7 for both Enbridge and Union Gas separately. These calculations were based on summed estimates from large landfills (Enbridge 31% of LFG volume; Union Gas 69% of LFG volume) and small landfills (using population ratios: Enbridge 61% of the remaining LFG volume; Union Gas 39% of remaining LFG volume). It should be noted that the large landfills are required to have LFG capture systems in place, however according to communication with the MOE, at least 10 are still in process of compliance. As a result, Table 7 has omitted specific data for Enbridge and Union Gas franchise areas for methane capture and emissions. These calculations are presented however in the Ontario total in Table 7.

Table 8. Potential RNG (2009) from Large Ontario MSW Landfills[1]

Landfill Site Name	Landfill Volume		Methane Generation[2]	Franchise Area
	Total Approved Capacity	Total Weight Received		
	(M m^3)	(kt/yr)	(M m^3/yr)	
Bensforth Rd. – Peterborough	4.5	69.3	1.04	Enbridge
City of Thunder Bay Solid Waste and Recycling Facility	8.7	141	2.11	Union Gas
Cornwall Landfill – Cornwall	3.3	62.4	0.94	Union Gas
Deloro Landfill	5.8	60.0	0.90	Union Gas
EWSWA Regional Landfill – Essex Windsor	12.8	159	2.40	Union Gas
Glanbrook – Hamilton	13.2	144	2.16	Union Gas
Green Lane – St. Thomas	16.7	320	4.81	Union Gas
Halton Regional Landfill – Milton	No information supplied		-	Union Gas
Humberstone – Niagara Region	No information supplied		-	Enbridge
Lafleche Stormont	7.4	269	4.04	Enbridge
Lindsay Ops – Kawartha Lakes	2.3	31.3	0.47	Enbridge
Line 5 Landfill – Sault Ste. Marie	2.3	59.4	0.90	Union Gas
Merrick Landfill – North Bay	2.8	49.3	0.74	Union Gas
Mohawk St. – Brantford	13.4	84.8	1.28	Union Gas
Newalta Stoney Creek Landfill	6.3	477	7.18	Union Gas
Niagara Regional Road 12	1.7	18.7	0.28	Enbridge
Petrolia – Lambton	4.7	364	5.49	Union Gas
Richmond – Napanee	2.8	10.0	0.15	Union Gas
Ridge Landfill – Blenheim	36.8	676	10.18	Union Gas
Salford – Oxford County	5.9	70.9	1.07	Union Gas
Sandy Hollow – Barrie	3.9	44.7	0.68	Enbridge
Springhill – Ottawa	1.2	101.9	1.53	Enbridge
Stratford – Stratford	5.3	25.7	0.38	Union Gas
Sudbury Regional Landfill	7.6	69.2	1.04	Union Gas
Tom Howe – Haldimand	1.9	49.9	0.75	Union Gas
Trail Road – Ottawa	17.0	258	3.93	Enbridge

W12A – London	13.8	274	4.12	Union Gas
Walker Bros – Niagara Falls	31.0	618.0	9.29	Enbridge
Warwick – Lambton	26.5	154	2.32	Union Gas
Waterloo Landfill	14.7	215	3.23	Union Gas
West Carlton – Ottawa Carp Rd.	8.7	72.5	1.09	Enbridge
WSI – Ottawa – Navan Rd.	7.6	121.1	1.82	Enbridge
Total	291	5072	76.3 [Enbridge: 24.1 Union Gas: 52.2	

[1]Ontario Ministry of the Environment website
http://www.ene.gov.on.ca/environment/en/monitoring_and_reporting/limo/index.htm
Landfill Inventory Management Ontario
[2] MSW organic fraction is assumed to generate methane through AD and is calculated similar to the MSW section discussed previously.

3.3.5 Total Municipal Wastes

A summary of the contributions of each municipal waste to the total municipal potential RNG production is presented in Table 9. The data shows that the largest sources of potential RNG are from solid wastes (MSW) and Landfills. In Ontario, MSW contributes 784 M m^3/yr of RNG while Landfills contribute 684 M m^3/yr with approximately 68 M m^3/yr each from wastewaters and Biosolids. This is understandable considering the much larger solid production of wastes from the primary two sources. Total potential RNG production in Ontario from municipal waste is 1604 M m^3/yr.

3.3.5.1 Near-Term RNG Potential from Municipal Wastes

Approximately 50% of the total potential RNG produced from the four municipal waste sources can be realized in the near-term with AD processes. Of the 797 M m^3/yr which could potentially be produced in the near-term, over 85% of it would be accessed from landfill gas. The remaining 15% would be split between wastewater and municipal solid waste.

3.3.5.2 Long-Term RNG Potential from Municipal Wastes

The remaining 50% of the total potential RNG produced from the four municipal waste sources could be realized over the long-term with gasification process. Of the additional 807 M m^3/yr which could potentially be produced in the long-term, over 90%

of it would be accessed from gasification of municipal solid waste. The remaining 10% would be available from Biosolids processing.

Table 9. Annual Potential RNG Production from Ontario Municipal Wastes

	LFG	MSW			Wastewater	Biosolids	Total Methane Production
	Near-Term (AD)	Near-Term (AD)	Long-Term (Gasification)	Total	Near-Term (AD)	Long-Term (Gasification)	
	(M m^3/yr)						
Enbridge	395	18.2	297	315	41.5	41.8	793
Union Gas	289	27.2	441	469	26.6	26.9	812
ON	684	45.4	738	784	68.1	68.7	1604

4. SUMMARY OF TECHNICAL FEASIBILITY AND METHANE PRODUCTION FROM ONTARIO WASTES

Production of RNG from Ontario wastes was shown to arise from the application of two well used and understood processes: Anaerobic digestion (AD) and gasification.

AD is a naturally occurring process that has been used industrially to produce biogas from agricultural, municipal and industrial processes such as food processing. Production of RNG adds the processes of biogas cleaning and gas separation to the AD process, and with current technologies this is available in the near-term.

Gasification is an old industrial process that has been used mainly to process coals into gaseous products and to further use these gases to produce energy. Gasification of coal into RNG has been demonstrated in the US and Europe. The application of the technology has until recently been limited by the low NG prices. Gasification of wastes is an established process where the produced syngas is used to produce energy. Examples of using this technology for various wastes are found mostly in Europe and to a lesser degree in North America. Syngas is made up of hydrogen, carbon monoxide and smaller amounts of methane.

Production of RNG through gasification does require the cleaning of the syngas, methanation and further separation into methane and carbon dioxide. Methanation has been industrially applied in Europe for coal but much less for waste gasification. The processes of gas cleaning and separation are common to both AD and gasification. Gas cleaning is dependent on the nature of the contaminants to be removed and thus, the source of the biogas/syngas. Most contaminants can be removed by existing processes that have been applied industrially; the challenge is to integrate these technologies into the RNG production chain. Similarly, gas separation has been practiced for many industrial processes and the challenge is to adapt the existing technologies into the RNG production process. Due to the process development time frame, this would be considered a long-term potential.

Based on our findings, it is envisioned that the AD process will be the main source of RNG in the next 5 to 10 years with gasification contributing afterwards. This is based on the availability of the technologies, prior use and acceptance by industry, and the need for further technology development activities.

A summary of all potential RNG that can be produced from Ontario wastes is presented in Table 10 and Figure 5. The data shows that a potential total of 4435 M m^3/yr of RNG can be produced from Ontario wastes. Agricultural wastes have the potential to produce 2643 M m^3/yr (60% of total), followed by 1604 M m^3/yr from municipal wastes (36% of total) and 188 M m^3/yr from forestry wastes (4% of total).

Table 10. Annual Potential RNG Production from Ontario Wastes

	Agriculture Wastes				Forestry Residues	Municipal Wastes					Total Methane Production
	Manure		Crops			MSW		Landfill	WW	Biosolids	
	Near-Term (AD)	Long-Term (Gas)	Near-Term (AD)	Long-Term (Gas)	Long-Term (Gas)	Near-Term (AD)	Long-Term (Gas)	Near-Term (AD)	Near-Term (AD)	Long-Term (Gas)	
	(M m^3/yr)										
Enbridge	41.2	64	69.1	322	4.85	18.2	297	395	41.5	41.8	1294
Union Gas	156	241	309	1440	184	27.2	441	289	26.6	26.9	3141
Ontario	197	306	378	1762	188	45.4	738	684	68.1	68.7	4435

Note: AD = anaerobic digestion process; Gas = gasification process

4.1 NEAR-TERM RNG POTENTIAL FROM ONTARIO WASTES

In the near-term AD has the potential to produce 1372 M m^3/yr (31% of total) from all of the various Ontario waste sources reviewed. Of this amount, almost 60% of it will come from municipal wastes, with the remaining 40% from agricultural sources.

4.2 LONG-TERM RNG POTENTIAL FROM ONTARIO WASTES

Over the long-term the use of gasification has the potential to produce most of the RNG in Ontario, as shown in Figure 6, with an additional 3063 M m^3/yr (69% of total) produced by this process. Of this amount 68% of the potential RNG can be produced from Agricultural wastes, with 26% coming from Municipal waste sources and the remaining 6% coming from forestry residues.

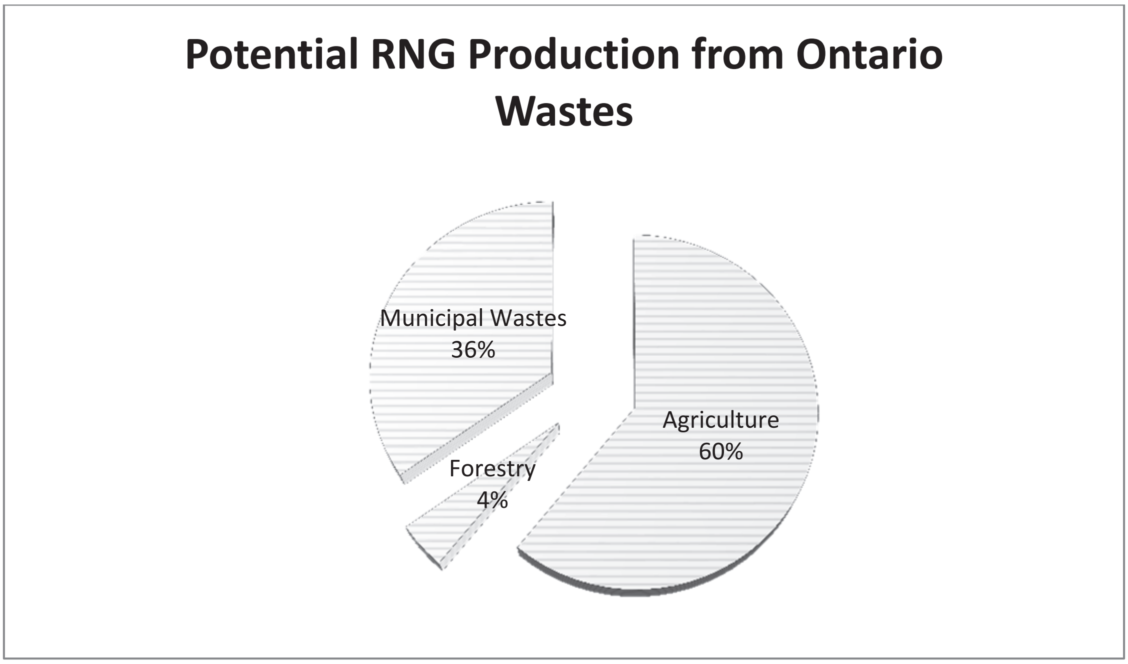


Figure 5. Potential RNG Production from Ontario Wastes.

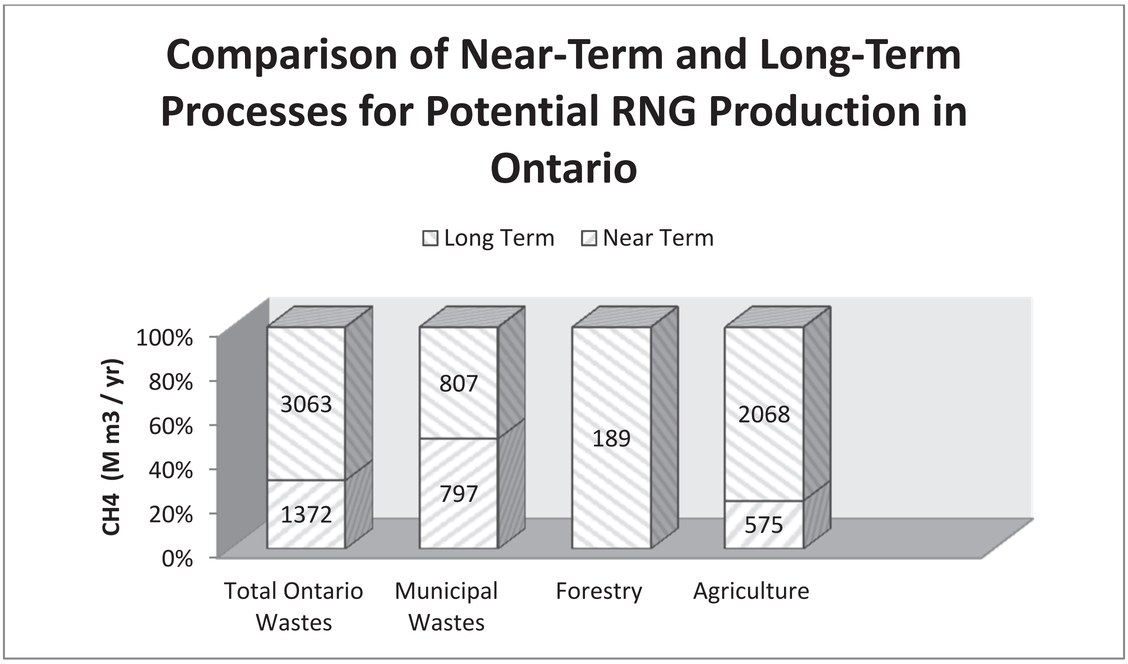


Figure 6. Comparison of Near-Term and Long-Term Processes for Potential RNG Production in Ontario.

We compared the relative size of our potential RNG estimates to the current NG use for the residential and commercial sectors and the results are presented in Figure 7 and Table 16 (Appendix 1). The potential Ontario generation of 1372 M m^3/yr of RNG in the near-term corresponds to an energy value of 52 PJ/yr or 14,444 GWh of electricity (Table 16). RNG production can account for a portion of the approximately 24,000 M m^3/yr of NG consumption in the near-term, (2010 distribution volume provided by Enbridge: 10,940 M m^3; Union Gas 13,300 M m^3) with up to 6% of the residential, commercial and industrial use potentially produced from Ontario wastes if all of the methane was able to be captured. Over the long-term with gasification process capabilities becoming available, there would be an additional 3063 M m^3/yr of RNG (115 PJ/yr of energy, or 31,944 GWh of electricity). Potentially over the long-term and if all methane were captured, this would correspond up to an additional 12% of the current NG consumption in Ontario, bringing the total over the long-term up to 18% of NG consumption.

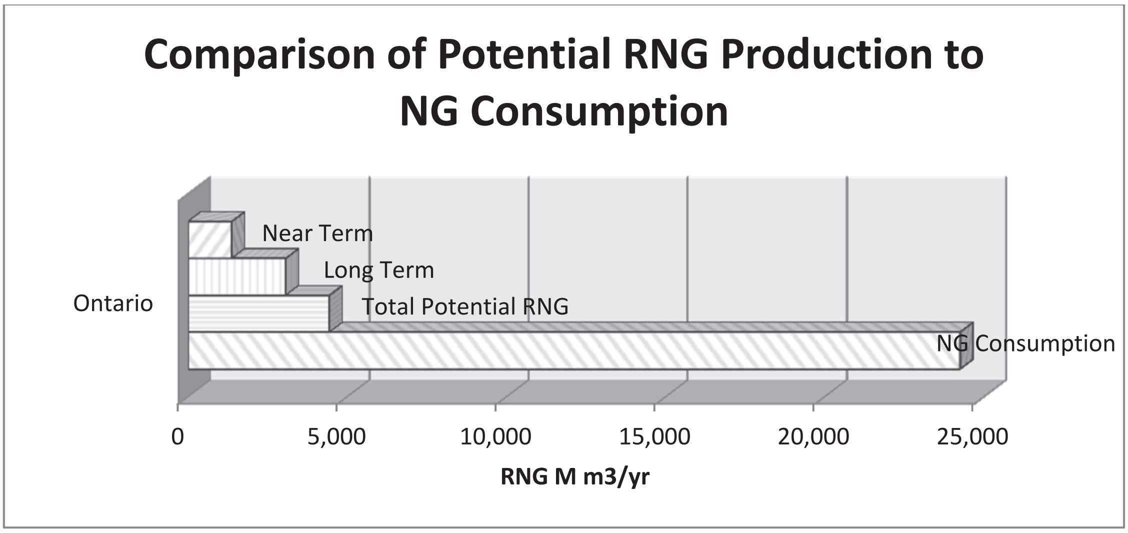


Figure 7. Comparison of Potential RNG Production to NG Consumption

5. GREENHOUSE GAS IMPACT OF METHANE CAPTURE FROM ONTARIO WASTES

The production and capture of RNG from Ontario wastes contributes to GHG reduction through two processes: emission reduction and fuel substitution. Emission reduction can be achieved through the capture of the emitted methane from landfills and the anaerobic digestion of animal manures, in particular hog manures. Figure 8 and Table 17 (Appendix 1) shows the results of our estimates where we assigned a value of 21 times CO_2 for the methane emission reductions. These estimates are based on best case scenario of all landfill gas and 20% of animal manures captured with methane no longer emitted into the atmosphere. Although we are using all landfill emissions to calculate GHG emission avoidance, we recognize that under Ontario regulations, some large landfills will not be permitted to claim carbon credits for the emission avoidance scenario. The manures that are likely to emit methane during storage are those associated with dairy cows and hogs, as these manures are often liquid and thus, stored under anaerobic conditions. Other manures that are stored dry and manures that are applied to land are unlikely to emit significant amounts of methane as these conditions tend to be predominantly aerobic. As shown in Table 7 earlier, only 27% of the methane from the largest landfills is currently captured. However, under government regulations the capture rate at these large landfills will be increasing over the next couple of years.

Fuel substitution applies to the use of RNG to replace any NG produced from fossil fuels. Table 17 and Figure 8 shows the results of our estimates where we assigned a value of 2.87 (NG GHG intensity, t CO_2 eq/t) for fuel substitution (Abboud et al. 2010). The value of 2.87 that we used is similar to the value of 2.79 used in a recent BC report (Electrigaz Technologies, 2008).

Total GHG reductions for Ontario were estimated as 18,984 kt CO_2 eq/yr. Emission reductions contribute slightly more GHG reductions than fuel substitutions in Ontario with 54% of the GHG reductions arising from emission reductions, while the remaining 46% arise from fuel substitution.

5.1 NEAR-TERM GHG IMPACTS FROM ONTARIO WASTES

Of the total GHG reductions, approximately 69% can be realized in the near-term through AD processing of Ontario wastes. This represents 13006 kt CO_2 eq/yr, where

79% of that would be offered through emission reductions and the remaining 21% fuel substitutions.

5.2 LONG-TERM GHG IMPACTS FROM ONTARIO WASTES

Over the long-term, with the development of gasification processes for Ontario wastes, there would be an additional 5978 kt CO_2 eq/yr generated. This represents an additional 31% of the total GHG reductions. All of this amount would be offered through fuel substitutions since technology for emission reductions is available in the near-term.

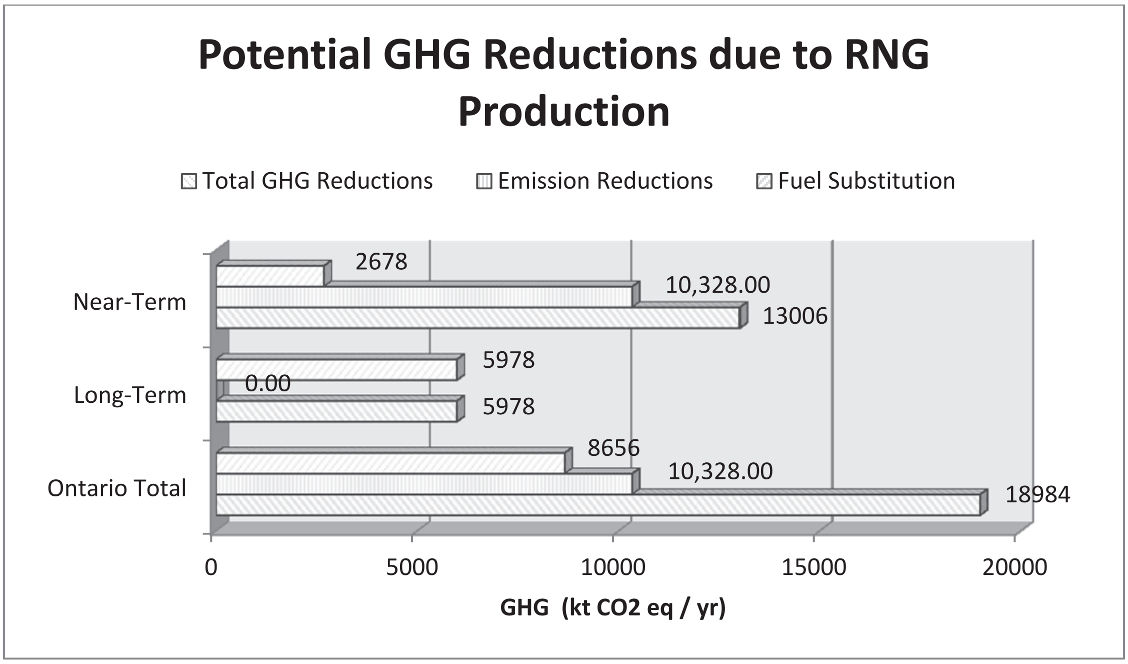


Figure 8. Potential GHG Reductions due to RNG Production

6. EFFICIENCY OF BIOGAS CLEANING COMPARED TO BIOGAS COMBUSTION

The declining reserves of fossil fuels coupled with their rising prices have spurred the development of alternative and renewable fuels and reemphasized the importance of energy efficiency in each energy conversion process. Currently, most biogas generated through AD is used for electricity generation with energy capture efficiencies that vary from 23% to 39% (Electrigaz, 2007) with an average around 35%. The development of more advanced and improved biogas cleaning and separation technologies allows for the production of pipeline grade RNG from biogas with efficiencies varying from 95 to 90% dependent on the raw biogas properties, volume and the type of employed cleaning and separation technologies.

Figure 9 illustrates the wide difference in energy content retention when one uses biogas for generating electricity (35-40% efficiency) versus manufacturing RNG (80-90% efficiency). It is evident that making RNG from existing biogas is a much preferable route energetically as it retains the most energy.

In addition to improving the electric generator output by at least 100% if the raw biogas was used instead to produce RNG, there is another beneficial consideration to be gained by producing RNG for the NG pipeline. This additional volume from energy efficiency represents fuel substitution of fossil fuel that would otherwise have to be provided in order to replace the inefficiency of electricity generation. As a result there are additional GHG emissions produced in electricity generation, which otherwise would be a GHG reduction in the NG pipeline as the RNG is a direct fuel substitution. It is evident that RNG from existing biogas is the preferable route energetically as well as providing the benefit of GHG reductions.

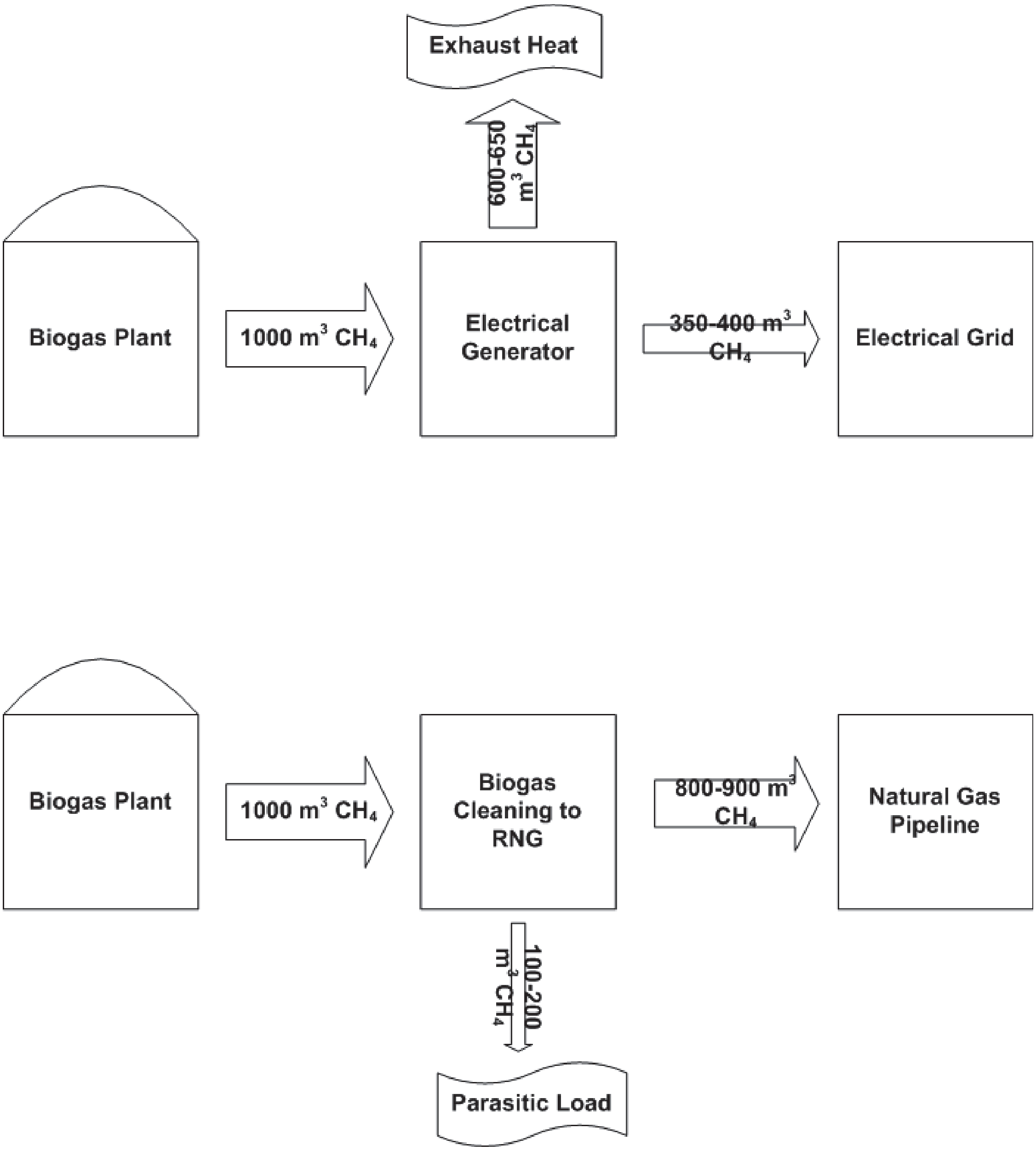


Figure 9. Comparison of Biogas Energy Retained when used for Electricity Generation or RNG.

7. CONCLUSIONS

Production of RNG from Ontario wastes was shown to arise from the application of two well used and understood processes: anaerobic digestion and gasification. Based on our findings, it is envisioned that anaerobic digestion process will be the main source of RNG in the next 5 to 10 years with gasification contributing afterwards. This is based on the availability of the technologies, prior use and acceptance by industry and the need for further technology development activities.

The Ontario wastes which are amenable to producing RNG are those containing significant amounts of biomass and are mostly generated by the agricultural, forestry and municipal sectors.

All of the potential RNG that can be produced from the total Ontario wastes that had been reviewed shows that a potential total of 4435 M m^3/yr of RNG can be produced. Agricultural waste has demonstrated the potential to produce 2643 M m^3/yr (60% of total), followed by 1604 M m^3/yr (36%) from municipal wastes and 188 M m^3/yr (4%) from forestry residues. Anaerobic digestion has the potential to produce 1372 M m^3/yr (31% of total) and represents the near-term potential of RNG production in Ontario. The use of gasification has the potential to produce most of the RNG as we estimated that an additional 3063 M m^3/yr (69% of total) can be produced by this process, however this potential would be realized over the long-term through further technology development.

We compared the relative size of our potential RNG estimates to the current natural gas use for the residential, commercial and industrial sectors. The potential Ontario generation of 4435 M m^3/yr of RNG corresponds to an energy value of 167 PJ/yr or 46,388 GWh of electricity. RNG production can account for a portion of the natural gas use. Within Ontario, our estimate is that if all methane from various wastes were captured, then 18% of current NG residential, commercial and industrial use can be replaced by the produced RNG over the long-term. However, in the near-term the potential Ontario generation of 1372 M m^3/yr of RNG corresponds to an energy value of 52 PJ/yr or 14,444 GWh of electricity and can account for about 6% of the residential, commercial and industrial use of NG. With gasification process capabilities becoming available over the long-term, there would be an additional 3063 M m^3/yr of RNG (115 PJ/yr of energy, or 31,944 GWh of electricity) corresponding to an additional 12% of the current NG consumption in Ontario.

The production and capture of RNG from Ontario wastes contributes to GHG reduction through two processes: emission reduction and fuel substitution. Emission reduction can be achieved through the capture of the emitted methane from landfills and the anaerobic digestion of animal manures. Fuel substitution applies to the use of RNG to replace any natural gas produced from fossil fuels.

Total GHG reductions were estimated as 18984 kt CO_2 eq/yr for Ontario with emission reductions contributing more of the GHG reductions than fuel substitution. About 54% of the Ontario GHG reductions arise from emission reductions, while the rest (46%) arises from fuel substitution.

Results were broken out separately for Union Gas and Enbridge service areas showing that of the 4435 M m^3 RNG potentially produced in Ontario annually, the market potential for Union Gas is 71% of the total (3141 M m^3). The market potential for Enbridge is 29% (1294 M m^3).

In reviewing the Union Gas service area, agricultural wastes (68%) are the largest waste source for potential RNG production, followed by municipal wastes (26%) and then forestry residues (6%). The majority of the RNG volume produced, at 74% would occur through gasification, with anaerobic digestion producing the remaining 26%. Therefore, in the near-term AD processing within the Union Gas area account for 807 M m^3/yr of its total RNG. Of this amount 58% comes from agricultural wastes, and the remaining 42% is generated from the AD processing of municipal waste. Over the long-term, an additional 2332 M m^3/yr (74%) could be generated in this franchise area through the development of gasification process for these waste materials and 72% (1681 M m^3) of this additional RNG could be generated from processing of agricultural wastes, with 20% (468 M m^3) coming from municipal waste materials, and the remaining 8% (184 M m^3) from forestry residues. The Enbridge service area shows that municipal wastes (61%) are the largest waste source for potential RNG production, with the remaining RNG produced from agricultural wastes (38%). There are negligible forestry residues producing RNG in this service area. Although gasification still produces the majority of the RNG at 56%, the anaerobic digestion process is more significant in this service area, due in part to more landfill gas production as well as no forestry residues available for gasification. Therefore in the near-term, AD processing within the Enbridge area accounts for 565 M m^3/yr (44%) of its total RNG and of this amount 80% comes from municipal wastes, and the remaining 20% is generated from the AD processing of agricultural waste. Over the long-term, an additional 729 M m^3/yr (56%) could be generated in this franchise area through the development of gasification process for these waste materials. Of this amount, 53% (387 M m^3) could be generated from processing of agricultural wastes, with 46% (338 M m^3) coming from municipal waste materials. Of the total GHG reductions for Ontario, 18,984 kt CO_2 eq/year, Union Gas service area accounts for 56% of this with 10,704 kt CO_2 eq. The Enbridge service area accounts for 44% of the total Ontario GHG reductions with 8280 kt CO_2 eq.

Within each service area, total GHG reductions were assessed by their constituent values for emission reduction and fuel substitution. Emission reduction values represent the potential methane capture from anaerobic digestion within landfills and from a portion of animal manure, where fuel substitution relates more broadly to the potential of displacing fossil-fuel based NG with RNG produced from all wastes.

It has been shown that Enbridge has proportionately higher emissions reduction potential when compared to fuel substitution. This is a function of population size with associated municipal waste volumes, in addition to factoring in no forestry residues subject to gasification. In the near-term, Enbridge can realize GHG reductions of 6856 kt CO_2 eq/yr, representing 83% of its total potential GHG reductions. Over the long-term, an additional 1424 kt CO_2/yr (17%) of its total potential can be realized with further development of gasification processing.

Union Gas alternatively demonstrates higher fuel substitution potential when compared to emissions reduction. In the near-term, Union Gas can realize GHG reductions of 6149 kt CO_2 eq/yr, representing 57% of its total potential GHG reductions. Over the long-term, an additional 4552 kt CO_2/yr (43%) of its total potential can be realized with further development of gasification processing.

A comparison was made where biogas can be directed into electricity generation, or production of RNG for injection into a natural gas pipeline. There is a wide difference in energy content retention with generating electricity (35-40% efficiency) compared to RNG production (80-90% efficiency). It is evident that making RNG from existing biogas is a much preferable route energetically as it retains the most energy. If the raw biogas is used for RNG cleaning, in addition to improving the electric generator output by at least 100% (800 m^3 methane eq. vs 400 m^3 methane eq.) there is another beneficial consideration to be gained by producing RNG for the NG pipeline. This additional volume from energy efficiency represents fuel substitution of fossil fuel that would otherwise have to be provided in order to replace the inefficiency of electricity generation. As a result there are additional GHG emissions produced in electricity generation, which otherwise would be a GHG reduction in the NG pipeline as the RNG is a direct fuel substitution. It is evident that RNG from existing biogas is the preferable route energetically as well as providing the benefit of GHG reductions.

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APPENDIX 1

Additional Tables

Table 11. Ontario 2009 Crop Production and Estimates of Crop Residues

Crop	Crop Production[1]	Recoverable Residue[2]	Removable Residue[3]
	(kt)	(kt)	(kt)
Soy Bean	2474	3711	1856
Grain Corn	5330	5330	2665
Winter Wheat	1466	249	1246
Barley	285	428	214
Mixed Grains	166	266	133
Spring Wheat	147	192	95.9
Oats	85.1	179	89.5
Total	**9953**	**12598**	**6299**

1 OMAFRA . 2009a. Field crop reporting series.
2 Calculated as Production x multiplier factor (soy bean 1.5; Grain Corn 1.0; Winter wheat 1.7; Barley 1.5; Mixed Grain 1.6; Spring wheat 1.3; Oats 2.1). (Perlack et al, 2005)
3 Calculated as 0.5 x recoverable residue

Table 12. Ontario Production of Cattle and Hog Manures.

	Cattle			Hogs		
	Number[1]	Manure Production		Number[2]	Manure Production	
	(x1000head)	(kg dry/head/d)[6]	(dry Mt/yr)[7]	(x1000)	(kg dry/head/d)[6]	(dry Mt/yr)[7]
Ontario	1827	4.64	0.774	3237	0.564	0.566

1 OMAFRA (2009b). Cattle Statistics.
2 OMAFRA (2009c). Hog Statistics.
3 OMAFRA (2009d). Sheep Statistics.
4 OMAFRA (2009e). Poultry Statistics.
6 Klass (1998)
7 Calculated as number (h) x manure production (kg dry/h/d) x 365 (d/yr) x (kg recovered/kg) x 10^{-6} (Mt/kg). Recovered manure was assumed as: Cattle (25%), Hogs (85%), Sheep (10%) and Chicken (85%) (Ralevic and Layzell, 2006)

Table 13. Ontario Production of Sheep and Chicken Manures.

	Sheep			Chicken		
	Number[3]	Manure Production		Number[4]	Manure Production	
	(x1000head)	(kg dry/head/d)[6]	(dry Mt/yr)[7]	(x1000)	(kg dry/head/d)[6]	(dry Mt/yr)[7]
Ontario	315	0.756	0.0087	45949	0.0252	0.3592

Table 14. Canadian Production of Turkey Manure.

	Turkey Number[5]	Manure Production	
	(x1000head)	(kg dry/head/d)[6]	(dry Mt/yr)[7]
Ontario	3324.9	0.0101	0.0104

5 OMAFRA (2009e). Poultry Statistics.
6 Klass (1998)
7 Calculated as number (heads) x manure production (kg dry/head/d) x 365 (d/yr) x (kg recovered/kg) x 10^{-6} (Mt/kg). Turkey manure that can be recovered was assumed to be 85% (Ralevic and Layzell, 2006)

Table 15. Annual Ontario Municipal Solid Waste (MSW) Production (2005)

	Waste Disposal[1]				MSW Organic Fraction Subject to	
	Residential	Industrial, Commercial & Institutional	Construction & Demolition	Total	AD[2]	Gasification[3]
	(kt/yr)				(dry kt/yr)	(dry t C/yr)
Enbridge	1213.6	1682.3	720.9	3617.2	106.2	465.2
Union Gas	1808.4	2506.7	1074.1	5389	157.8	692.8
Ontario	3022	4189	1795	9007	264	1158

1 Statistics Canada. 2006. This is the difference between waste generated and diverted.
2 Calculated as Column 2 (t/yr) x 0.35 (t solids/t) x 0.25 (t OFMSW subject to AD/t solids). **(Ostrem, 2004)**.
(25% of the Residential waste is amenable to Anaerobic Digestion and the wastes contains 35% solids)
3 Calculated as the MSW biomass fraction that was not converted to biogas plus 50% of the ICI waste (50% solids) and 30% of the CD waste (90% solids). Assumed the waste biomass contains 40% carbon.

Table 16. Potential RNG as a Function of Energy Production and Current Natural Gas Consumption

	Total Potential Methane Generation	Energy	Electricity	NG Consumption[1]	Total Potential Methane Generation
	(M m^3/yr)	(PJ/yr)	(GWh)	(M m3/yr)	(% of NG)
Near-Term	1372	52	14,444	24,250	5.6
Long-Term	3063	115	31,944	24,250	12.6
Total	4435	167	46,388	24,250	18.2

[1] 2010 distribution volume provided by Enbridge: 10,940 M m3; Union Gas 13,300 M m3

Table 17. GHG Reductions Due to Production of Renewable Natural Gas

	Methane		GHG				
	Emission Reduction[1]	Fuel Substitution[2]	Emission Reduction[3]	Fuel Substitution[4]	Total[5]	Emission Reduction[6]	Fuel Substitution[6]
	($M\ m^3/yr$)		(kt CO_2 eq/yr)			(%)	
Enbridge	403	1294	5754	2525.6	8279.6	69	31
Union Gas	320	3141	4573.8	6130.3	10704.1	43	57
Ontario Total	723	4435	10327.8	8655.9	18983.7	54	46
Near-Term	723	1372	10327.8	2677.7	13005.5	79	21
Long-Term	-	3063	-	5978.2	5978.2	0	100

1 Calculated as the CH_4 generated in landfills plus 20% of the CH_4 generated from manure through AD
2 This is the total amount of potential CH_4 generated from all wastes
3 Calculated as column 2 x 21 (GWP)
4 Calculated as column 3 (Mt CH_4/yr) x 2.87 (Mt CO_2 eq/Mt CH_4)
5 Calculated as the sum of columns 4 and 5
6 Calculated as a percent of the total GHG (column 6)

APPENDIX 2

MARKET POTENTIAL FOR SEPARATE FRANCHISE AREAS

MARKET POTENTIAL FOR SEPARATE FRANCHISE AREAS

Enbridge and Union Gas were evaluated separately for market potential based on the following approach. Population data was reviewed on a county basis and allocated to either franchise based upon their service area. The ratio of Ontario population per franchise area was used for RNG calculations for all municipal wastes since that waste stream is directly proportional to the number of people residing in the area.

The other waste materials, including agricultural and forestry residues, had RNG calculations based on Ontario government data provided on a county basis, and allocated to either franchise.

In a limited number of cases, some counties were serviced by both franchises. With these counties, the proportion of population was allocated to each franchise and this ratio was used on the waste volumes for RNG calculations.

It was also determined from the franchises' service directory that two Ontario counties (Haliburton, Manitoulin) and a few other small communities were not serviced by either franchise. As a result the population data was adjusted to remove their numbers from the total census data, including 70,000 people and representing 0.5% of the Ontario population. Statistics Canada (2006) shows census data of 12.09 M Ontario residents (adjusted to remove non-serviced communities). To evaluate the RNG potential broken out by the franchise service areas, it was determined from census data that 7.36 M residents fall within the Enbridge service area, and the remaining 4.73 M residents are within the Union Gas service area. Figure 10 shows that the Enbridge service area includes 61% of the Ontario population with the remaining 39% serviced by Union Gas.

The City of Toronto is an anomaly and represents Ontario's largest city with 2.5 M residents. Previously all solid waste had been shipped by truckload out of Ontario to Michigan. As of January 1, 2011, this waste is being shipped to a Toronto-owned landfill (Greenlane – St Thomas) which resides in Union Gas franchise area. In 2009, 44% of Toronto's residential waste was diverted from landfill through the Blue Bin, Green Bin, Yard Waste and other diversion programs, with this waste remaining within the Toronto area. However for our calculations the other 56% waste volume that was not diverted has been adjusted in the population base franchise area, representing a shift equivalent to 1.4 million Toronto residents (56% of 2.5 M residents) from Enbridge (Toronto) into the Union Gas (St. Thomas) service area, as shown in Figure 11.

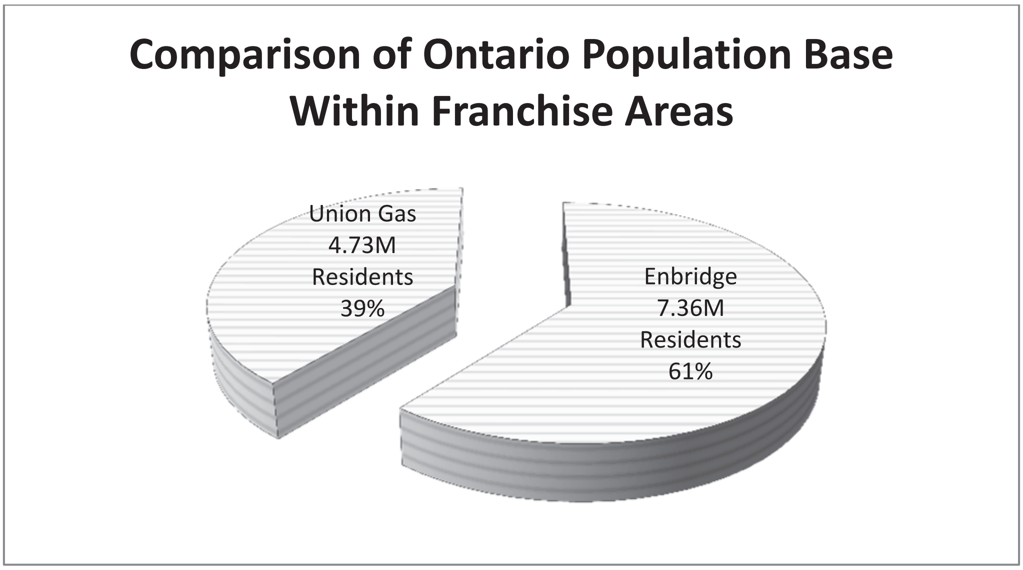


Figure 10. Comparison of Ontario Population Base within Franchise Areas.

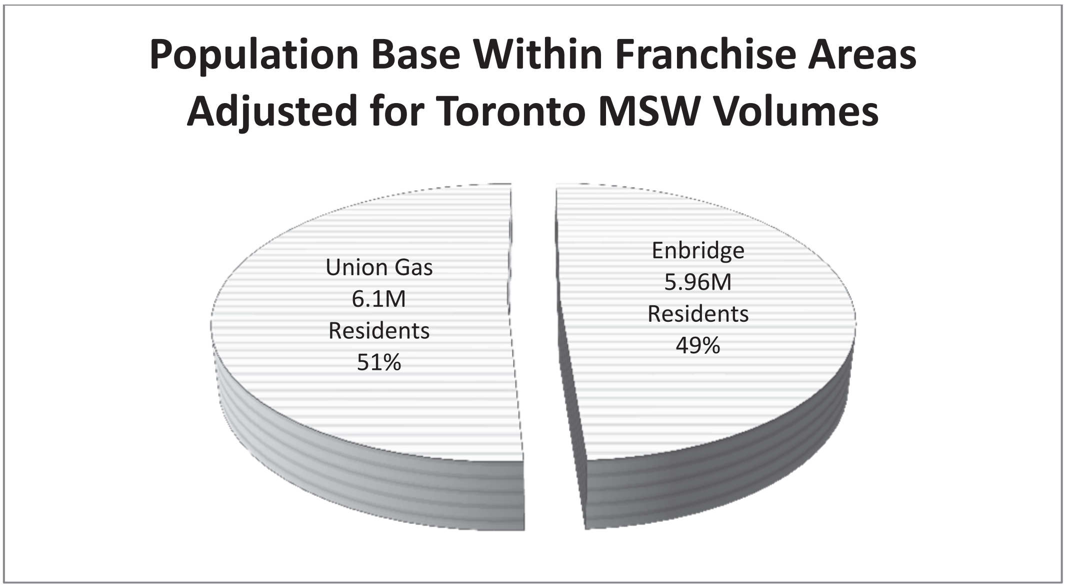


Figure 11. Population Base Within Franchise Areas Adjusted for Toronto MSW Volumes.

In order to calculate the potential RNG production in Ontario, broken out by franchise area, certain assumptions were made. It is assumed that population density is directly related to Municipal Waste volumes (MSW; LFG; Wastewater and Biosolids) and therefore Enbridge RNG will be calculated from the Ontario total RNG production by using a factor of 0.49 for MSW (adjusted population data), and 0.61 for LFG, Wastewater and Biosolids (actual population data). Union Gas RNG calculations will use a factor of 0.51 for MSW, and 0.39 for LFG, Wastewater and Biosolids.

Table 18 and Figure 12 shows that of the 4435 M m^3 RNG potentially produced in Ontario annually, the market potential for Union Gas is 71% of the total (3141 M m^3); with the remaining 29% of the market potential for Enbridge (1294 M m^3).

Table 18. Annual Potential RNG Production from Enbridge and Union Gas Franchise Areas Compared to Total Ontario Wastes

	Agriculture Wastes				Forestry Residues	Municipal Wastes					Total Methane Production
	Manure		Crops			MSW		Landfill	WW	Biosolids	
	Near-Term (AD)	Long-Term (Gas)	Near-Term (AD)	Long-Term (Gas)	Long-Term (Gas)	Near-Term (AD)	Long-Term (Gas)	Near-Term (AD)	Near-Term (AD)	Long-Term (Gas)	
	(M m^3/yr)										
Enbridge	41.2	64	69.1	322	4.85	18.2	297	395	41.5	41.8	1294
Union Gas	156	241	309	1440	184	27.2	441	289	26.6	26.9	3141
Ontario	197	306	378	1762	188	45.6	738	684	68.1	68.7	4435

Note: AD = anaerobic digestion process; Gas = gasification process

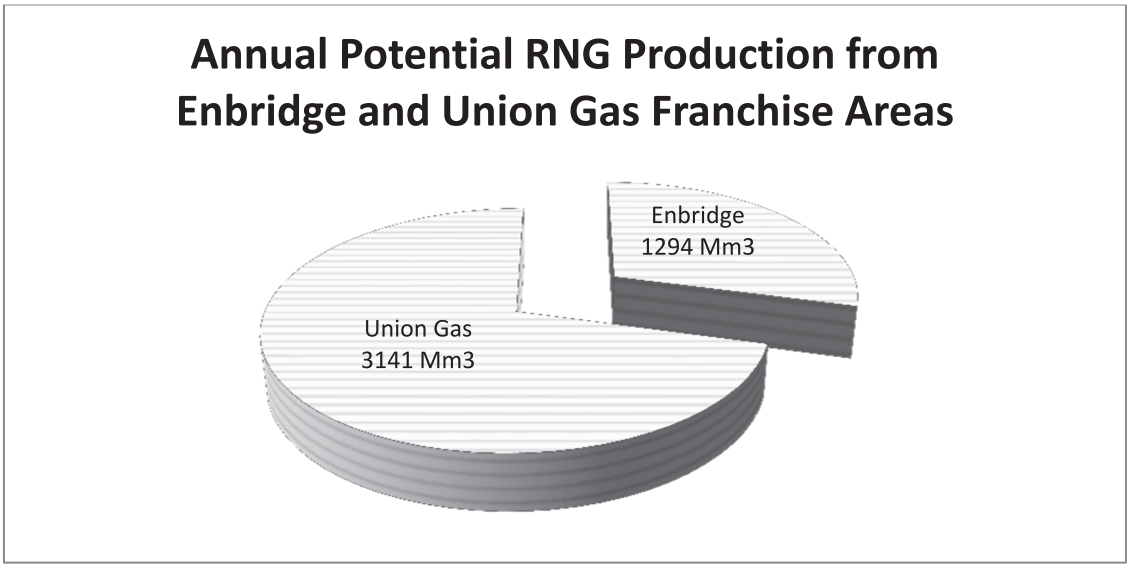


Figure 12. Annual Potential RNG Production from Enbridge and Union Gas Franchise Areas.

Results for Union Gas are broken out separately in Figures 13, 14 and 15, showing that agricultural wastes (68%) are the largest waste source for potential RNG production, followed by municipal wastes (26%) and then forestry residues (6%). The majority of the RNG produced would occur through gasification (74%), with anaerobic digestion producing the remaining 26%.

NEAR-TERM RNG POTENTIAL FOR UNION GAS

In the near-term AD processing of Ontario wastes within the Union Gas area account for 807 M m^3/yr (26%) of the total RNG within this franchise area. Of this amount 58% comes from agricultural wastes, and the remaining 42% is generated from the AD processing of municipal waste.

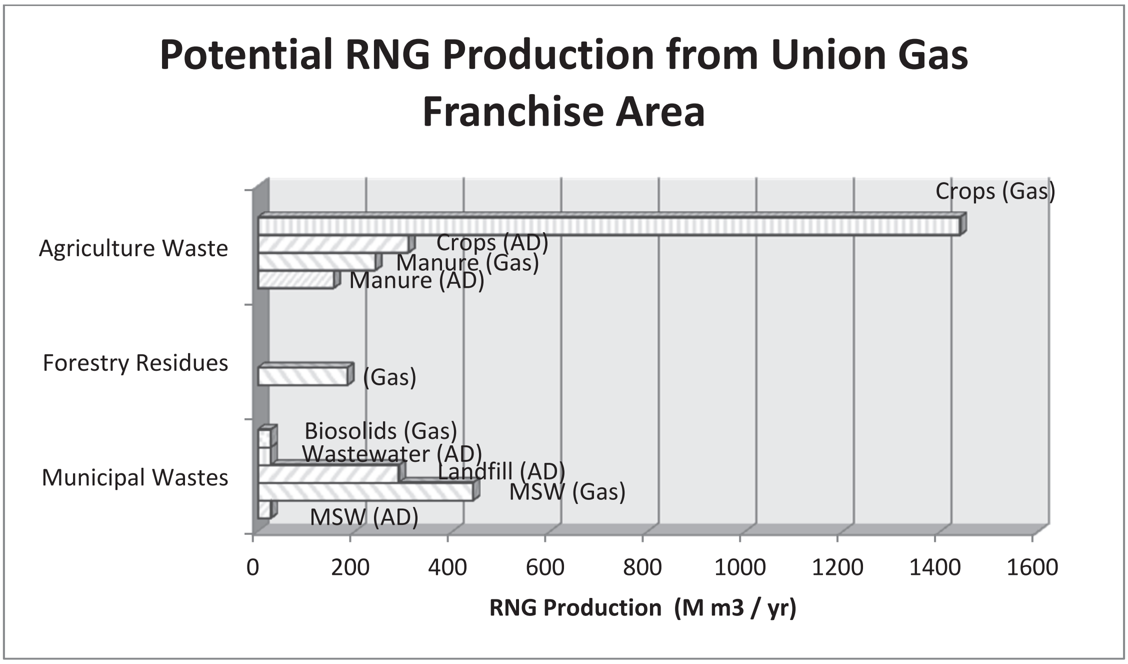


Figure 13. Potential RNG Production from Union Gas Franchise Area

LONG-TERM RNG POTENTIAL FOR UNION GAS

Over the long-term, an additional 2332 M m^3/yr (74% of total potential) could be generated in this franchise area through the development of gasification process for these waste materials. Within the Union Gas area, 72% (1681 M m^3) of this additional RNG could be generated from processing of agricultural wastes, with 20% (468 M m^3) coming from municipal waste materials, and the remaining 8% (184 M m^3) from forestry residues.

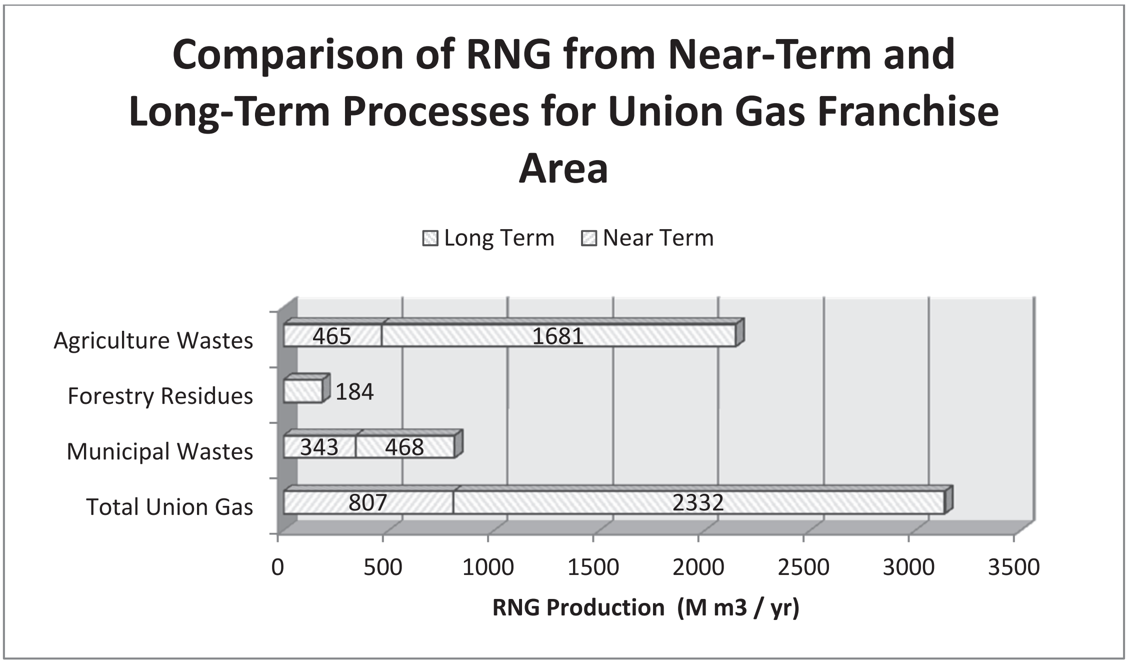


Figure 14. Comparison of RNG from Near-Term and Long-Term Processes for Union Gas Franchise Area.

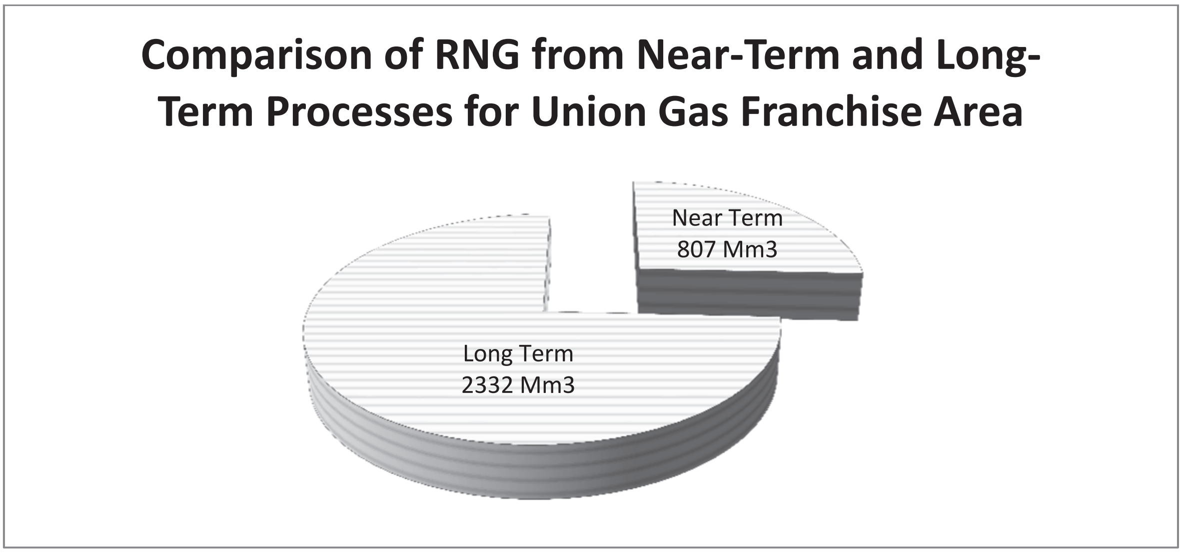


Figure 15. Comparison of RNG from Near-Term and Long-Term Processes for Union Gas Franchise Area.

Results for Enbridge are broken out separately in Figures 16, 17 and 18, showing that in this case municipal wastes (61%) are the largest waste source for potential RNG production, with the remaining RNG produced from agricultural wastes (38%) and negligible forestry residues producing RNG in this service area. Although gasification still produces the majority of the RNG (56%), the anaerobic digestion process (44%) is more significant in this service area, due in part to more landfill gas production as well as no forestry residues available for gasification.

NEAR-TERM RNG POTENTIAL FOR ENBRIDGE

In the near-term AD processing of Ontario wastes within the Enbridge area account for 565 M m^3/yr (44%) of the total RNG within this franchise area. Of this amount 80% comes from municipal wastes, and the remaining 20% is generated from the AD processing of agricultural waste.

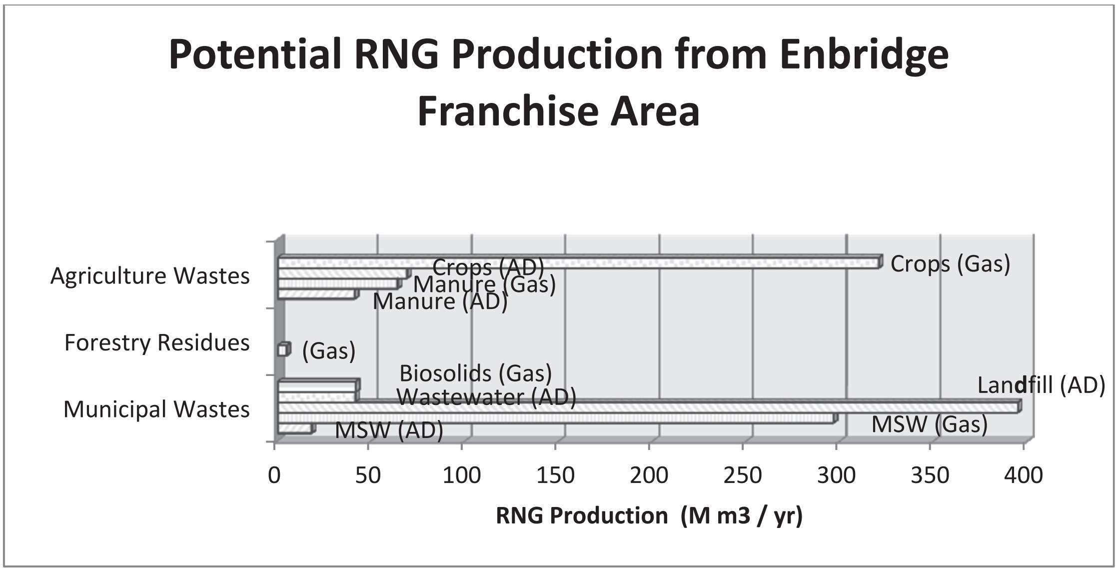


Figure 16. Potential RNG Production from Enbridge Franchise Area

LONG-TERM RNG POTENTIAL FOR ENBRIDGE

Over the long-term, an additional 729 M m^3/yr (56%) could be generated in this franchise area through the development of gasification process for these waste materials. Within the Enbridge area, 53% (387 M m^3) of this additional RNG could be generated from processing of agricultural wastes, with 46% (338 M m^3) coming from municipal waste materials.

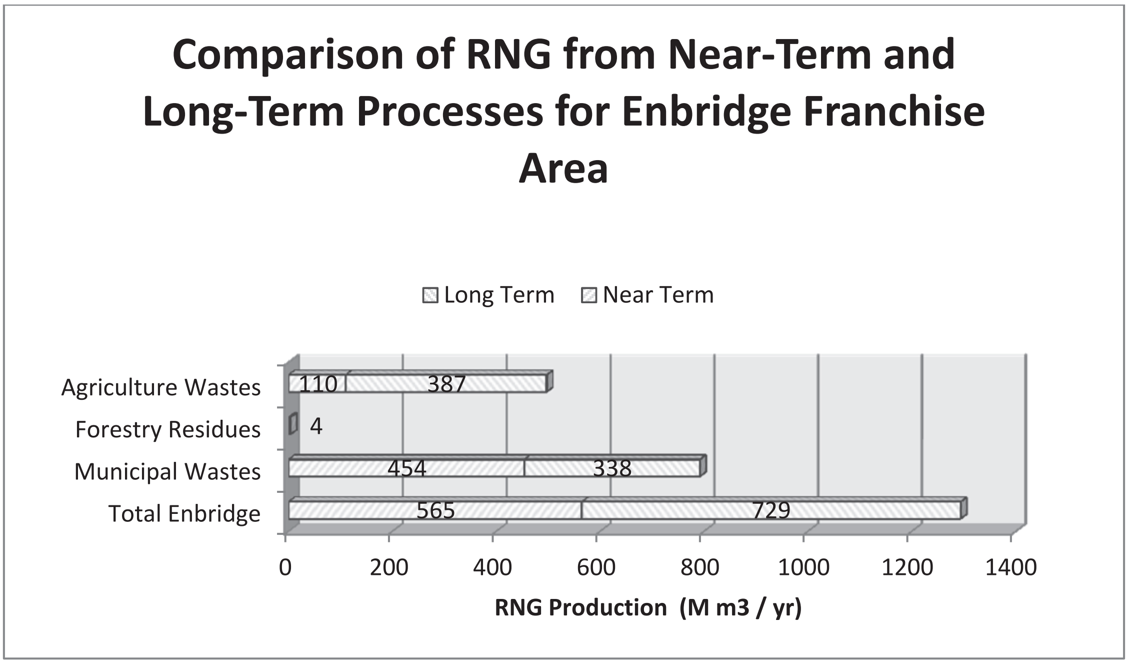


Figure 17. Comparison of RNG from Near-Term and Long-Term Processes for Enbridge Franchise Area.

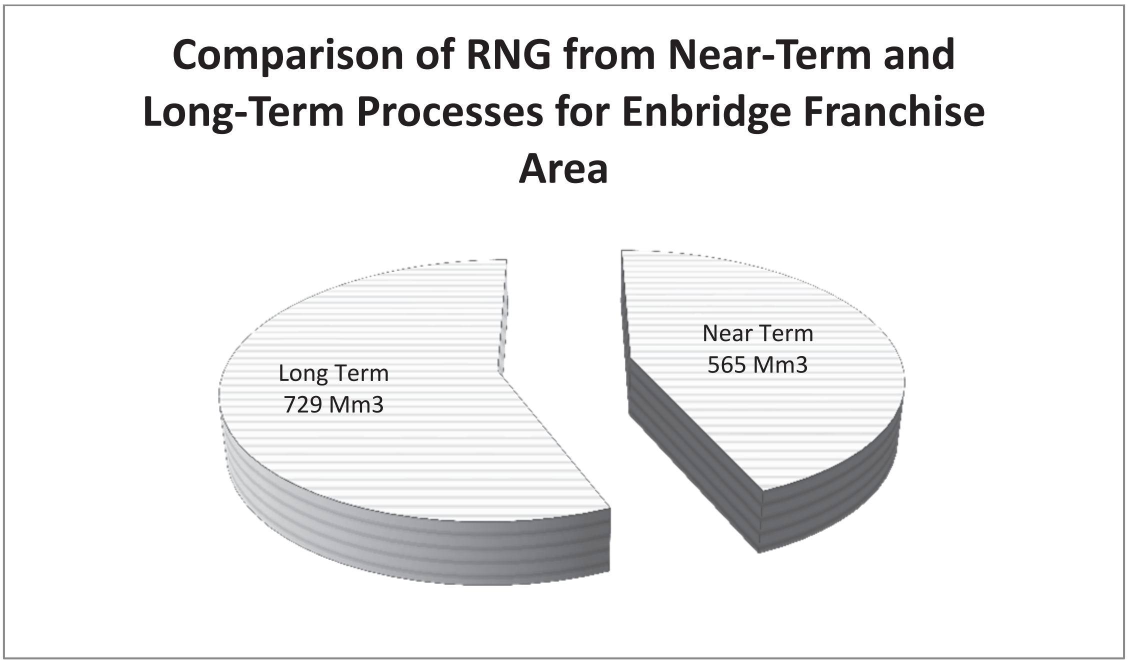


Figure 18. Comparison of RNG from Near-Term and Long-Term Processes for Enbridge Franchise Area.

Calculations for GHG reductions are provided in Table 19, Figures 19, 20 and 21 for Union Gas and Enbridge. Total GHG reductions for Ontario are 18,894 kt CO_2eq/year, with Union Gas service area accounting for 56% of this with 10,704 kt CO_2 eq./yr. Enbridge service area accounts for 44% of the total GHG reductions in Ontario with 8280 kt CO_2 eq./yr.

Table 19. GHG Reductions Due to Production of Renewable Natural Gas within the Franchise Areas

	Methane		GHG				
	Emission Reduction[1]	Fuel Substitution[2]	Emission Reduction[3]	Fuel Substitution[4]	Total[5]	Emission Reduction[6]	Fuel Substitution[6]
	(M m3/yr)		(kt CO_2 eq/yr)			(%)	
Near-Term	403	565	5754	1102.1	6856.1	84	16
Long-Term	-	729	-	1423.5	1423.5	0	100
Total Enbridge	403	1294	5754	2525.6	8279.6	69	31
Near-Term	320	807	4573.8	1575.6	6149.4	74	26
Long-Term	-	2332	-	4551.8	4551.8	0	100
Total Union Gas	320	3141	4573.8	6130.3	10704.1	43	57
Ontario	723	4435	10327.8	8655.9	18983.7	54	46

1 Calculated as the CH_4 generated in landfills plus 20% of the CH_4 generated from manure through AD
2 This is the total amount of potential CH_4 generated from all wastes
3 Calculated as column 2 x 21 (GWP)
4 Calculated as column 3 (Mt CH_4/yr) x 2.87 (Mt CO_2 eq/Mt CH_4)
5 Calculated as the sum of columns 4 and 5
6 Calculated as a percent of the total GHG (column 6)

Within each service area total GHG reductions were assessed by their constituent values for emission reduction and fuel substitution. Emission reduction values represent the potential methane capture from anaerobic digestion within landfills and from a portion of animal manure, where fuel substitution relates more broadly to the potential of displacing fossil-fuel based NG with RNG produced from all wastes.

Figures 19, 20 and 22 demonstrate that within its service area Enbridge has a proportionately higher emissions reduction potential when compared to fuel substitution. This is a function of population size with associated municipal waste volumes, in addition to factoring in limited forestry residues subject to gasification. In the near-term, Enbridge can realize GHG reductions of 6856 kt CO_2 eq/yr, representing 83% of its total potential GHG reductions. Over the long-term, an additional 1424 kt CO_2 eq/yr (17%) of its total potential can be realized with further development of gasification processing.

Figures 19, 20 and 23 demonstrate that within its service area Union Gas alternatively demonstrates higher fuel substitution potential when compared to emissions reduction. In the near-term, Union Gas can realize GHG reductions of 6149 kt CO_2 eq/yr, representing 57% of its total potential GHG reductions. Over the long-term, an additional 4552 kt CO_2/yr (43%) of its total potential can be realized with further development of gasification processing.

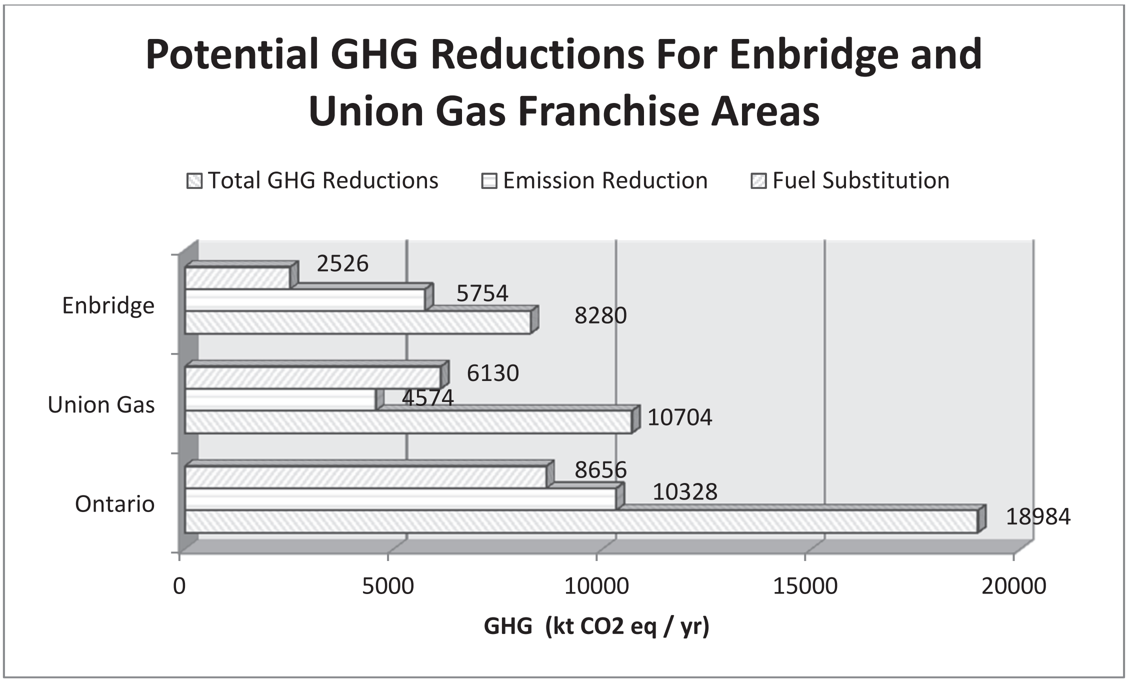


Figure 19. Potential GHG Reductions for Enbridge and Union Gas Franchise Areas

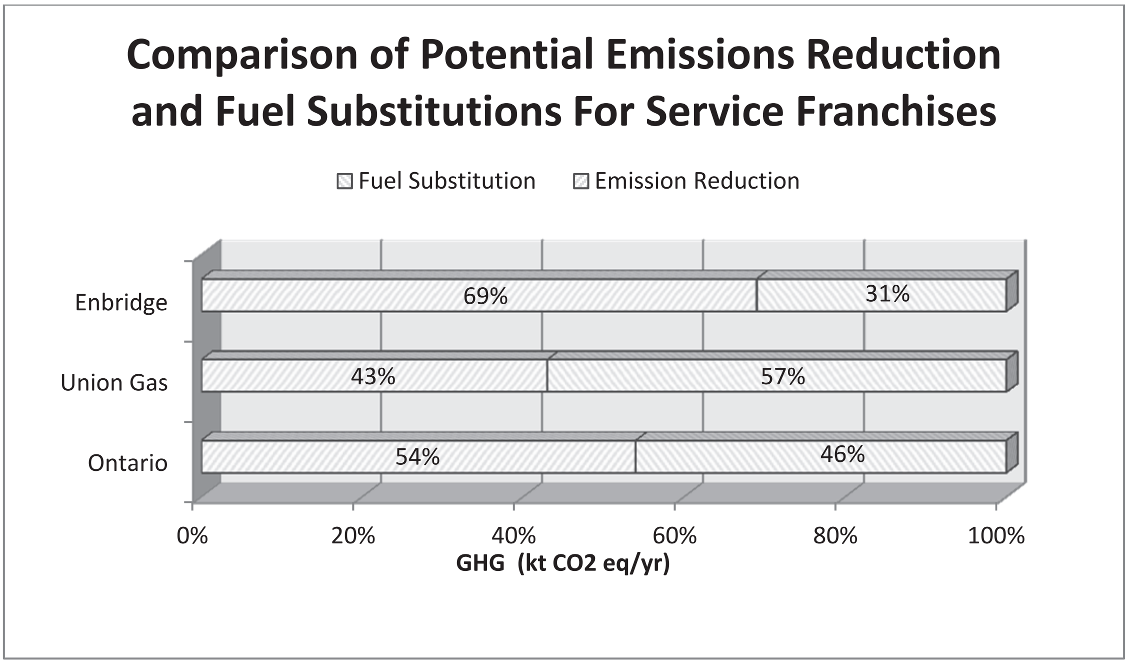


Figure 20. Comparison of Potential Emissions Reduction and Fuel Substitutions for Service Franchises.

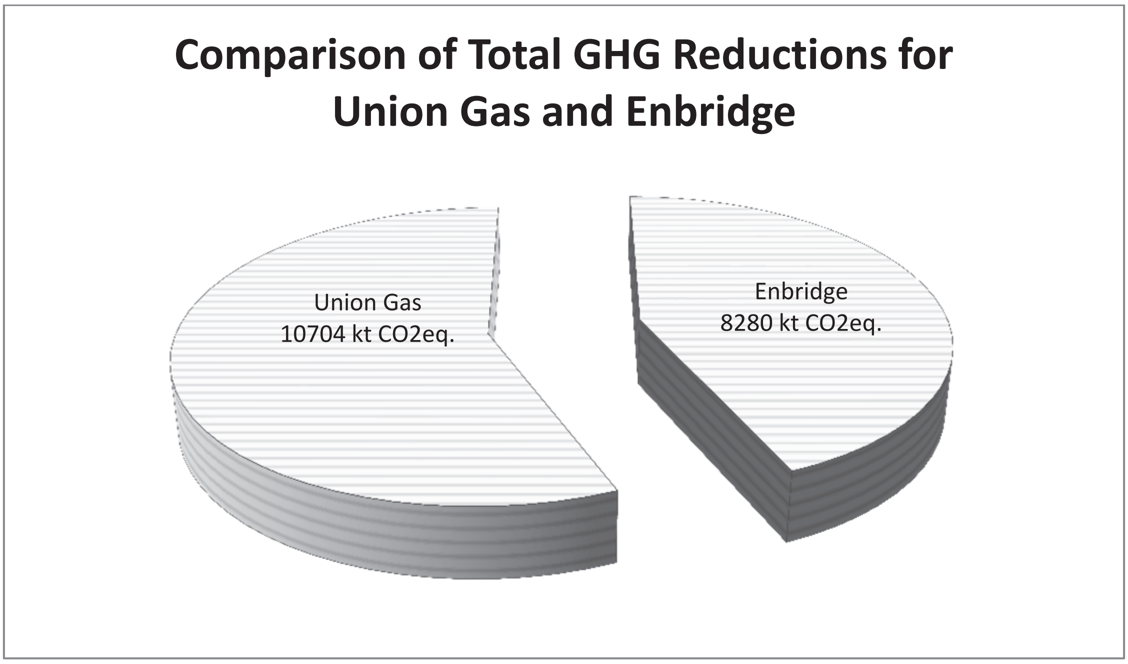


Figure 21. Comparison of Total GHG Reductions for Union Gas and Enbridge

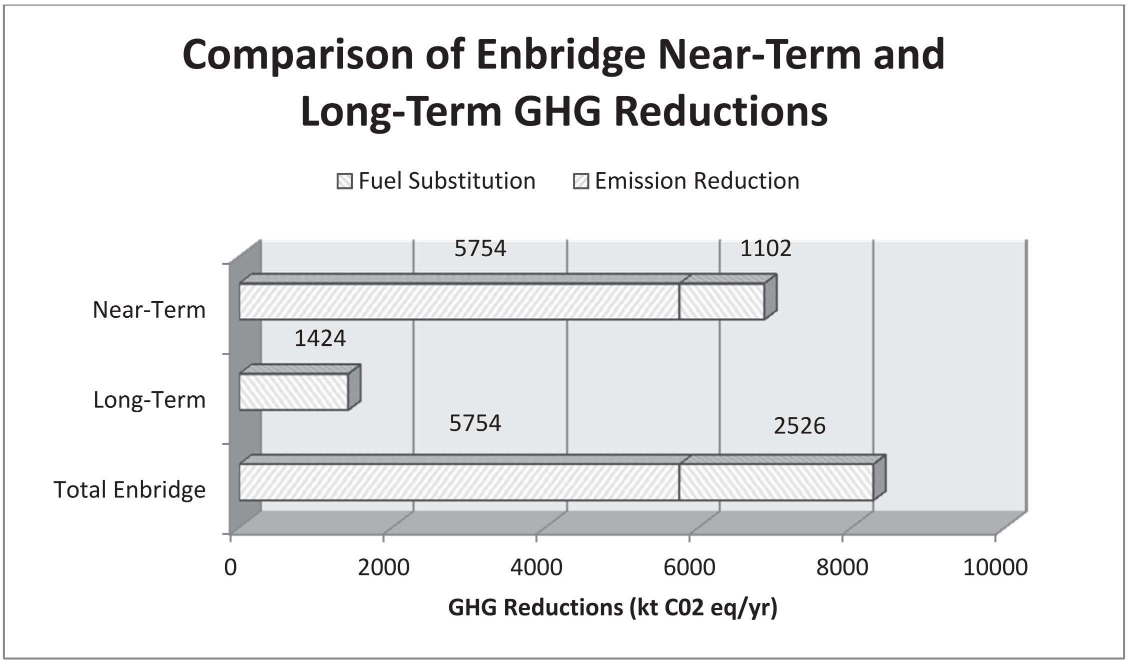


Figure 22. Comparison of Enbridge Near-Term and Long-Term GHG Reductions.

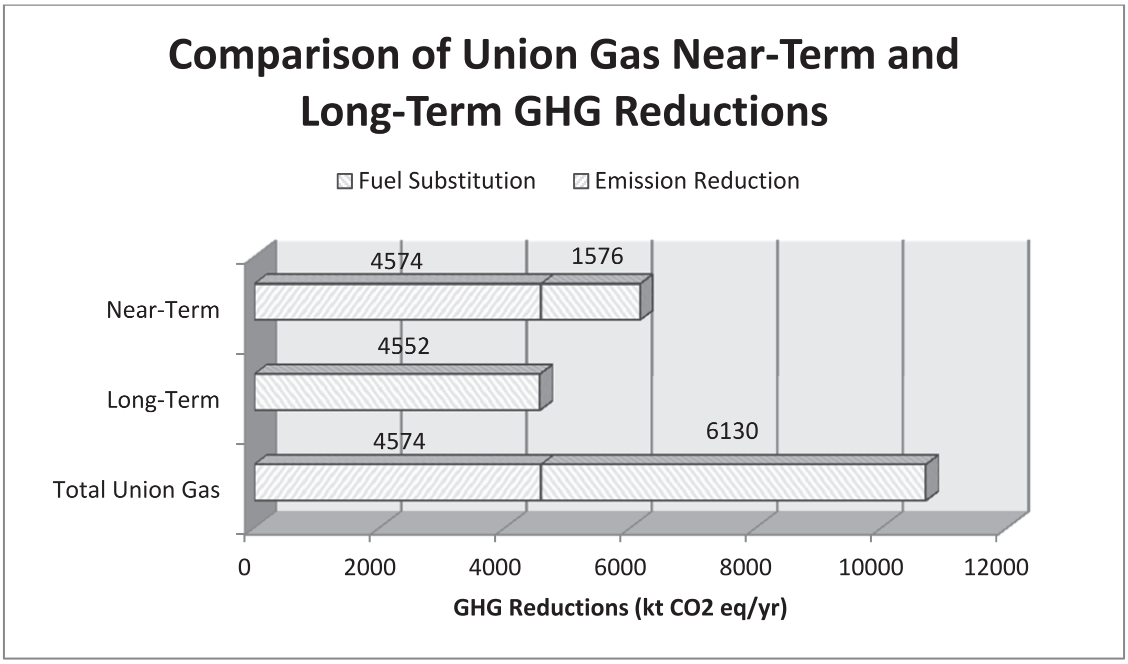


Figure 23. Comparison of Union Gas Near-Term and Long-Term GHG Reductions.

In considering the volumes of MSW generated, landfill gas is a potentially harmful emission from MSW. In addition to the greenhouse gas impact of methane capture outlined above, and converting it into a reliable energy source, the capture and use of LFG provides co-benefits of limiting odours, controlling damage to vegetation, reducing owner liability, risk from explosions, fires and asphyxiation while providing a potential source of revenue and profit. Furthermore, the combustion of landfill gas destroys volatile organic compounds, which reduces smog formation.

Methane is a potent greenhouse gas. Its contribution to global warming is 21 times that of carbon dioxide. Landfills are responsible for almost 40% of anthropogenic methane emissions in North America. The volatile organic compounds in these gases interact with nitrous oxides to form ozone, a primary cause of smog. Methane is also potentially hazardous since it is explosive in concentrations between 5 and 15 percent by volume.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Ex. 3, Tab 4, pages 17 – 24

Question:

a) Please list all facilities (and organizations) that Union has identified as potentially being in a position to enter into an RNG supply contract with Union.
b) Of those, please provide a list of those which are currently venting methane to the atmosphere without capture or flaring.
c) Of those, please provide a list of those which would be required by government regulations to capture and/or flare their methane emissions within the next five years regardless of whether they enter into an RNG supply contract.
d) Please provide an estimate of the percent of the RNG supplies (i.e. % of m3/yr) that could be contracted for over the next 10 years that will result in the capture of methane emissions that would otherwise be released to the atmosphere without flaring. If a single estimate is not possible, please provide a range of potential, including any caveats and a discussion.

Response:

a) Please see the response at Exhibit B.Energy Probe.2 f), Attachment 8, p. 2.

b) No facilities referenced are currently venting methane without a flare with the exception of agricultural projects.

c) Ontario Regulation 232/98 ("O. Reg. 232/98") and Revised Regulations of Ontario 1990, Regulation 347 (General Waste Management) ("Regulation 347") under the Environmental Protection Act (EPA) require landfill gas collection and flaring (burning), or use, for new, expanding and operating landfills larger than 1.5 million cubic metres. For facilities that are not yet constructed or permitted, it is unlikely that an environmental permit would be issued allowing methane to vent to atmosphere. Farming operations do not have legislation to capture or flare their methane emissions.

d) See Exhibit B.Energy Probe.2 f), Attachment 8, p. 2 for a list of facilities that could produce RNG in the province which was sent to the MOECC. Union's RNG proposal contemplates contracting for supplies within the next two years. Union currently cannot estimate a range of volumes that could be contracted over the next 10 years.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Ex. 3, Tab 4, pages 17 – 24

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

Response:

Union is seeking approval for the use of its proposed RNG funding mechanism for as long as government funding is available to support the economic acquisition of RNG by gas utilities in Ontario.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Ex. 3, Tab 4, pages 17 – 24

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

Response:

Please see the response at Exhibit B.ED.4.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Ex. 3, Tab 4, pages 17 – 24

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

GHG emissions reductions may arise from (a) the displacement of conventional natural gas and (b) the capture of methane that would have been vented to the atmosphere as fugitive emissions.

If the $/tonne estimate includes GHG emissions reductions arising from avoided fugitive methane emissions, please (a) provide the underlying calculations and (b) also provide an estimate that does not include the GHG emissions reductions from avoided fugitive methane emissions.

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

Response:

Please see the response at Exhibit B.ED.5.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Ex. 3, Tab 4, pages 17 – 24

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

Response:

Please see the response at Exhibit B.ED.4.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Ex. 3, Tab 4, pages 17 – 24

Question:

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

Response:

a)–c) Please see the response at Exhibit B.Staff.6 d).

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Ex. 3, Tab 4, pages 17 – 24

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

Response:

Union is not privy to the details of any specific RNG procurement program in California. Union understands that in California RNG is predominantly being used for transportation, displacing diesel fuel consumption. Contracts are struck between RNG producers and transportation fuel providers in a competitive marketplace with confidential contract terms. The references included in Exhibit B.Staff.5 were for RNG and biogas procurement to use as a renewable fuel to generate electricity as part of California's Renewable Portfolio Standard ("RPS"). California's RPS has a target of obtaining 50% of the state's electricity from renewable energy sources by 2030. In contrast, Union's RNG proposal is designed to support the Ontario government's Climate Change Action Plan's action item of reducing emissions from fossil-fuel use in buildings and thermal processes. Because the California transportation RNG fueling market is fundamentally different than Union's RNG proposal, it is not appropriate to compare the two.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: General

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

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

Question:
Please adopt/confirm EGDI response and/or an additional specific response related to Union's C&T Application.

Response:

Union and EGD have requested OEB approval to amalgamate effective January 1, 2019 under EB-2017-0306. The companies will continue to operate as separate utilities until the OEB approves the amalgamation and it becomes effective. Although the companies will continue to operate separately, Union and EGD are committed to working together wherever possible to reach alignment with regard to their respective RNG proposals. Please see the response at Exhibit B.CCC.11.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit 3, Tab 4, Page 17

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

Question:

a) Please provide/file a copy of the referenced Navigant Report
b) Provide a copy of Union Gas Limited's Long-Term Energy Plan Review submission, December 16, 2016,
c) Provide references to any other reports/documents that Union has relied upon in preparation of its Plan.
d) Please provide/file a copy of the referenced Minister Thibeault's Letter of December 10, 2016
e) Please provide a copy of the relevant extract(s) from the OEB "Gas Supply Framework".
f) Please provide a Summary schedule/list of meetings with MOECC and OEB Staff on RNG Procurement. Include main topics discussed and specific documents provided by the parties.

Response:

a) Union assumes this question refers to EGD's 2018 Compliance Plan, Exhibit C, Tab 5, Schedule 2, p.4 of 29, whereby the Fuels Technical Report prepared by Navigant Consulting Inc. is referenced. While Union is familiar with this report Union did not reference the Navigant Report in its 2018 Compliance Plan.

   Further, because EGD received a similar interrogatory request from Energy Probe, Union will defer to EGD to respond.

b) Please see Attachment 1.

c) In completion of its RNG proposal, Union referred to the OEB Marginal Abatement Cost Curve ("MACC") recognizing, as acknowledged in the MACC report itself,[1] that the RNG studies used in the formation of the MACC are dated and in some cases limited in detail.

[1] OEB MACC, p. 52

In the development of its illustrative example of the RNG funding mechanism,[2] Union utilized the natural gas forecast that can be found at Exhibit B.Energy Probe.6 a). Union also utilized the OEB Long Term Carbon Price Forecast for carbon price assumptions.

Union and EGD also developed their RNG proposals based on discussions with and feedback resulting from provincial ministries, particularly the Ministry of the Environment and Climate Change and Ministry of Energy. The correspondence from these discussions is provided at Exhibit B.Energy Probe.2 f).

d) Please see Attachment 2.

e) Please see Attachment 3.

f) Please find below a list of meetings with MOECC since the Spectra-Enbridge merger close in February 2017, where Renewable Natural Gas was the primary focus. These meetings included representatives from both Union and EGD.

- Multiple Meetings during February 2016 – Union RNG Program Submission – Please see Attachment 4.
- March 30, 2016 – Joint Canadian Biogas Association, Union and Enbridge Meeting with various Ministries – Attachment 5 and Attachment 6.
- June 7, 2017 – Enbridge Presentation at the Ministry of Environment's Organics Working Group on RNG – Please see Attachment 7.
- June 21, 2017 - Enbridge Gas & Union Gas meeting with Ministry of Environment regarding the Landfill Gas Protocol
- July 26, 2017 – Enbridge Gas & Union Gas meeting with Ministry of Environment and Ministry of Energy regarding RNG – Please see Attachment 8.
- August 29, 2017 - Enbridge Gas & Union Gas meeting with Ministry of Environment regarding RNG – Please see Attachment 9.
- November 15, 2017 - Enbridge Gas & Union Gas meeting with the Ministry of Energy and Ministry of Environment – Please see Attachment 10.
- November 22, 2017 – Enbridge Gas & Union Gas submitted a list of RNG-ready projects to the Ministry of Environment and Ministry of Energy – Please see Attachment 11.
- December 12, 2017 - RNG Technical Meeting with MOECC & OMAFRA
- January 9, 2018 – Enbridge Gas & Union Gas submitted a Draft RNG Discussion Document to the Ministry of Environment – Please see Attachment 12.

[2] Exhibit 3, Tab 4, pp. 20-21

uniongas
A Spectra Energy Company

Dear Minister Thibeault,

On behalf of Union Gas, our 2,200 employees and our 1.4 million Ontario customers, I would like to commend you, your ministry and the Ontario government as a whole on your determination to move this province toward a lower emission future.

I want to take this opportunity to reiterate that Union Gas supports this goal and we welcome the opportunity to continue to work collaboratively on achieving it, such as by offering the attached submission as your ministry considers the next iteration of Ontario's Long-Term Energy Plan.

As one of Ontario's premier energy solution providers, with more than 100 years of experience, it is our considered position that the province's lower-carbon goal must be approached in a manner that balances the environment, the economy, and affordable energy for Ontarians.

This balance between the environment, the economy and affordability is crucial to protect and grow jobs, support industrial and small businesses and ensure sustained economic growth in a lower emission future.

Investing in the affordable energy we deliver, coupled with available and proven technologies, will not only help Ontarians manage their energy costs, but also help Ontario achieve its emissions goals and create the conditions for the innovations that are critical to ensuring our economy will flourish in a lower emission future.

To start, there is an array of ready-to-implement solutions, such as: renewable natural gas, which can help "green" our existing natural gas supply; compressed natural gas, which can lower costs and emissions in the transportation sector; and combined heat and power systems, which can leverage our existing natural gas infrastructure and increase the flexibility of the existing electricity grid. We also have an outstanding track record of helping our customers use less energy through decades of demand side management programs.

In addition, there is a wide range of energy innovations that are close to commercial viability that require investment and partnerships to advance. Union Gas is proud to have started to work with several ministries on some of these initiatives and we look forward to collaborating with government on new opportunities in the future. There's no question that continued investment in innovation will be key to supporting continued growth in a lower-carbon economy.

Union Gas greatly values the long-standing tradition of collaboration with government. We offer the attached submission in that tradition, and look forward to continuing to work together to help achieve a balanced energy system and a bright lower-carbon future for Ontario.

Sincerely,

Steve Baker
President
Union Gas Limited

Long-Term Energy Plan Review Submission

Prepared by
Union Gas Limited
for the Minister of Energy

12/16/2016

unionGas
A Spectra Energy Company

SUBMISSION SUMMARY

Our submission is structured according to the format used during the Long Term Energy Plan Open Houses *(Innovation, Energy Supply/ Delivery, Conservation/Efficiency and Energy Prices)* and recognizes the need to strike a balance between the environment, the economy, and affordable energy.

The highlights of our submission are included below:

1. Union Gas supports the province's goals of moving towards a lower emissions environment, and believes it should be approached in a manner that balances environment, the economy, and affordable energy.
2. Energy prices and certainty are key economic drivers. Consideration of the cost and capacity impacts to electrify the province's energy requirements as described in the CCAP should be outlined in the LTEP to ensure they are understood by stakeholders and managed accordingly.
3. If the Ontario government chooses to convert homes from natural gas to electric heat (and require new homes to be electric rather than affordable natural gas), Union has offered an integrated solution that obtains 60% of the carbon reduction at significant savings.
4. The 2017 LTEP should designate additional funding to the expansion of natural gas to remote areas of the province to provide affordable energy to these areas and replace higher emission alternatives.
5. The LTEP should address the technology and infrastructure stalemate for Compressed Natural Gas (CNG) that currently exists in Ontario by deploying both the engine conversion incentives and funding for CNG refueling stations as identified in the CCAP in Q1 2017. Alignment between federal and provincial funding would further enhance this market development and optimize all sources of funding.
6. In early 2017, the province should provide direction to the Ontario Energy Board (OEB), requiring Renewable Natural Gas (RNG) to be included in the supply portfolio of natural gas utilities. A regulatory proceeding through the OEB will need to be completed in a streamlined fashion to revise the natural gas supply framework and initiate market development.
7. Combined Heat and Power (CHP) should be recognized as part of the energy portfolio in Ontario moving forward and take advantage of the economic and environmental benefits of doing so. The IESO approved CDM programs rely on CHP as an important and affordable option to meet electric conservation targets.

uniongas

"Natural Gas will continue to play a critical role in the energy mix in Ontario"

Premier Kathleen Wynne

INTRODUCTION

Union Gas supports the province's goals of moving towards a lower emissions economy, while growing the Ontario economy and providing consumers with affordable energy. Union believes that natural gas plays an essential role in realizing these goals and they will only be achieved if the province and stakeholders move towards a lower emissions economy in a manner that balances the environment, the economy, and affordable energy for Ontario. This balance is crucial to protect and grow jobs, support industry and small business, ensure sustained economic growth that funds our social safety net and also protect consumers from unnecessary energy costs. With increasing concerns about escalating electricity prices, the tie between policy and economic growth is more apparent, as is the need for effective, fact-based, practical solutions.

Contained within this submission are further details and suggested solutions to help achieve this balance. Some of the alternatives highlighted are already in progress and Union Gas is working with the province on them. Others are new and will require additional consultation. Union Gas looks forward to the release of the Long Term Energy Plan (LTEP) and greatly values the long standing tradition of collaboration with the government. We look forward to working together to help the government achieve a balanced LTEP.

ENERGY AFFORDABILITY

As outlined in the Navigant Fuels Technical Report (FTR), diversity of energy supply and flexibility are critical to meet the demands of the province moving forward and achieving GHG reduction targets. Natural gas has been, and will continue to be, a significant part of the energy portfolio for the province of Ontario.

In fact, in 2015 natural gas;

RESIDENTIAL

Supplied approximately 80%[1] of the residential sector heating and water heating load.

COMMERCIAL

Fueled over 90%[2] of the total commercial energy needs in Ontario.

PROVINCIAL

Provided nearly 40%[3] of the province's industrial energy

ELECTRICITY GENERATION

Accounted for about 10% of Ontario's electricity production and 25% of the province's installed electricity generating capacity.[4]

Not only does natural gas serve a much higher proportion of the energy needs in Ontario than electricity, it does so at a fraction of the cost. In 2015, the per unit cost of natural gas is about 20% of the cost of electricity.

Figure 1: Summary based on ICF Electrification Study November 2016

	Peak Capacity	Book Value (2015)	Annual Energy (2015)	Annual Cost (2015)	Per Unit Cost
Natural Gas	~80 GW Winter Peak	$16.3 billion	270 TWh	7.7 billion	$30/MWh, or $0.03/KWh
Electricity	~25 GW Summer Peak	$70-75 billion	142.5 TWh	20.5 billion	$142.5/MWh, or $0.14/KWh

As illustrated in the table above, natural gas provides 3 times the peak capacity of electricity, and serves more than double the annual energy consumption all at a fraction of the per unit cost of the electricity system. These facts demonstrate that when developing the next LTEP, it is important for Ontario to consider the role that both natural gas and electricity play in the province. Natural gas is critical to safely and reliably, serving heating and process loads across all sectors of the economy, including electricity production. It serves these sectors all year around, but also at those most critical points during the winter when heating load is essential to the health and wellbeing of Ontarians and it does so at a cost that is affordable to business, industry, and consumers alike.

The province should use the lens of energy affordability when outlining actions in the upcoming

[1] Navigant Fuels Technical Report (September , 2016), page 17
[2] Ibid, page 21
[3] Ibid, pg.21
[4] Ibid., pg. 7

LTEP. Key considerations to managing energy affordability and prioritizing actions related to reducing greenhouse gas emissions should include;

- The short and long term cost projections of electricity, including the generation, transmission, and distribution costs resulting from the electrification of segments of Ontario's economy.
- Leveraging existing energy infrastructure as opposed to building new.
- The cost per tonne of carbon abatement of various solutions. Abatement opportunities must be prioritized and those that are the least cost should be developed first.
- Maintaining a diversified energy portfolio.

ICF has recently completed an analysis of electrification (including costs) for single family homes, similar to the IESO Ontario Planning Outlook (OPO) scenario for Outlook D (but ICF focused only on single family homes while the IESO looked at measures across the full Ontario economy). The ICF analysis is based on a different approach and some different assumptions than the IESO OPO report, and did result in some complementary outcomes as well as some that differ (full report in attached addendum).

The ICF study determined that 50% of equipment decisions by 2035, as referenced in Outlook D of the OPO report, **will equate to approximately 25% of homes (~790,000)** in the province converting from natural gas to electricity. The conclusion of the ICF work is that even partial electrification of homes **(such as the 25% by 2035) would call for significant addition of generating capacity as well as transmission and distribution infrastructure and materially impact the price of electricity.**

Specifically, the ICF study found that:

- Conversion of 790,000 homes would require **11.8 GW of additional peak capacity**, or 16-21 GW of new installed capacity.
- The impact of conversion of 790,000 homes is the same winter peak capacity impact that the IESO OPO report (Outlook D) found, but for an economy wide suite of electrification measures. Therefore, the initial high level peak capacity impact in the OPO report appears to be understated.
- The additional 11.8 GW of peak capacity would **add $10-$12 billion of incremental cost <u>per year</u> to the electrical system**. This system cost does not include the full impact on the distribution systems (especially those in high density areas) and does not include the incremental capital cost for consumers to buy new electric driven home heating technology.
    - The impact of this measure on system cost, where imposed evenly to approximately 5,000,000 Ontario households could equate **to an increase of over $2000/year for each household.** The cost per household would be **significantly higher** if the costs were allocated only to the 790,000 homes that were electrified.
- The additional installed capacity is required only at peak times, even where this capacity is leveraged to charge an assumed 2.4 M electric vehicles. The resulting utilization rate would be ~ 10% over the year (15-20 TWh of energy).
- Because of the low utilization rate due to the significant winter peak that would need to be met, the per unit cost of added peak capacity could be very expensive: **$500-$600/MWh. This is about 3-4 <u>times</u>** the current per unit cost of $142.5/MWh.
- The cost of abatement for converting from natural gas to electricity (assuming air-source heat pump for space heat and water heating) **is $380/tonne C02e**. This far exceeds the estimated carbon price of $18 for 2017 or projections of $200 by 2035[5].

Beyond the significant cost impacts of converting 25% of single family homes

[5] Per Enviroeconomics Study

to electricity, there are other practical considerations in terms of how such conversion could be executed. In order to meet GHG emissions targets, the incremental peak capacity required would need to be from non-emitting sources.

Given various barriers, including time, it would be a challenge to install 11.8 GW of nuclear power by the time it is needed in 2030 **(the equivalent of 2 Bruce Nuclear Plants)**. The challenge associated with this would be compounded when the Pickering Nuclear Plant goes off-line for refurbishment in 2022, removing an additional 3 GW of installed capacity.

Wind and solar power could be installed, but would require backup sources of supply, which would either be natural gas fired power (and not support GHG emissions goals), or large scale implementation of new technologies such as energy storage. These technologies will not likely be viable on this scale within this timeframe, and will add incremental cost. Imports may be another possible source, however, Quebec does not have excess winter peak capacity, which is what would be required to meet Ontario's requirement. Import alternatives from the US northeast would be based on natural gas fired power, and therefore would not be non-emitting thereby defeating the purpose while at the same time negatively impacting the ontario economy to the benefit of the us. Finally, Ontario may look to existing excess off-peak power to serve these loads. However, by definition this energy would not be available to meet the requirement on the winter peak.

Although the ICF Report and the IESO OPO Report relied on some differences in approach and assumptions, both provide valuable insights and complimentary outcomes related to the significant impact of electrification on the winter peak. **An increase in peak capacity of ~11GW would be unrealistic from both a cost and practical perspective.**

Union Gas recognizes that the current CCAP is not proposing full-scale economy wide electrification at this time and this scenario was also not contemplated in either the IESO OPO or the FTR. However, these studies did contemplate a scenario (Outlook D) that projected 50% of residential and commercial equipment decisions as well as 10% of industrial equipment decisions by 2035 will be electrical, where as they are natural gas today. While the studies focused on the technical implications of such conversion (impact on demand and supply), they did not fully analyse the impact on energy costs to those residents and businesses.

As illustrated above, **natural gas peak capacity is 3 times the size of the electricity infrastructure (80,000 MW vs. 25,000 MW)**, as necessitated by winter peak requirements. Electrification of natural gas load of this scope and scale has never been contemplated in any jurisdiction, and the long term impacts to the Ontario economy need to be fully understood and carefully evaluated. Recently, Toronto Hydro estimated that converting natural gas heating for that city alone to electricity would require seven new nuclear reactors.[6]

In simple terms, to accomplish electrification of the entire province would require a three-fold increase in Ontario's generation, transmission, and distribution assets. ICF has estimated that this would require an investment in **the order of magnitude of $500 billion**. An increase in electricity system investment of this magnitude would have significant, unsustainable impacts on annual and per unit electricity costs. It would result in the **per unit cost of electricity nearly doubling from the existing per unit cost of $142.5/MWh to $250 MWh.**

1. INNOVATION

As outlined in the LTEP Discussion Guide, the pace of change in the energy sector is high; and much of that is related to the advances in energy technologies. Ontario needs to take advantage of these new opportunities in

[6] "...the scale of the transformation is staggering. To stop using natural gas for heating in Toronto would mean building seven new nuclear reactors or installing a solar panel that would cover about two-thirds of the city of Toronto." A. Haines, quoted in The Globe and Mail "Toronto Hydro will face billions in expenses if it wants to keep up" by Marcus Gee (September 27, 2016).

order to achieve a diversified energy portfolio which provides price certainty and reliable supply, while balancing the need for reduced greenhouse gas emissions as outlined in the Climate Change Action Plan (CCAP). Innovation in the energy sector not only creates new energy technology but also new jobs and associated economic growth.

Ontario should recognize the value of the 'ready to implement' solutions already available while committing to fostering energy innovation and the associated partnerships to advance new technologies and solutions. Union Gas is proud to have started to work with several Ministries and industry associations on some of these initiatives and looks forward to collaborating with government on new opportunities in the future.

Natural Gas for Transportation

The transportation sector is one of the largest contributors to Ontario's GHG emissions, accounting for 60.2 Mt or 35% of the province's emissions in 2014[7]. Heavy duty diesel vehicles are responsible for more than 20% of these emissions, emitting 13.1 Mt of CO2e annually or roughly 8% of Ontario's total emissions[8]. Natural gas in its compressed form (CNG) or in its liquefied form (LNG) is cleaner (17% emission reduction) and lower cost (cost reduction up to 50%) alternative than diesel.

Natural gas engine technology for medium and heavy duty trucks is readily available and proven to significantly reduce tailpipe emissions. Each year, Ontario consumes 5,865 million litres of diesel and 15,764 litres of gasoline for transportation.[9] CNG and LNG technology could ultimately displace much of Ontario's use of diesel and gasoline, in the medium and heavy duty markets, and heavy fuel marine applications.[10] This could provide a GHG reduction of 2.5Mt CO2e/year by 2030 (assuming a 17% 'wells to wheels' GHG reduction for spark ignited engines vs. diesel). This could also provide a potential economic development opportunity in engine manufacturing.

However, there is a technology and infrastructure stalemate in Ontario today. Truck fleet owners cannot commit to a new lower carbon market fueled by natural gas engines without the supporting infrastructure to conveniently refuel their vehicles. Natural gas fueling and infrastructure companies cannot invest in building refueling stations without having a market to utilize them. There is an urgent and critical role for the Ontario government to provide early market grants to support the co-development of CNG refueling infrastructure in parallel with CNG truck engines. Recognizing that NRCan is in the process of providing funding for CNG station infrastructure, and Union Gas has tentatively been awarded funding, there needs to be coordination between the various levels of government to ensure sufficient funding exists to offset the early market risks of being first. This is a perfect leadership role for the Ontario government to take on.

The LTEP needs to address the technology and infrastructure stalemate for Compressed Natural Gas (CNG) that currently exists in Ontario by deploying both the engine conversion incentives and funding for CNG refueling stations as identified in the CCAP in Q1 2017. Alignment between federal and provincial funding would further enhance this market development and optimize all sources of funding

Renewable Natural Gas (RNG)

As recognized in the CCAP, Renewable Natural Gas (RNG) utilizes methane that is naturally emitted from landfills, waste water treatment

[7] 2016 National Inventory Report, Environment Canada
[8] ibid
[9] Report on Energy Supply and Demand in Canada – 2014 Preliminary – Table 3-8 - http://www5.statcan.gc.ca/olc-cel/olc.action?objId=57-003-X&objType=2&lang=en&limit=0
[10] Ontario 2014 diesel- http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/trade37b-eng.htm

plants, agricultural and industrial operations, which can be cleaned, compressed and added to the natural gas pipeline system. RNG represents a 'greener' supply source of carbon neutral natural gas to displace conventional natural gas utilizing existing infrastructure throughout the province. Renewable natural gas offers a sustainable source of greenhouse emission reductions and does so at an abatement cost that is significantly less than other options.

Union Gas supports the development and introduction of RNG into the natural gas system supply in Ontario and is committed to achieving a 2% of system supply target by 2020. Approximately 1/3 (~51 PJs/year) of the province's potential biogas (to create RNG) can be derived from organic waste, but another 2/3 (~113 PJs/year) of Ontario's potential supply will need to be created from biomass sources such as agricultural and forestry residue. Development of the province's biogas sources to produce RNG will take time and government funding commitments.

The current barrier to gas distribution utilities is that procurement of RNG is not currently approved by the Ontario Energy Board(OEB). Direction should be provided to the OEB in order to remove this barrier.

The province needs to provide direction to the Ontario Energy Board (OEB) in early 2017 requiring RNG to be included in the supply portfolio of natural gas utilities. A regulatory proceeding through the OEB will need to be completed in a streamlined fashion to revise the natural gas supply framework and initiate market development.

The funds identified in the CCAP towards RNG should recognize the balance between developing sources of RNG to meet the targets outlined above with maintaining affordability for end use consumers as RNG becomes a greater portion of the natural gas supply portfolio.

- **50% of the funding identified in the CCAP should be directed toward funding capital for the development of RNG sources (such as anaerobic digesters).**
- **50% of the funding should be used to offset the rate impacts to natural gas consumers resulting from blending RNG into the natural gas supply.**

Offset protocols developed as part of the Cap and Trade Program in Ontario can also help support the development of RNG in the Ontario marketplace by reflecting the capture of methane that would otherwise be released into the environment in order to drive emissions reductions in this sector in addition to the benefit RNG provides by displacing conventional natural gas.

Combined Heat and Power (CHP)

Ontario has traditionally relied on centrally located power generation assets to meet the peak energy demands in the province. However, new electricity infrastructure is expensive to build, especially in urban centres and these assets do not provide the dispatching flexibility required in the province, as we integrate more renewable power generation into the supply mix. Greater use of decentralized CHP applications diversifies the power sources and flexibility of the power grid and can utilize existing natural gas infrastructure as a fuel source without the need to build expensive electric assets. In recent years, industry, hospitals and agricultural businesses have invested in CHP to save cost and increase the energy reliability of their operations. Low natural gas prices, combined with increasing electric prices in Ontario, have improved the attractiveness of CHP for end users to effectively manage energy costs and provide reliable supplemental power. New CHP technology is now available that increases the opportunities for CHP utilization to smaller electric consumers.

If Ontario is to remain competitive with other regions in Canada and surrounding American States, managing energy prices must be of paramount focus for the province and CHP should be viewed as a viable option to achieve this goal. In the 2016 speech from the Throne, the government announced the lowering of the Industrial Commercial Initiative (ICI) threshold to help large electricity consumers reduce their bills. Government investment in CHP would enable Ontario Industry to realize more savings from the ICI and reduce pressures on the electricity system.

CHP should to be recognized as part of the energy portfolio in Ontario moving forward and take advantage of the economic and environmental benefits of doing so. IESO approved CDM programs rely on CHP as an important and affordable option to meet of electric conservation targets.

Existing CHP program support such as Process System Upgrade Initiative (PSUI) funding provided by IESO to support capital investments in CHP should continue. As well, the province must ensure that free allowances for CHP are extended past 2020 so that no financial burden is placed on existing CHP users, and expand allowances to include emitters of less than 10,000 tonnes/year.

The 'Integrated Option' for Homes

Union Gas recognizes that constant improvement in home energy effiency is a goal of both the provincial and federal governments. While signicant improvements can and must be made, regulators must take into consideration technological realities, affordability and consumer choice. If government continues to move in this direction, an 'integrated option' is the best model.

The integrated option is one which optimizes the use of existing electricity infrastructure to continue to serve the summer peak demand and shoulder winter months, and existing natural gas infrastructure to continue to serve the winter peak demand. The integrated option would:

- Use an air-source or ground-source heat pump to serve space heating and water heating load in summer and winter shoulder months, as well as warm winter days.
- Use high-efficiency natural gas to meet demand on the coldest winter days (colder than -5C to -8C).
- Recognize that air-source heat pumps are highly efficient in moderate and warm temperatures, but inefficient in colder temperatures. In this case, natural gas is more efficient and affordable.

This alternative optimizes the capacity and unique strengths of the natural gas and electricity transmission/generation systems and equipment. A recent ICF study found that the integrated option would not require additional electrical generation or transmission capacity to be constructed to serve the winter peak, which translates to a much more cost effective solution for Ontario to reduce greenhouse gas emissions. Ontario electric consumers spent $20.5 billion/year on electricity costs in 2015. Electrifying just 25% of the natural gas customers to electric heat and hot water would cost an incremental $19 billion/year. However, the integrated option would only cost $7.9 billion

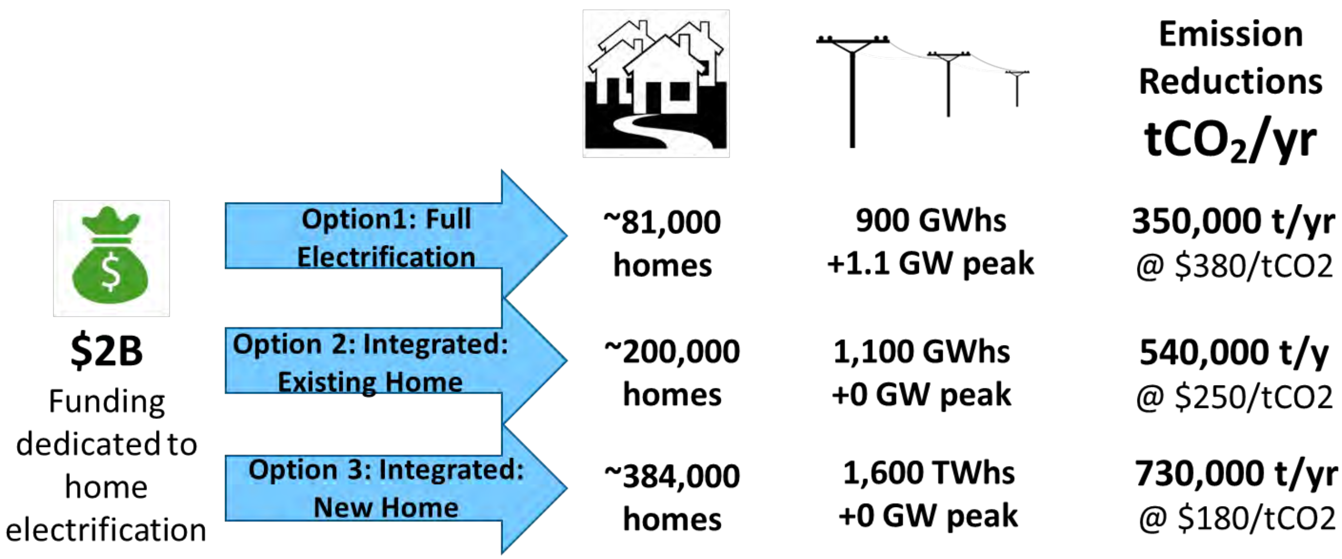
The ICF study also found that the integrated option is effective in reducing GHG emissions by 60%. If applied to 25% of single family homes by 2035 (consistent with Outlook 'D'

[11] IESO "Outlook D" assumes '50% of gas market share', meaning equipment related decisions. This equates to approximately 800,000 homes (approximately 25% of the current homes in Ontario) converted by 2035.

IESO OPO[11]), it would reduce GHG emissions by 2 MT C02e/year, and 30 MT C02e over 15 years. This translates to an abatement cost of $250/tonne C02e.

The following chart illustrates the relative impact an allocation of $2 billion of CCAP dollars would yield. The key conclusion is that all options regarding home electrification are expensive; however the integrated solution for new homes is the least costly. It would deliver more than twice the GHG reductions (730,000 tonnes/year) for the same investment as fully electrifying existing homes. This equates to an abatement cost of $180/tonne.

Figure 2: ICF Electrification Study November 2016

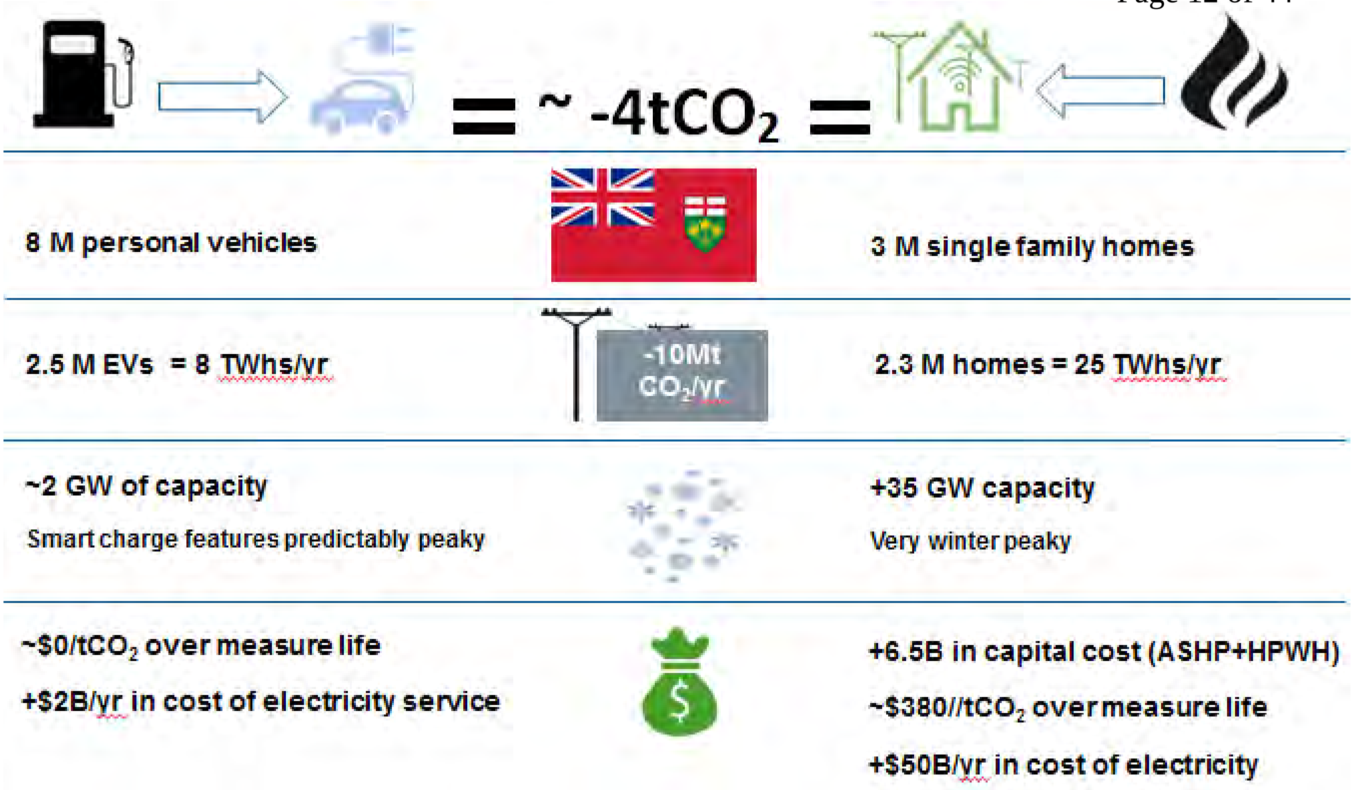


Electrification of Personal Vehicles

The chart below summarizes a recent ICF analysis comparing the electrification of personal vehicles versus the electrification of single family homes; both of which achieve the equivalent emissions reductions.

- An average home and an average car in Ontario both produce approximately 4 t/CO2 per year.
- There are approx. 8 million cars in Ontario and approx. 3 million single family homes in Ontario.
- To reduce emissions by 10 Mt, you would have to electrify 2.5 M cars or 2.3 M houses.
- $2 billion / year in cost of electricity service for vehicles vs. $50 billion / year in cost of electricity service for homes can control most recharging of vehicles to avoid impact on peak, vs homes that are unpredictably peaky based on winter weather.
- $0/t of C02 in cost abatement over the measured life for vehicles vs. $380/t C02 over measured life for homes.

Figure 3: ICF Electrification Study November 2016



The electrification of personal vehicles would provide a much more viable option than the electrification of homes (outlined in the OPO and FTR) to achieve the same carbon reductions of 4t C02 per vehicle or home.

Additional Solutions

Below are additional technological advances that are commercially available or nearly commercial that will support the province's long term energy goals. Each of these would optimize the existing energy infrastructure in Ontario today, providing cost effective alternatives to reduce GHGs.

- Decentralized distribution in the form of micro Combined Heat and Power (mCHP) units for residential homes can provide heat and electricity to a home in a very efficient manner whereby almost all of the energy in fuel is utilized. This is in contrast to conventional gas power plants where a substantial amount of heat is lost to the environment at the generation site and further electricity 'line losses' occur along transmission and distribution lines as electricity is moved from a central source to an end user. Recent technological advancements have resulted in smaller CHP units producing 5-100 Kilowatts being readily available and utilized in the market.
- Carbon capture is a critical technology for the industrial facility and may evolve further into the development of commercial and residential scale applications. Some Ontario industries are already capturing and utilizing

their CO_2 emissions. For example, in the Ontario greenhouse sector some operations capture their carbon dioxide emissions from natural gas fired boilers (used for heating) and direct this source of CO_2 into their greenhouses to enhance plant growth.

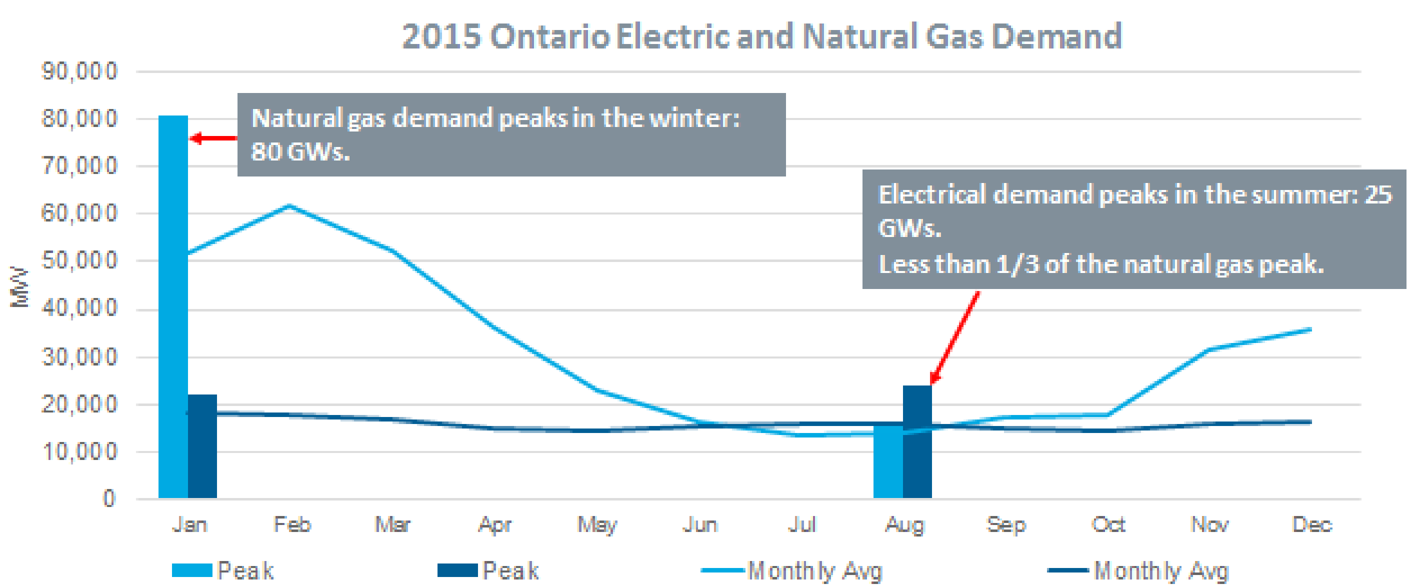
- Electricity storage technologies are currently being developed at various scales and time spans to balance electrical grids needs, as evidenced by the IESO's recent procurement of 50MW of electric storage. Stored electricity can be converted into non-emitting hydrogen via an electrolzyer, a concept referred to as Power to Gas (PtG) and then stored and distributed using existing natural gas infrastructure, ultimately optimizing the existing energy assets in the province.

2. Energy Supply & Delivery

Diversified Energy Supply

A recent ICF study compared the monthly average energy and the peak capacity energy for both natural gas and electricity in 2015:

Figure 4: ICF Electrification Study November 2016



There are three important conclusions to draw from this graph:

1. Existing natural gas and electricity infrastructure work in concert to serve Ontario's energy requirements.

- Natural gas serves the winter peak.
- Electricity serves the summer peak.

2. The natural gas infrastructure has peak capacity[12] that is more than 3 times the size of the existing electricity infrastructure.

- Natural gas peak capacity is 80 GW.
- Electricity peak capacity is 25 GW.

[12] In order to serve peak capacity, a greater level of installed capacity is required. For example, 80 GW of peak capacity requires approximately 100 GW of installed capacity, and 25 GW of peak capacity requires approximately 35 GW of installed. The IESO 2016 Ontario Reserve Margin requirements Report that indicates a required reserve ranging from 17% to 27% between 2016 and 2020.

3. The loads served by natural gas are more "peaky" than electricity.

- Electricity loads in 2015 varied between 15 GW and 20 GW.
- Natural gas loads in 2015 exceeded 60 GW(February – not a single peak day), compared to 15 GW (July and August).

The same study found that in addition to providing more than 3 times the infrastructure to serve peak load, natural gas serves more than double the annual energy consumption. In 2015, the natural gas system provided 270 TWh (approximately 1000 PJs) of energy to Ontario homes and business; the electricity system provided almost 143 TWh (~525 PJs) in the same timeframe.

The LTEP should acknowledge the dominant role that natural gas plays to provide affordable energy in Ontario and support the value of a diversified energy portfolio and leverage existing energy infrastructure to meet the province's energy demands and emissions targets.

The LTEP should acknowledge the dominant role that natural gas plays to provide affordable energy in Ontario and support the value of a diversified energy portfolio and leverage existing energy infrastructure to meet the province's energy demands and emissions targets.

Community Expansion

As recognized in the 2013 LTEP, the quality of life and economic prosperity of Ontario depends on access to natural gas and natural gas infrastructure. Expanding natural gas access to more rural areas and remote communities in Ontario is crucial to stimulating the economy in those areas, ensuring existing businesses remain competitive, and attracting new business. The province has committed to work with natural gas distributors and municipalities towards this goal, and committed funding ($200M Natural Gas Access Loan and $30M Natural Gas Development Grant) as part of the most recent budget.

In conjunction with the recent decision by the Ontario Energy Board outlining a new framework for the expansion of natural gas in Ontario, the province should unlock access to the committed funds in order to facilitate expansion to rural areas and remote communities. In order to maximize the expansion capability within rural Ontario, the 2017 LTEP should designate additional funding to the expansion of natural gas to remote areas of the province to provide affordable energy to these areas and replace higher emission alternatives.

3. Conservation / Efficiency

Union Gas has been designing and delivering Demand Side Management (DSM) programs in Ontario since 1997; in fact between 1997 and 2014, these programs have helped reduce emissions by 16 MtCo2e.

Union Gas' 2015-2020 DSM Plan expects to achieve more than 15 billion cubic meters of lifetime natural gas savings which equates to approximately 29 MtCo2e in emissions reductions over the life of the equipment.

Starting in 2016, Union Gas (and Enbridge Gas Distribution) will be working in partnership with the Ontario government as part of the $100 M Green Investment Fund to deliver an enhanced

Home Renovation conservation program to non-gas customers. With funding from the Green Investment Fund, Union Gas will be able to help an additional 12,000 homes patriciate in the Home Renovation Program, resulting in an extra 600,000 MtCO2e in emission reductions over the life of the new equipment.

The LTEP should recognize the value of energy conservation to achieve emission reductions and promote the continuation and expansion of utility led DSM programs as a separate means to augment the Green Bank Investment fund. Leveraging DSM programs delivered by Union Gas with our established market experience, relationships, and processes, will deliver additional conservation savings and emission reductions outside of the Green Investment Fund.

4. Energy Prices

Energy prices and price certainty related to future energy prices are key economic drivers for both consumers and businesses. Natural gas continues to be the most affordable source of energy in the province of Ontario and is expected to maintain a cost advantage over fuels into the foreseeable future.

Union Gas believes it is important the financial impacts of Cap and Trade and the CCAP, to the home and business in Ontario be reflected in Ontario's Long Term Energy Plan, to provide transparency and encourage the behavioural changes required. It is particularly important to look at the stacking effect on prices of multiple initiatives such as those outlined in the CCAP, as well as the procurement of carbon allowances to ensure the cost advantage on natural gas is not eroded going forward.

The CCAP has allocated more than $2 billion to pursue low-carbon technologies such as geothermal and air-source heat pumps as an alternative to fossil fuels such as natural gas. Union Gas recognizes that in a low-carbon economy, multiple technologies and energy solutions need to be employed. However, large scale electrification of homes, businesses and industry will have significant impacts for the province from an economic and consumer affordability perspective.

Energy prices and certainty are key economic drivers. Consideration of these costs and capacity impacts of the CCAP should be outlined in the LTEP to ensure they are understood by stakeholders and managed accordingly.

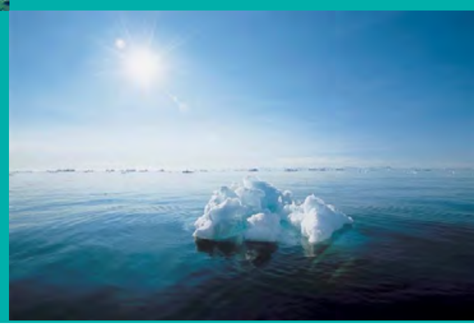
Summary

1. Union Gas supports the province's goals of moving towards a lower emissions environment, and believes it should be approached in a manner that balances environment, the economy, and affordable energy.
2. Energy prices and certainty are key economic drivers. Consideration of the cost and capacity impacts to electrify the province's energy requirements as described in the CCAP should be outlined in the LTEP to ensure they are understood by stakeholders and managed accordingly.
3. If the Ontario government chooses to convert homes from natural gas to electric heat (and require new homes to be electric rather than affordable natural gas), Union has offered an integrated solution that obtains 60% of the carbon reduction at significant savings.
4. The 2017 LTEP should designate additional funding to the expansion of natural gas to remote areas of the province to provide affordable energy to these areas and replace higher emission alternatives.
5. The LTEP should address the technology and infrastructure stalemate for Compressed Natural Gas (CNG) that currently exists in Ontario by deploying both the engine conversion incentives and funding for CNG refueling stations as identified in the CCAP in Q1 2017. Alignment between federal and provincial funding would further enhance this market development and optimize all sources of funding.
6. In early 2017, the province should provide direction to the Ontario Energy Board (OEB), requiring Renewable Natural Gas (RNG) to be included in the supply portfolio of natural gas utilities. A regulatory proceeding through the OEB will need to be completed in a streamlined fashion to revise the natural gas supply framework and initiate market development.
7. Combined Heat and Power (CHP) should be recognized as part of the energy portfolio in Ontario moving forward and take advantage of the economic and environmental benefits of doing so. The IESO approved CDM programs rely on CHP as an important and affordable option to meet electric conservation targets.

Union Gas looks forward to continuing to work in partnership with the Ontario government on achieving the goals outlined in the upcoming Long Term Energy Plan. We believe natural gas is an integral part of the energy portfolio and a key component to finding a balance between the environment, the economy, and affordable energy.

Thank you for your consideration of our submission.

A Spectra Energy Company



Electrification and Ontario's Long Term Energy Plan

December 1, 2016

Prepared for:
ENBRIDGE GAS DISTRIBUTION AND UNION GAS

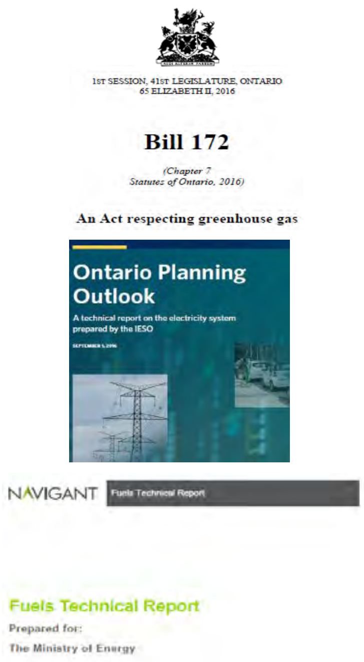
Duncan Rotherham

Key Messages

- The electricity and natural gas systems currently work in a complementary fashion to meet total annual demand (~400TWhs) for energy as well as winter (natural gas 80GW) and summer (electricity 25GW) peak demand.
- Natural gas supplies twice the annual energy of electricity at 20% the cost per unit of energy.
- Electrification measures aimed at natural gas will be challenged by cost effectiveness and the capacity constraints of the existing electrical system. Significant investment in electricity generation, transmission, and distribution required to meet any new winter peak capacity requirement.
- Home heating related measures (e.g. heat pumps) that rely on electricity to operate must be balanced with affordable and reliable natural gas to protect consumers, maximize consumer choice and ensure a reliable, affordable and sustainable energy system.
- An integrated option heats the home with electricity and natural gas without impacting the winter peak day electric demands in Ontario. It would reduce emissions by 60%, minimize the need for additional electric infrastructure (generation, transmission, distribution, in-home) and cost less that half of the full home electrification.
- By focusing on the electrification of vehicles the province can reduce GHG emissions and create value with existing non-emitting generation domestically at little or no cost.

Ontario's Energy and Climate policy must come into synchronicity in the Long Term Energy Plan.

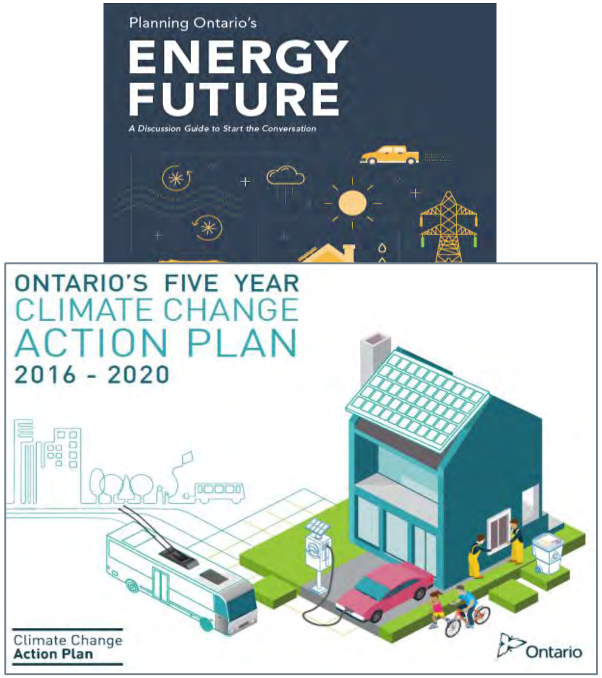
Optimizing existing energy infrastructure and existing / evolving technology will be critical to meeting Ontario's decarbonisation goals in a cost effective manner while ensuring a reliable, affordable and sustainable energy system.



Climate Change Mitigation and Low-carbon Economy Act, 2016

IESO Ontario Planning Outlook (Sept 2016)

MoE Fuels Technical Report (Sept 2016)



As an input to Ontario's Long Term Energy Plan (LTEP) the following considers the viability of opportunities to leverage electrification measures identified in Ontario's Climate Change Action Plan (CCAP) and modeled in the IESO's Ontario Planning Outlook (OPO) electrification scenarios.

Contents

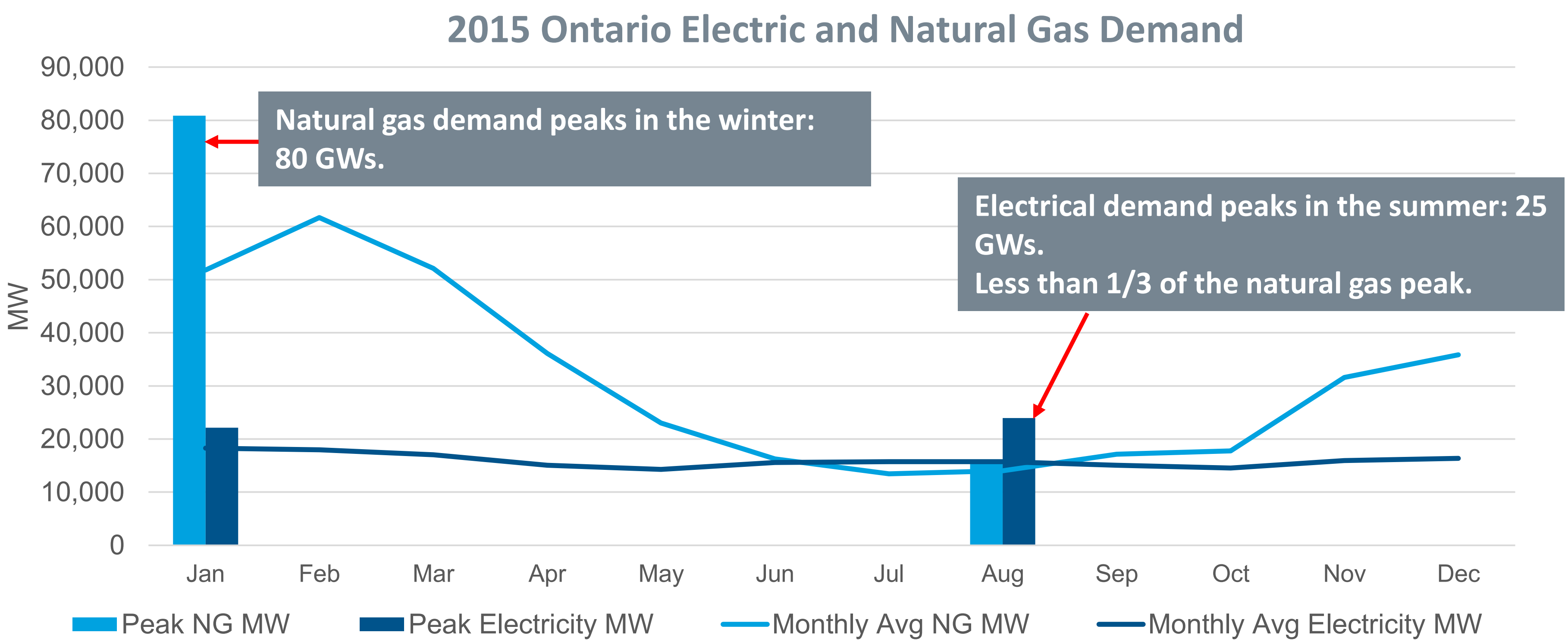
A) Understanding Ontario's energy systems: Electricity and Natural Gas

- Natural gas meets almost twice the annual energy demand as electricity and over three times the peak day demand.
- The natural gas system provides this energy for 20% the cost on a per unit of energy basis vs. electricity.

  - The natural gas system has a book value of $16.3B. In 2015 it deployed 270 TWhs of energy at cost of $7.7B or $30/MWh.
  - The electricity system has a book value of >$70B. In 2015 it deployed 142.5 TWhs of energy at cost of $20.5B or $142.5/MWh.

Recognizing the role / importance of natural gas in Ontario.

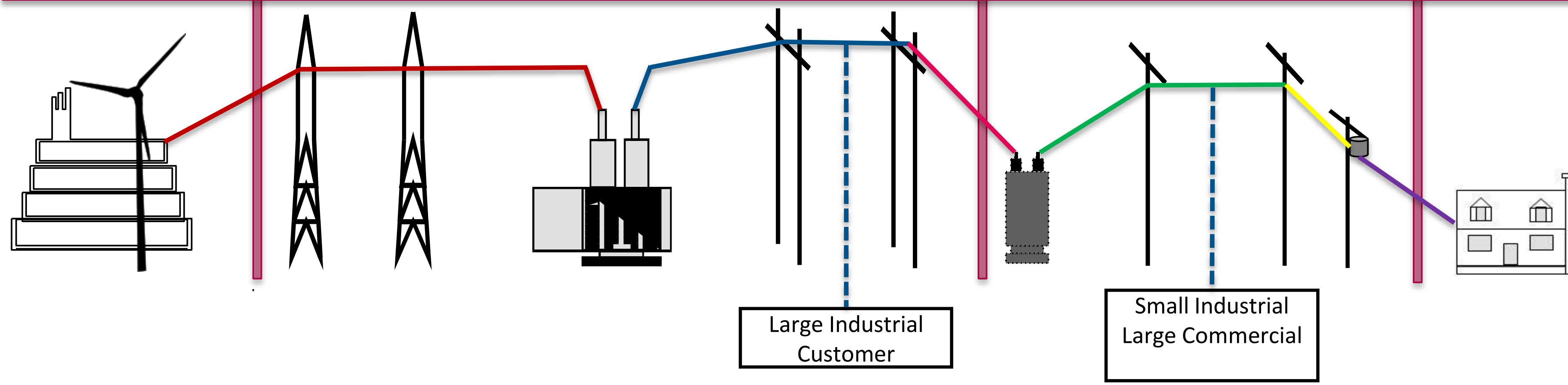
Natural gas meets over 80% of winter peak day demand and more than twice the annual energy demand of electricity.



On an annual basis the natural gas system provides 270 TWh (~1,000 PJs) to customers in Ontario while the Ontario electricity system provides 142.5 TWh (~525 PJs) in net energy.

Ontario's electrical system infrastructure book value – $70-75B.

Generation	Transmission			Distribution			Services
Generating Stations	**115-500kV Main Grid Lines**	**230-500/115-230 kV Substations**	**115-230kV Radial Lines**	**115-230/27.6-44 kV Subs**	**27.6-44kV Radial Lines**	**13.8kV Radial Lines**	**Meter Reads, Billing, etc.**

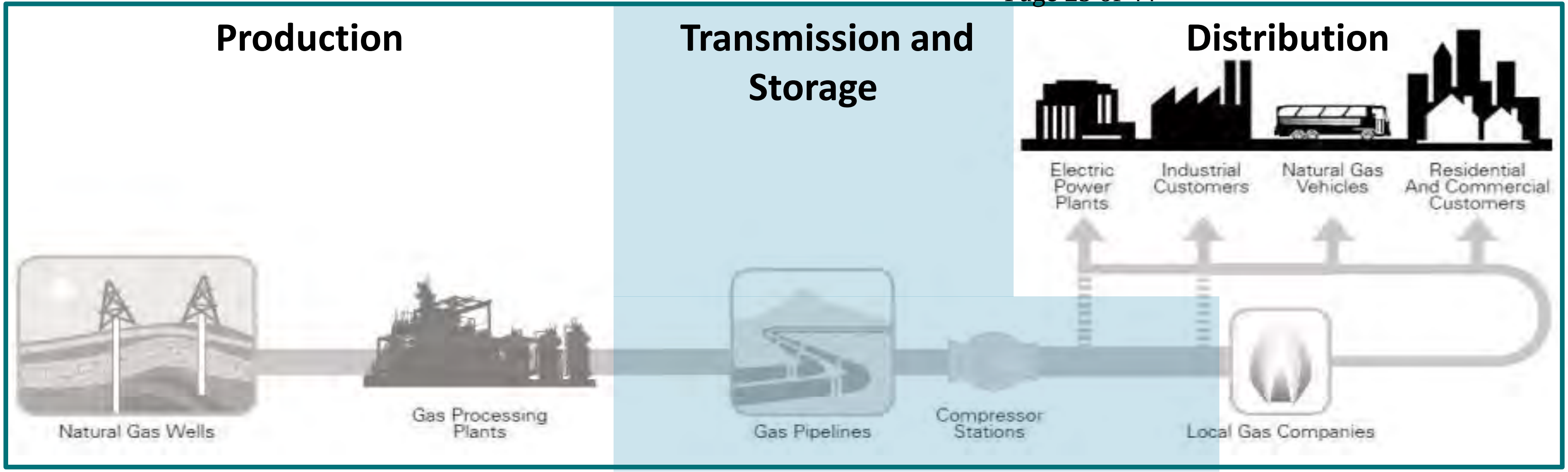


Generation	Transmission	Distribution	Services
38 GW	30,000 km	20,000 km	5M customers
$40 – $45B	$12.5B	$18B	

$70 – 75B

In 2015 the total cost of electricity service was $20.5B/yr with an average unit cost of $142.5/MWh.

Ontario's natural gas system infrastructure book value = $16.3B



Source: Natural Gas Council

Production upstream of Ontario*

13,000 Km
78 compressor stations
80+ TWh energy storage

102,000 km

3.6M customers

$16.3B

In 2015 the total cost of natural gas provided was ~$7.7B/year with an average unit cost of $30/MWh across all residential, commercial and industrial customer classes.

* Costs of gas production and transmission and commodity price have been included in cost analysis

B) Electrification of the winter peak: Challenges and Costs

- Electrification of the winter peak natural gas load will be more significant and costly than initial high level estimate provided by the IESO
- IESO top-down analysis in the Ontario Planning Outlook underestimates peak capacity required to meet greater electrification of the economy and cost.
- Due to day to day and seasonality driven “peakiness” the added winter peaking capacity, while costly and critical for reliability, will rarely be called on.
- Due to the underestimation of the peak capacity requirement the IESO analysis also underestimates the $/MWh impact.
- Due to the above, and the cost of natural gas vs. electricity, electrification measures that impact winter peak will be very costly.

ICF and IESO Reports - Both Provide Valuable Insights and are Complementary

A Difference in Approach

- IESO OPO report reviewed the impact on capacity for a target demand
- ICF built a bottom up analysis for a single home and applied it to all homes included in Outlook D

A Difference in Assumptions

- IESO report assumes normalized weather and considers coincident peak impacts; these peaks may not be coincident
- ICF report assumes peak demand requirements
- ICF report specifies air source heat pump for water and space heating

A Similar Conclusion

- Peak capacity will increase ~11 GW which has a significant capacity impact for Ontario and will be challenging from a cost and practical perspective

11.8 GW of peak capacity to meet demand from full electrification of ~25% of single family homes alone; Full economy impact of 80 GW compared to existing peak electric capacity of 25 GW.

1 home	~790,000 homes	All 3M homes	All NG load	
14.7 kW*	**11.8 GW**	44 GW	80 GW	Capacity at peak
	16 - 21 GW	60 - 75 GW	100 GW	Installed capacity to meet peak
	$10 - $12B/yr	$35 - $45B/yr	$65 - $80B/yr	Added annual cost of electricity service

14.7 kW* - assumes complete electrification of the home (heat and hot water) via ASHP and HPWH.

ICF and IESO analysis illustrate electrification impacts peak day; IESO initial analysis may be understated

	IESO Outlook "D"	ICF
Scope	Residential (single and multi-family), commercial, industrial, EVs, public transport.	Single family homes
Key Assumptions (2035)	Electric heat pump, space and water heat gain 50% of res/comm market;10% industrial; 2.4M EVs	25% homes converted by 2035 (790,000 homes)
Peak Impact	+11.3 GW	+11.8 GW
Added Generation	+49 TWh (vs Outlook B); +13 TWhs from residential alone; total 197 TWhs	+8.7 TWhs; total 157 TWhs
Added Annual Cost	+$8.5B/yr for added generation (excluding distribution) Total of $27.5B/yr for system	$10-$12B/yr for added generation (including distribution) Total of $30B/yr for system
$/MWh Cost	$170/MWh for added generation $137-142/MWh for system	$500-600/MWh for added generation $190/MWh for system

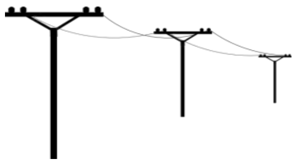
Illustrating the impact of added capacity and low load factor (~10%) resulting from the electrification of 25% of single family homes and 2.4M Evs on the cost of electricity ($/MWh)

~790,000 homes

+

2.4M EVs

+ 15-20 TWh/yr



16 - 21 GW capacity installed

$10 - $12B/yr in added cost of electricity service

Added annual demand

=

$500-600* / MWh

Per unit of added supply

vs.

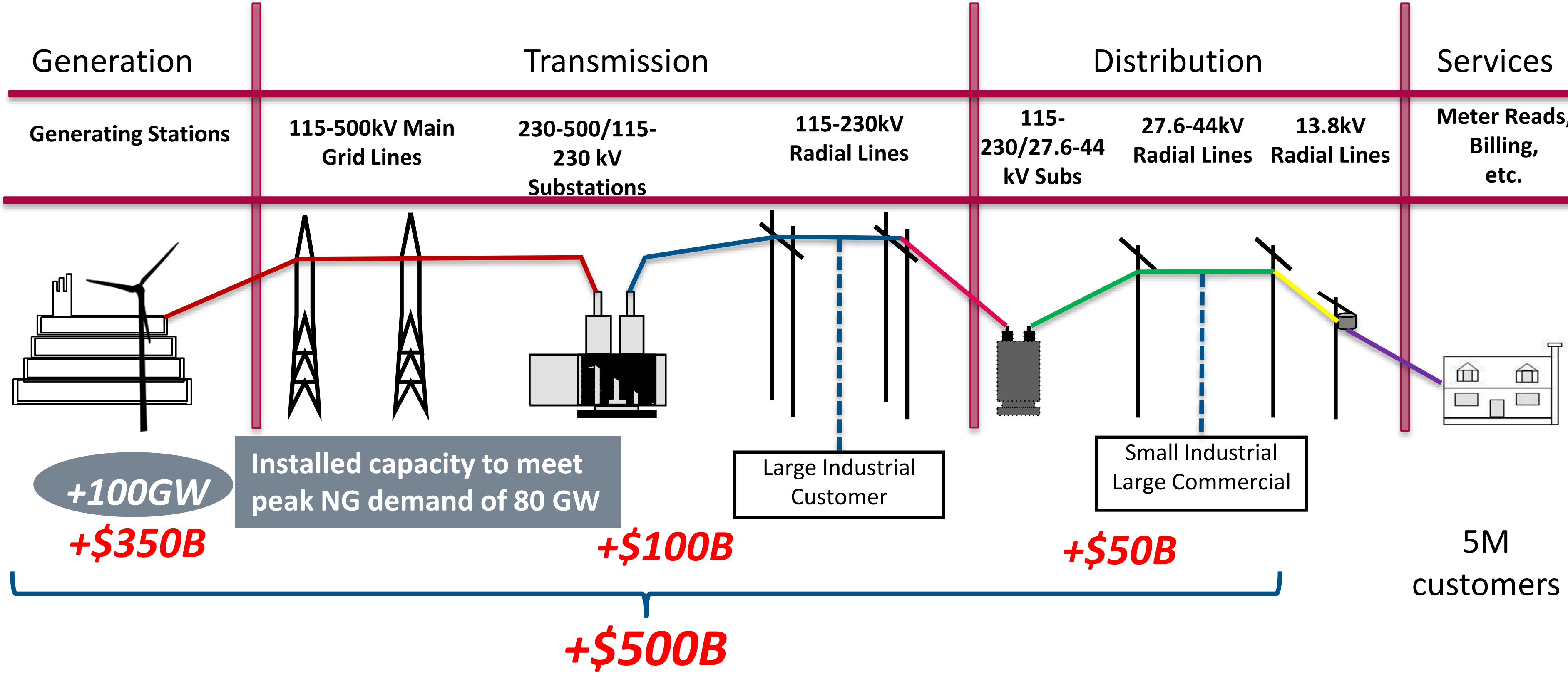
IESO's estimated $170/MWh for added supply

790,000 homes and 2.4M EVs compare with the single family home and transport components of the IESO's Outlook D. IESO's Outlook D demand expected to increase by 49 TWhs and system cost by $8.5B/yr = $170/MWh.

**If overnight EV charging is free, or <$140/MWh, the cost per unit of added supply could be as high as $1,250/MWh*

Illustrative depiction of Ontario's electric system infrastructure under a full electrification scenario. $500B in capital required.

No such energy system transition has been considered in a jurisdiction such as Ontario



The total cost of electricity service could be $100B/yr with an average unit cost of ~$250/MWh. Compare to 2015: $20.5B/year, average unit cost of $142.5/MWh.

Home Electrification: results for the single family existing home.

The cost (system and rate) of electricity vs. natural gas will make natural gas to electric measures very expensive. And well beyond the expected $18/tCO2 cap and trade price.

Electrification scenario:	Per Home	~25% of Homes
Capital Costs (delta vs NG)	$2,850	$2.25B
Annual Energy Costs (delta vs NG)	$1,000/yr	$0.8B/yr
Total = Capital + Energy Costs (15 yr)	$18,000	$14B
Annual Emissions from NG (tCO_2)	0 / yr	0
Annual Emission Reductions (tCO_2)	4.3 / yr	3.4 M / yr
Increase in Annual Electricity Consumption	11,000 kWh	8.7 TWh
Additional Winter Peak Demand	14.7 kW	**11.8 GW**
Cost of Emission Reduction (tCO_2)	$280 / tCO2	
Cost of upgrade to distribution system (15 yr)	**$6,500**	$5B
Total = Capital + Energy and Dist Costs (15 yr)	$24,500 ($1,600/yr)	$19B ($1.3B/yr)
Cost of Emission Reductions	**$380 / tCO2**	

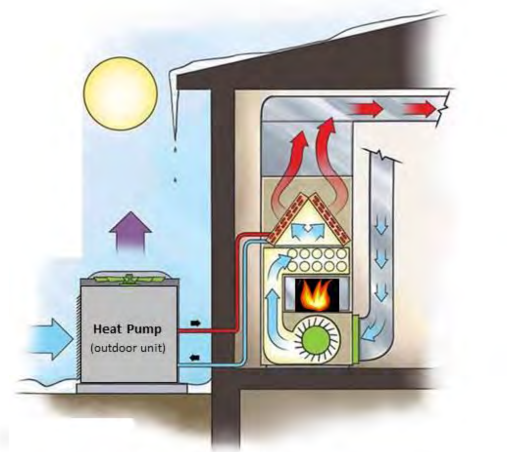
Assuming no need to upgrade the distribution system and no change in price per unit of electricity electrification of an existing home in Ontario would add $18,000 in cost over the 15 year lifetime of the electric technology vs natural gas and reduce emissions at $280/tCO2.

The distribution system would need to be tripled to meet 3X peak system cost would increase $432/yr per home or $6,500 over 15 yrs.
Cost per tonne of reduction would rise to $380/tCO2.

C) Utilizing Existing Electricity & Natural Gas Energy Infrastructure to Mitigate Cost of Decarbonisation

- An integrated option can reduce GHG emissions by 60% and optimize existing electricity & natural gas energy effectiveness vs. a full electrification measure.
- The full electrification solution can only yield reductions under the assumption that the electricity is non-emitting. This may become a challenge in the 2020-2035 timeframe with the loss of nuclear baseload capacity.
- Lower cost and higher effectiveness of the integrated solution allows for broader deployment throughout the economy and greater reductions.
- Targeting the new home can further decrease cost.

An Integrated Option: Utilizing Existing Electricity & Natural Gas Infrastructure to Mitigate Cost of Electrification



Source: www.familyhandyman.com

To minimize the need for incremental expensive winter peaking capacity and electric system transmission and distribution upgrades…

- Rather than the full-electric air source heat pump (ASHP) exclusively, leverage ASHP efficiency for spring, fall and most winter days and integrated natural gas fired technology for extreme cold periods.

This option would **reduce GHG emissions by ~60%** versus a home that currently heats with natural gas alone – if applied to **25% of single family homes** by 2035 this solution would reduce annual GHG emissions by **2 Mt CO2e/yr** and **30 Mt CO2e** over the 15yr measure life.

The integration option can be scaled to deliver more reductions at less cost

Electrification scenario:		ASHP + HPWH	Integrated ASHP + NG
# of Homes Converted to Electricity	Existing Homes	680,000	
	New Homes	110,000	
	Total	**790,000**	
Total Measure Spend		$19B	**$7.9B**
Annual Emission Reductions	Zero-Carbon Elec.	3.3 $MtCO_2e/yr$	2.0 $MtCO_2e/yr$
Increase in Annual Electricity Consumption		8,000 GWh	4,500 GWh
Additional Winter Peak Grid Demand		11,800 MW	0 MW
Cost of Emission Reductions		$380 / tCO_2	**$250 / tCO_2**

Full electrification of 790,000 homes in Ontario would add $19B in cost (vs a conventional NG solution).

An integrated electric – gas option would add $7.9B in cost and minimize requirement for costly added winter peaking electrical capacity to meet load.

- **The integrated option mitigates the cost per portfolio of 790,000 homes (~25% of Ontario) by ~$11B.**
- **Reductions per home are higher under a full electrification ONLY where all added electrical capacity is non-emitting.**

Targeting the new home can further reduce costs.

Ontario adds 25,000 new single family homes per year. Deploying an integrated electric-gas option can mitigate the cost of full electrification.

Electrification scenario:	Integrated ASHP + NG
Capital Costs (delta vs NG Base Case)	-$1,000
Annual Energy Costs (delta vs NG Base Case)	$410/yr
Total Measure Spend (= Capital Cost + Lifetime Energy Costs)	**$5,200**
Annual Emissions from NG	1.4 tCO2e/yr
Annual Emission Reductions	1.9 tCO2e/yr
Increase in Annual Electricity Consumption	4,100 kWh/yr
Additional Winter Peak Demand	0 kW
Lifetime Cost of Emission Reduction	**$180 / tCO2**

The integrated option for new homes is $5,200 in added cost per home.
Almost half the cost of an existing home.

Reductions per home are lower under the assumption the new home is more energy efficient however cost effectiveness is better.

$2B CCAP Funding: The integrated electric – gas option will impact more homes drive more reductions at less cost vs. full electrification

	Homes	Electricity	Emission Reductions tCO_2/yr
Option1: Full Electrification	~81,000 homes	900 GWhs +1.1 GW peak	350,000 t/yr @ $380/tCO2
Option 2: Integrated: Existing Home	~200,000 homes	1,100 GWhs +0 GW peak	540,000 t/y @ $250/tCO2
Option 3: Integrated: New Home	~384,000 homes	1,600 TWhs +0 GW peak	730,000 t/yr @ $180/tCO2

$2B Funding dedicated to home electrification

Cost effective deployment of the proceeds of sale of cap and trade allowance will be critical to meeting Ontario's target and minimizing reliance on exogenous compliance units that transfer wealth.

Electrification of the personal vehicle is much more viable an electrification measure than the home.

But with a goal of reducing emissions cost effectively the market should pick winners and losers not the government.

= ~ $-4tCO_2$ =

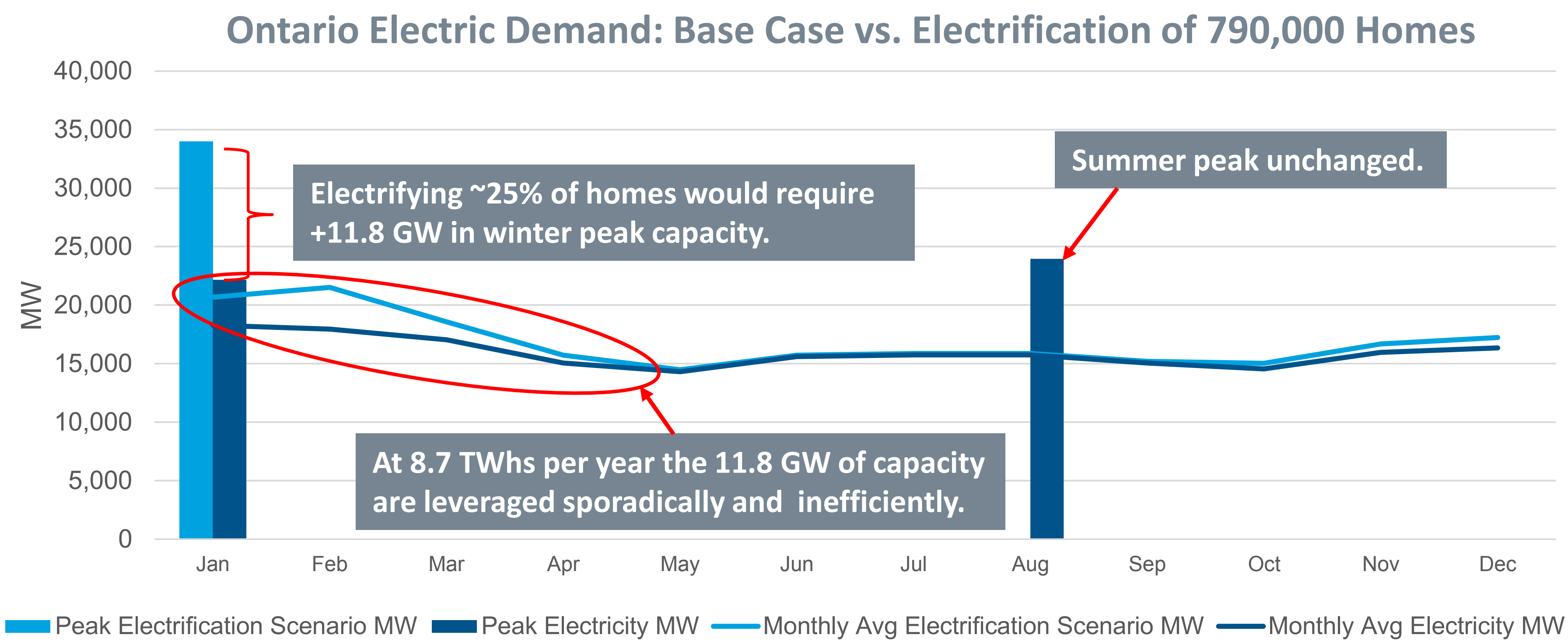
8 M personal vehicles		**3 M single family homes**
2.5 M EVs = 8 TWhs/yr	**-10Mt CO_2/yr**	**2.3 M homes = 25 TWhs/yr**
~2 GW of capacity **Smart charge features predictably peaky**		**+35 GW capacity** **Very winter peaky**
~$0/t$CO_2$ over measure life **+$2B/yr in cost of electricity service**		**+$6.5B in capital cost (ASHP+HPWH)** **~$380/t$CO_2$ over measure life** **+$50B/yr in cost of electricity service**

Recap: Key Messages

- The electricity and natural gas systems currently work in a complementary fashion to meet total annual demand (~400TWhs) for energy as well as winter (natural gas 80GW) and summer (electricity 25GW) peak demand.
- Natural gas supplies twice the annual energy of electricity and 20% the cost per unit of energy.
- Electrification measures aimed at natural gas will be challenged by cost effectiveness and the capacity constraints of the existing electrical system. Significant investment in electricity generation, transmission, and distribution required to meet any new winter peak capacity requirement.
- Home heating related measures (e.g. heat pumps) that rely on electricity to operate must be balanced with affordable and reliable natural gas to protect consumers, maximize consumer choice and ensure a reliable, affordable and sustainable energy system.
- By focusing on the electrification of vehicles the province can reduce GHG emissions and create value with existing non-emitting generation domestically at little or no cost.
- An integrated option allows gas and electricity to heat the home without impacting the winter peak day electric demands in Ontario. It would reduce emissions by 60%, minimize the need for additional electric infrastructure (generation, transmission, distribution, in-home) and cost less that half of the full home electrification.

Thank you

The addition of new winter peak electrical capacity is critical BUT it will only be leveraged annually at 8%



The IESO estimate of added capacity required to meet economy wide electrification targets under-estimates the challenge:

11 GW of peak winter capacity would be required to electrify 700,000 – or 20-25% of residential single family homes – not the IESO's economy-wide measures.

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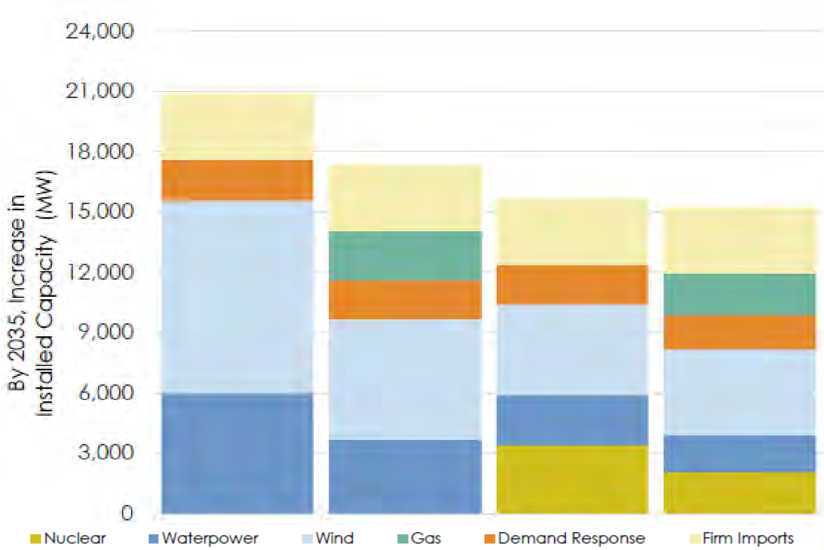
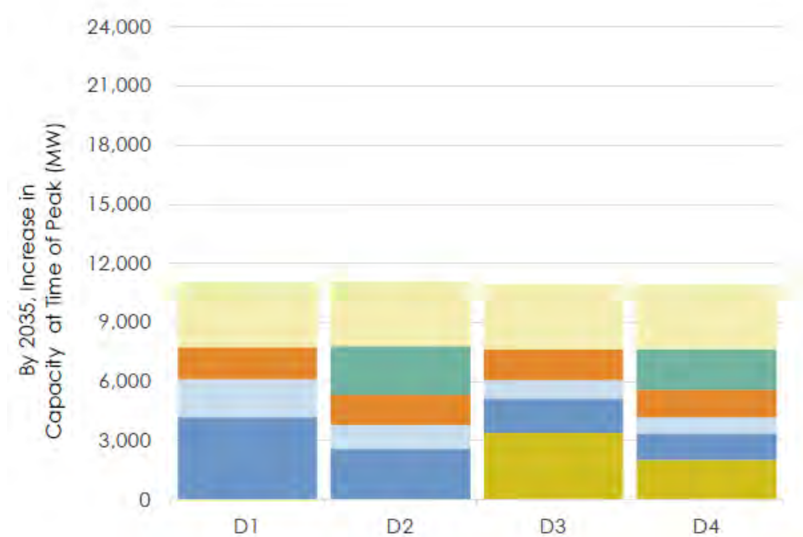




Electrical capacity requirements resulting from electrification (est. 16-21 GW) will require $Bs for generation, transmission and distribution systems

Ontario Planning Outlook: A technical report on the electricity system prepared by the IESO. September 1, 2016.

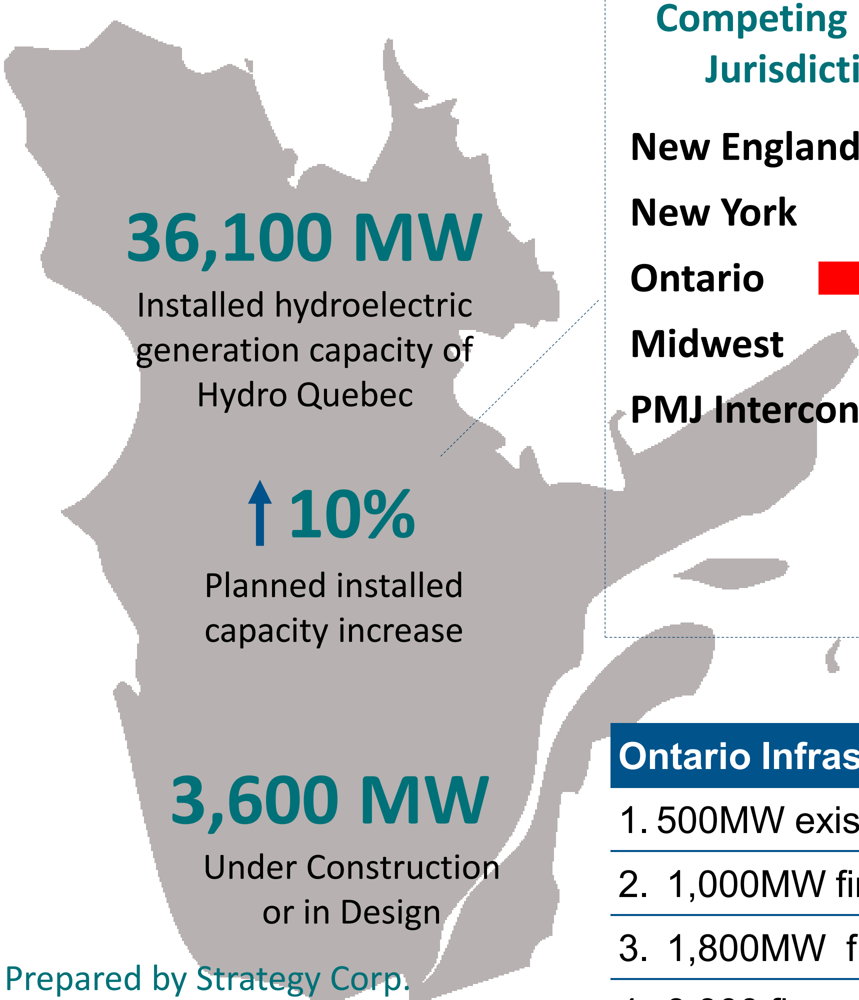
Winter peak capacity estimated to increase from 22 GW (2015) to 35 GW (2035) as a result of electrification measures.
The addition of 11 GW illustrated above would be adequate to meet the peak day demand from ~700K residential homes NOT the "economy".

IESO Assumptions Across Demand Outlooks

Sector	Outlook A	Outlook B	Outlook C	Outlook D
Residential (52 TWh in 2015)	48 TWh in 2035	51 TWh in 2035	Oil heating switches to heat pumps, electric space and water heating gain 25% of gas market share (58 TWh in 2035)*	Oil heating switches to heat pumps, electric space and water heating gain 50% of gas market share (64 TWh in 2035)
Commercial (51 TWh in 2015)	49 TWh in 2035	54 TWh in 2035	Oil heating switches to heat pumps, electric space and water heating gain 25% of gas market share (63 TWh in 2035)	Oil heating switches to heat pumps, electric space and water heating gain 50% of gas market share (69 TWh in 2035)
Industrial (35 TWh in 2015)	29 TWh in 2035	35 TWh in 2035	5% of 2012 fossil energy switches to electric equivalent (43 TWh in 2035)	10% of 2012 fossil energy switches to electric equivalent (51 TWh in 2035)
Electric Vehicles (<1 TWh in 2015)	2 TWh in 2035	3 TWh in 2035	2.4 million electric vehicles (EVs) by 2035 (8 TWh in 2035)	2.4 million EVs by 2035 (8 TWh in 2035)
Transit (<1 TWh in 2015)	1 TWh in 2035	1 TWh in 2035	Planned projects, 2017-2035 (1 TWh in 2035)	Planned projects, 2017-2035 (1 TWh in 2035)
Other**	5 TWh	5 TWh	5 TWh	5 TWh
Total* (143 TWh in 2015)**	**133 TWh in 2035**	**148 TWh in 2035**	**177 TWh in 2035**	**197 TWh in 2035**

Ontario Planning Outlook: A technical report on the electricity system prepared by the IESO. September 1, 2016.

Quebec is expanding its hydro capacity but it will not be enough to meet Ontario's needs on a regular basis



36,100 MW

Installed hydroelectric generation capacity of Hydro Quebec

↑ 10%

Planned installed capacity increase

3,600 MW

Under Construction or in Design

Competing Export Jurisdictions

New England

New York

Ontario

Midwest

PMJ Interconnection

- Quebec hydro cannot replace natural gas in Ontario because Quebec's supply is barely sufficient to meet its own internal demand
- Quebec is a winter peak jurisdiction with peak demand of 39,031MW and 38,743 MW in 2013-14 and 2014-15, respectively
- Ontario is becoming a dual peak jurisdiction with winter peak demand of 25,368 MW (2013-14) and 23,219 MW (2014-15) and summer peak demand of 23,297 MW (2013-2014) and 24,855 MW (2014-2015)
- Ontario also has severe infrastructure constraints in accepting firm imports from Quebec

Ontario Infrastructure Upgrade	Estimated Cost	Time
1. 500MW existing firm capacity		
2. 1,000MW firm capacity	$325M	3-5 years
3. 1,800MW firm capacity	$500M	5-7 years
4. 3,300 firm capacity	$1.4B	7-10 years

Prepared by Strategy Corp.

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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

Ontario Energy Board

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Ontario

By E-Mail and Web-posting

March 16, 2017

To: **All Regulated Natural Gas Distributors**
All Interested Parties

Re: **Framework for the Assessment of Distributor Gas Supply Plans**
OEB File No. EB-2017-0129

The Ontario Energy Board (OEB) is launching an initiative to develop a Framework for the Assessment of Distributor Gas Supply Plans ("Framework").

This initiative follows on from the Staff Report to the Ontario Energy Board (EB-2015-0238) regarding distributor gas supply plans that was issued in August 2016. The Staff Report recommended that the OEB's approach to the assessment of gas supply plans should include detailed reviews of the gas supply plans as well as specific timing proposals for the review of the plans. The OEB in its cover letter to the Staff Report indicated its endorsement of the recommendations of staff.

The objective of the Framework is to update the regulatory approach to the gas supply planning process and inject greater transparency, accountability and measurement into the current system to ensure that consumers are getting value for money. Implementation of the Framework will allow for a consistent approach to the assessment of distributors' gas supply plans.

The Framework will establish the OEB's expectations and objectives for distributors' gas supply plans and clearly articulate the approach the OEB will take to assessing whether the plans meet those objectives in order to ensure cost effectiveness and value to consumers.

Renewable Natural Gas

On December 16, 2016, the Minister of Energy issued a letter to the OEB encouraging "…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 portfolio." The

Framework developed will set out the OEB's expectations and approach to issues related to including RNG within the distributors' gas supply portfolios. It is expected that this aspect of the Framework will be guided by the OEB's findings in EB 2011-0242.

Scope

The Framework will establish the objectives upon which the OEB will base its assessment of distributors' gas supply plans, such as public policy, climate change including the inclusion of RNG in gas supply portfolios, adaptability/flexibility, reliability and consumer price/bill impacts. It will also set out the criteria, including metrics or targets, the OEB will apply in testing whether the plans meet the objectives, such as assessment of risk, environmental concerns, price predictability and continuous improvement by the distributors. In the Staff Report there were recommendations regarding the approval process and the Framework is expected to provide direction on this as well. To support implementation of the Framework the OEB will also develop Filing Guidelines ("Guidelines") that will identify the required information, timing and format of gas supply plan submissions by rate regulated gas distributors.

Next Steps

OEB staff intends to prepare an initial draft of the Framework document to be completed by fall 2017 for discussion with stakeholders. In preparing the draft OEB staff will establish a stakeholder working group to help inform OEB staff as it develops the draft Framework document. Specifics about the working group will be announced shortly.

It is anticipated that a final Framework will be completed by the end of 2017. More information on the process will be provided in due course.

Any questions relating to this letter should be directed to Jason Craig at Jason.craig@ontarioenergyboard.ca or at 416-440-8139. The OEB's toll-free number is 1-888-632-6273.

Yours truly,

Original Signed By

Brian Hewson
Vice President, Consumer Protection & Industry Performance

Cap and Trade Emission Reduction Program- Renewable Natural Gas

POTENTIAL BENEFITS:

- **Reduce emissions up to 8 MtCO2e by 2030 (through replacement of up to 16% of the Ontario conventional natural gas supply with Renewable Natural Gas by 2030).**
- **Encourage economic development of Ontario's bioenergy sector and 'Made-in-Ontario' greenhouse gas reduction solutions.**
- **Avoid the export of Ontario RNG resources to other marketplaces (e.g. California), and therefore emissions reductions, to other jurisdictions.**

REQUIRED ACTION:

- **Provide a policy directive to the Ontario Energy Board that a Renewable Natural Gas supply program needs to be established in 2016 to ensure supply is available at the start of 2017. The market mechanism to establish the RNG program would be as follows:**
  - **Based on a Renewable Portfolio Standard (RPS) approach, including an interim 2020 target volume of RNG to be purchased by the Ontario gas utilities (Enbridge and Union) in order to get the program underway.**
  - **The RPS process would require the gas utilities to source the RNG based on an RFP bid process to ensure market competitive terms (i.e., price, contract length, conditions of supply (e.g. firm, interruptible)) for the contracted RNG supply.**
  - **Review of the RNG purchase mechanism after an interim period (perhaps in 2020) when the program is established in order to meet the 2030 target of 8 $MtCO_2e$ of emissions reduction (by replacing 16% of total Ontario conventional supply by 2030).**
- **Offer funding as soon as possible from the Cap and Trade proceeds to invest in biomass gasification to RNG technology development (technology critical to meeting the 2030 target).**

Renewable Natural Gas (RNG), also known as "biomethane" is produced from biogas (produced by anaerobic digesters) and landfill gas (captured at landfill facilities) which contains approximately 60 percent methane and 40 percent carbon dioxide (CO_2). Methane is generated from the decomposition of organic material in an oxygen-free environment. This process is known as anaerobic digestion, and can be efficiently controlled within an anaerobic digester, or occurs naturally under landfill conditions. Examples of organic material include livestock manure, municipal wastewater and food waste. Therefore RNG is an innovative way to manage wastes from agricultural, industrial and residential activities. RNG is an example of a circular bio economy that captures value from converting wastes into useful and saleable "by-products", known as by-product synergy (BPS). Farmers and agricultural producers could benefit in this way by reducing their solid waste streams and receiving an additional revenue stream from RNG. Municipalities could likewise benefit from an additional revenue stream from their source separated organics (SSO) or landfill facilities.

To become RNG, the biogas and landfill gas must be cleaned to remove CO_2 and other impurities in order to meet pipeline quality standards, after which it can be fed into the local natural gas distribution network. RNG can also be produced from the conversion of biomass (wood waste and crop residue that cannot be easily anaerobically digested) through thermal-chemical processes, such as "gasification", that do not involve the combustion or burning of biomass to generate energy. Although the gasification process has been commercially viable for decades, the technological innovation required to create methane (RNG) from biomass is still developing and has not yet reached commercial maturity. Ontario has an opportunity to become a leading jurisdiction in commercializing this technology. Approximately two-thirds of the estimated RNG supplies are related to biomass conversion.

Barriers to a Made-in-Ontario RNG Industry

a) Immediate Barrier

There is no technology barrier for biogas and landfill gas RNG projects. However, as was the case with Renewable Electricity, the immediate barrier to Renewable Natural Gas is the lack of a price for Ontario RNG producers to recover the operating and capital costs associated with RNG systems. Markets for RNG have been established in competitive jurisdictions within the United States (particularly California) and potential producers are exploring these opportunities to develop Ontario RNG resources for export (and resulting carbon abatements) out of the province. In 2015, the largest RNG facility in Canada opened at a Progressive Waste Landfill in Quebec with their RNG production (and resulting abatement) being sold into California markets.

b) Long Term Barrier

While existing, commercial technology can upgrade biogas and landfill gas into RNG for injection in the natural gas system, there is a requirement for commercialization of technologies that can convert biomass into methane (RNG). Approximately two-thirds of the estimated RNG supplies in Ontario are related to biomass conversion and funding support for gasification technology is critical.

unionGas
A Spectra Energy Company

Made-in-Ontario Solution

To achieve emission reductions related to RNG, a viable RNG industry must be established in Ontario. The first step is to immediately create a RNG supply program. The following table forecasts potential supply in Union Gas's franchise, 2017 through 2030, which coincides with the Government's planned start for Cap & Trade (2017) and the emission reduction target year 2030.

Estimated RNG Volume, Union Gas franchise, cumulative, by year (million m^3/yr)

Year	2017	2018	2019	2020	2021	2022	2023
RNG Supply (M m^3/yr)	9	17	73	129	190	243	506
Year	2024	2025	2026	2027	2028	2029	2030
RNG Supply (M m^3/yr)	721	1,169	1,612	2,055	2,405	2,755	3,141

The year 2020 is the first Compliance Period for which Ontario will be a full WCI trading partner and the next mid-term emissions target. In order to move forward with an Ontario RNG industry, Union Gas proposes the government provide policy direction to the OEB to establish a Renewable Portfolio Standard (RPS). An immediate Ontario program is required in order to ensure carbon abatement opportunities are not shipped out of province. Union Gas recommends establishing a RPS with a target of 2% of Union's system gas supply to be RNG by 2020. The total potential RNG forecasted by 2020 is 129 million m^3, all of which comes from biogas or landfill gas, and represents just below 2% of Union Gas's system gas supply. This is an achievable target which enables an RNG industry to be established in Ontario, and allows time for further learning and program review, before embarking on a 2030 target.

Program Essentials:

- Renewable Portfolio Standard that targets a maximum 2% of Union's system supply by 2020
- Pricing and commercial framework allowing Union to competitively purchase RNG at prices required to support production and meet the 2% target
- Contract supply terms that allow Union to purchase RNG from Ontario producers on long term contracts (10 – 20 years)
- RNG purchased by Union will be incorporated into the utility's gas supply portfolio under a Board-approved process

Union also recommends that the government and the Board plan for a full RNG market review in 2020 with the goal of adjusting the program as required facilitating maximum GHG reduction by RNG through to 2030. Reviewing the program in 2020 will provide an opportunity for industry participants to discuss costs and rate impacts, ensuring that this new industry develops into an economic market segment that is self-sustaining.

In addition, the ability to achieve RNG targets post-2020 rests on the commercialization of technologies that can convert biomass into methane at an economic price. Technology funding for biomass conversion systems is required and significant funding can establish Ontario as an innovation leader for this necessary technology. Union Gas recommends a portion of Cap and Trade proceeds be allotted to support this technology commercialization.

By 2030, RNG can reduce emissions up to 8Mt CO2e by replacing 16% of the conventional natural gas supply.

Canadian Biogas Association

RNG and Climate Change

Ontario Government, March, 2016

RNG Supports Climate Change Policy

Key Messages

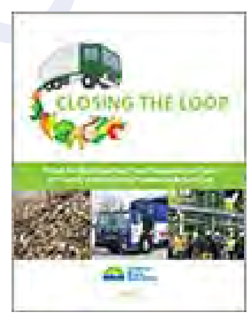
- 10% of our natural gas supply can come from renewable natural gas (RNG) by 2030. In the near term future, biogas can contribute approximately 3 percent of our natural gas needs, pending appropriate pricing, incentives and program rules.
    - In addition to cap & trade, Ontario needs a Renewable Portfolio Standard (RPS), whereby government and industry come together to set a target, process and date for compliance whereby utilities are obligated to have a percentage of RNG in the pipeline.
    - The Ontario government is in the process of setting up a government-industry RNG Working Group, which we strongly support.
    - The OEB should be directed to value GHG emissions in submissions by natural gas utilities.
- Currently, Canadian RNG – and associated carbon credits - is sold to California. We need timely policy to ensure Ontario projects help meet Ontario targets.
- Organic material diversion from landfill in Ontario needs to be a priority to help reduce the carbon footprint of the waste and agricultural sectors, and to ensure maximum conversion from waste to renewable energy. Organic diversion policies could be dovetailed with those of Quebec.

Background

Biogas has and continues to play an important role in helping Ontario provide cleaner air, water and enriched soils for our communities. Biogas should be considered as part of the immediate steps that Ontario takes to reach its greenhouse gas emission (GHG) reduction targets. The Canadian Biogas Association welcomes the opportunity to discuss how the development and use of biogas and renewable natural gas (RNG) can help Ontario meet its climate change target.

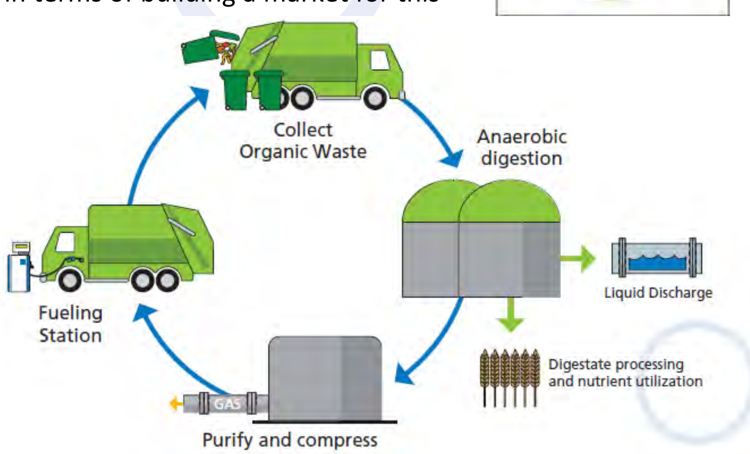
Currently, most biogas produced in Ontario is used to generate electricity, and is sold onto the grid through the Feed-in-Tariff program.

Some biogas in Ontario is upgraded to renewable natural gas (RNG), and injected into the natural gas grid. The Canadian Biogas Association and the Canadian Gas Association have come together to set a goal of 10% of the natural gas supply coming from renewable sources by 2030**.** Data from an Alberta Innovates study, and cited in the Canadian Gas Association's ***RNG Technology Roadmap***, indicates this is achievable when factoring in potential from gasification of biomass.



Greening the gas grid is also being considered by Quebec, and common policies between the two provinces may provide a range of benefits in terms of building a market for this renewable fuel. The Ontario Energy Board should be directed to value GHG emissions in submissions from natural gas utilities.

In Ontario, over 34% of our greenhouse gas emissions come from transportation. There is enormous potential to develop RNG as a vehicle fuel, to be blended with conventional natural gas in compressed natural gas (CNG) vehicles.

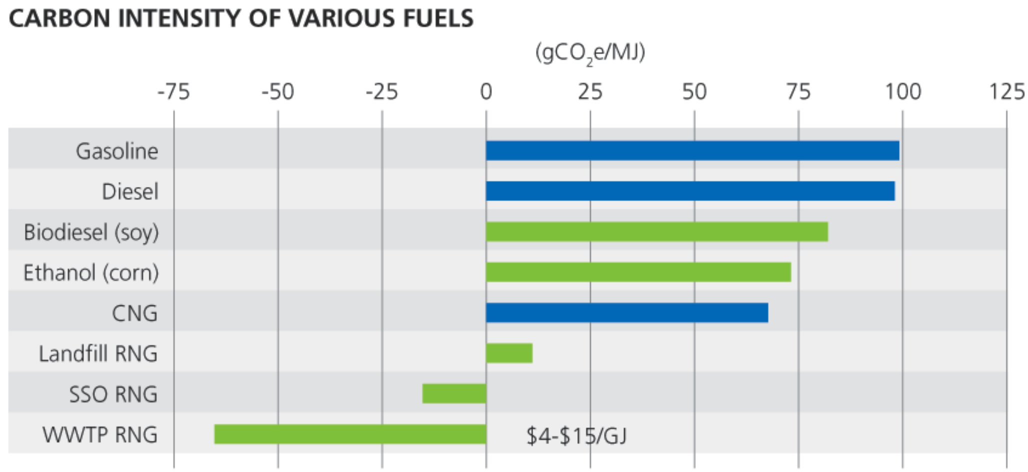


RNG and Climate Change

Ontario Government, March, 2016

RNG is recognized as a renewable fuel under the EPA's Renewable Fuel Standard (RFS). Under the RFS, RNG can be generated from landfills, municipal wastewater treatment facility digesters, agricultural digesters, and other organic wastes.

Fueling fleets with RNG can reduce GHG emissions by about 90% from diesel or gasoline, on average.



Data Source: Carbon Intensity Lookup Table for Diesel and Fuels that Substitute for Diesel, California Air Resources Board, 2012

What is Biogas?

- Biogas is a renewable source of methane gas, created when organic matter breaks down in an oxygen-free environment. This biological process is referred to as 'anaerobic digestion' (AD).
- The main component of biogas is methane, which is also the key component of natural gas, which means biogas can replace natural gas as a flexible fuel source.
- Biogas is much more than just renewable energy. It provides energy 24/7 – regardless of the weather - in the form of heat, power, and pipeline quality gas that can be used for transportation, household heating or industrial, commercial and institutional processes.

Environmental Benefits of Biogas

- Biogas reduces two critically important greenhouse gases — carbon dioxide (CO_2) and methane (CH_4) – helping communities meet GHG reduction targets and overall climate change initiatives.
  - CO_2 emissions are reduced when biogas replaces fossil fuel use (i.e. diesel or natural gas)
  - CH_4, which is 21 times more potent than CO_s as a greenhouse gas, is captured in the biogas process and is converted to energy.

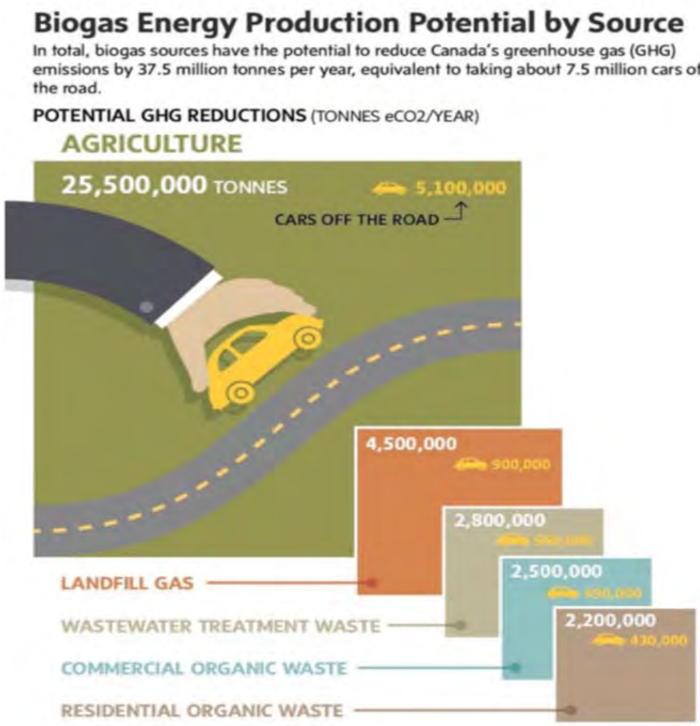


Image Courtesy of the Globe and Mail

- AD helps protect water quality by way of reducing pathogens up to 99% when compared to undigested manure and recycling nutrients for improved crop uptake, thereby reducing commercial fertilizer requirements and costs. AD systems are fully contained and managed reducing risks of pollution in soils, groundwater, and surface water.
- Biogas projects improve air quality by destroying volatile organic compounds (VOCs), and reducing odours from farms, waste processing facilities and landfills.

The Canadian Biogas Association

- The Canadian Biogas Association is the collective voice of the biogas sector, developing the biogas industry to its fullest potential through capturing and processing organic materials to maximize the utility and value inherent within that material.
- We are a not-for-profit, member-driven organization representing all components of the biogas sector including owners/operators, technology suppliers, financial and learning institutions, utilities, waste industry and organic residuals generators
- We serve our membership by guiding policy and regulatory development, building industry knowledge through exchange of information, creating knowledge networks and supporting research, and raising the general public's awareness of biogas's multiple environmental and societal benefits.

Renewable Natural Gas as a Complementary Measure

Industry and Government Discussion
March 30, 2016

Building the Biogas Sector With You

Canadian Biogas Association

Canadian Biogas Association

- Mandate
  - The collective voice of the biogas industry promoting development of biogas to its fullest by capturing and processing organic materials through anaerobic digestion to maximize the utility and value inherent within that material
- Roles
  - Education and outreach
  - Advocacy and policy
  - Research

Member Partners

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Executive Summary

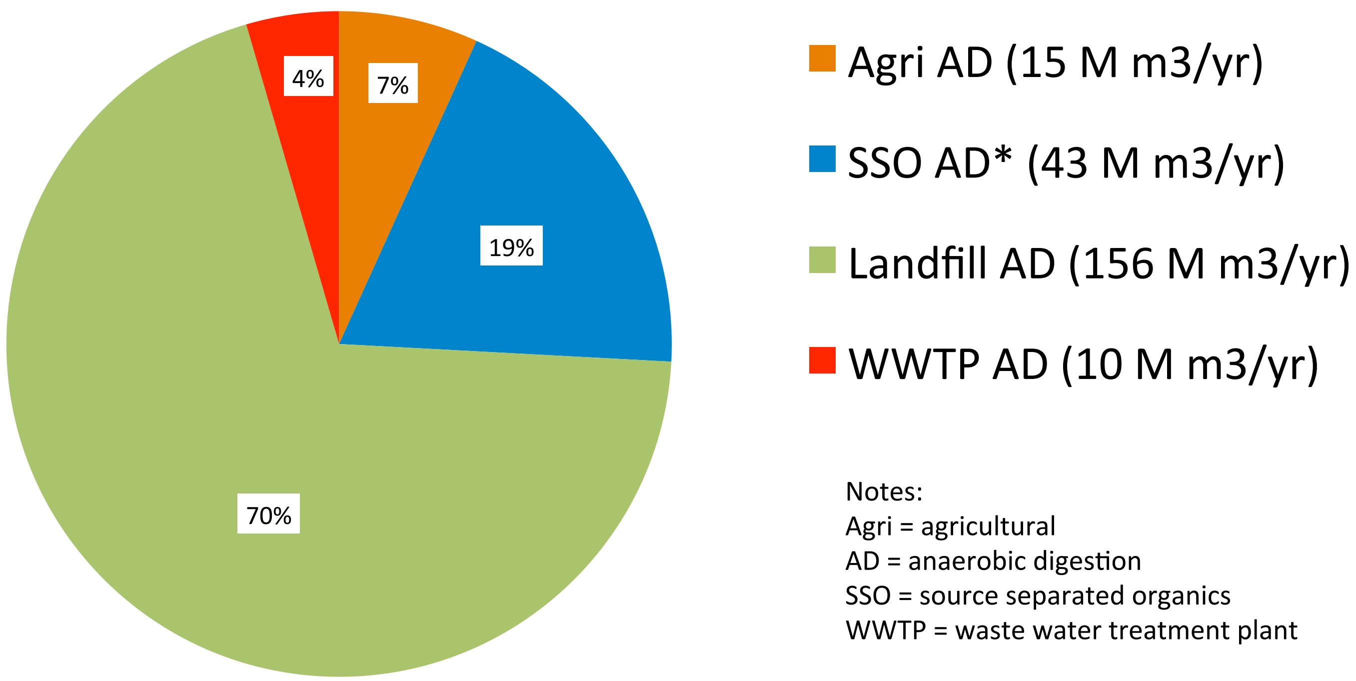
- The CBA is asking for a mandate within the Climate Change Action Plan to set RNG targets, as follows:
  - up to 2% of Enbridge and Union Gas system gas supply by 2020
  - Technical potential of 16% of all natural gas consumed in Ontario by 2030. CBA proposes a conservative target of 10% in this same timeframe.
- To achieve the RNG target, establish a renewable portfolio standard (RPS) which allows Ontario's natural gas utilities to actively manage the procurement of RNG
- Utilize a portion of the Greenhouse Gas Reduction Account to support the Renewable Natural Gas (RNG) market and help lower costs for Ontario RNG development
- Expedite the development of an "Organic Waste Digestion" protocol and consideration for offsets

Emissions Reduction

- Replacement of up to 16% of Ontario's conventional natural gas supply with RNG by 2030 can reduce Ontario emissions by up to 8.1 $MtCO_2e$

Ontario RNG Potential by 2020

Forecast of AD based RNG by Waste Stream



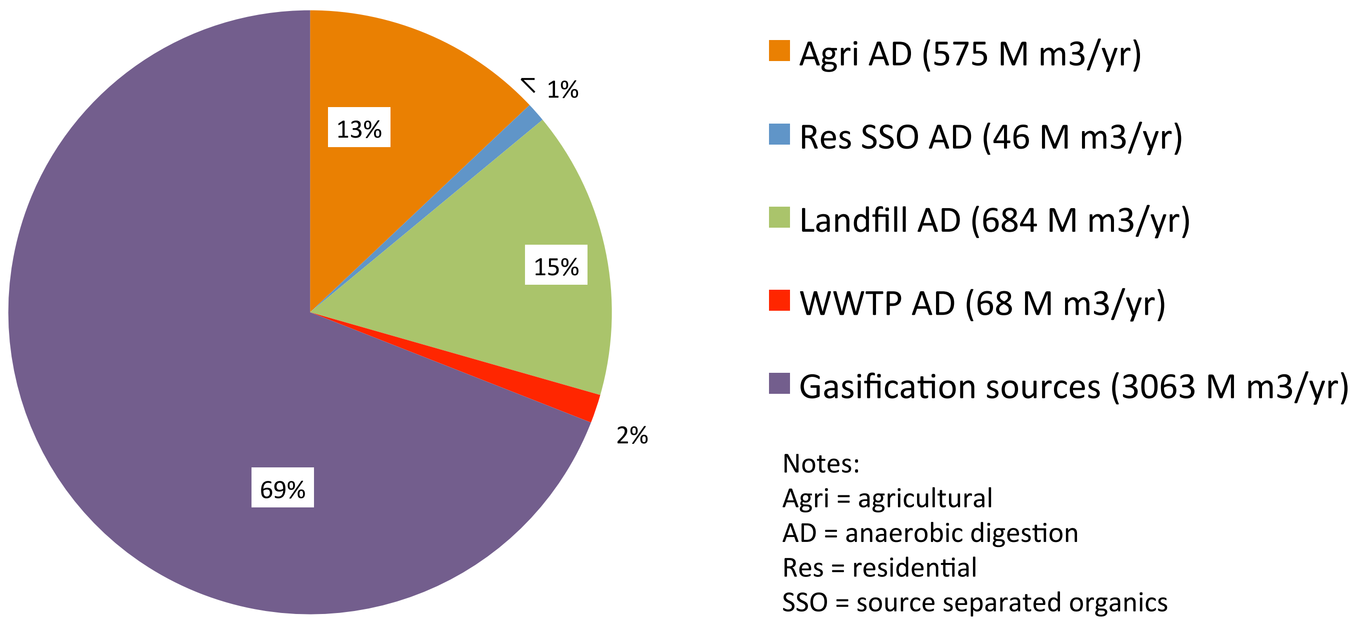
Notes:
Agri = agricultural
AD = anaerobic digestion
SSO = source separated organics
WWTP = waste water treatment plant

Source: Distribution of RNG project types as forecasted by utilities. RNG volumes based on 2% of utility system supply (223 M m3/yr).

*Includes residential and commercial source separated organics

Ontario RNG Potential by 2030

Total RNG Potential (4435 M m3/yr) by Source



Notes:
Agri = agricultural
AD = anaerobic digestion
Res = residential
SSO = source separated organics
MSW = municipal solid waste
WWTP = waste water treatment plant

Source: Alberta Innovates Technology Futures, **Potential Production of Renewable Natural Gas from Ontario Wastes**, May 2011

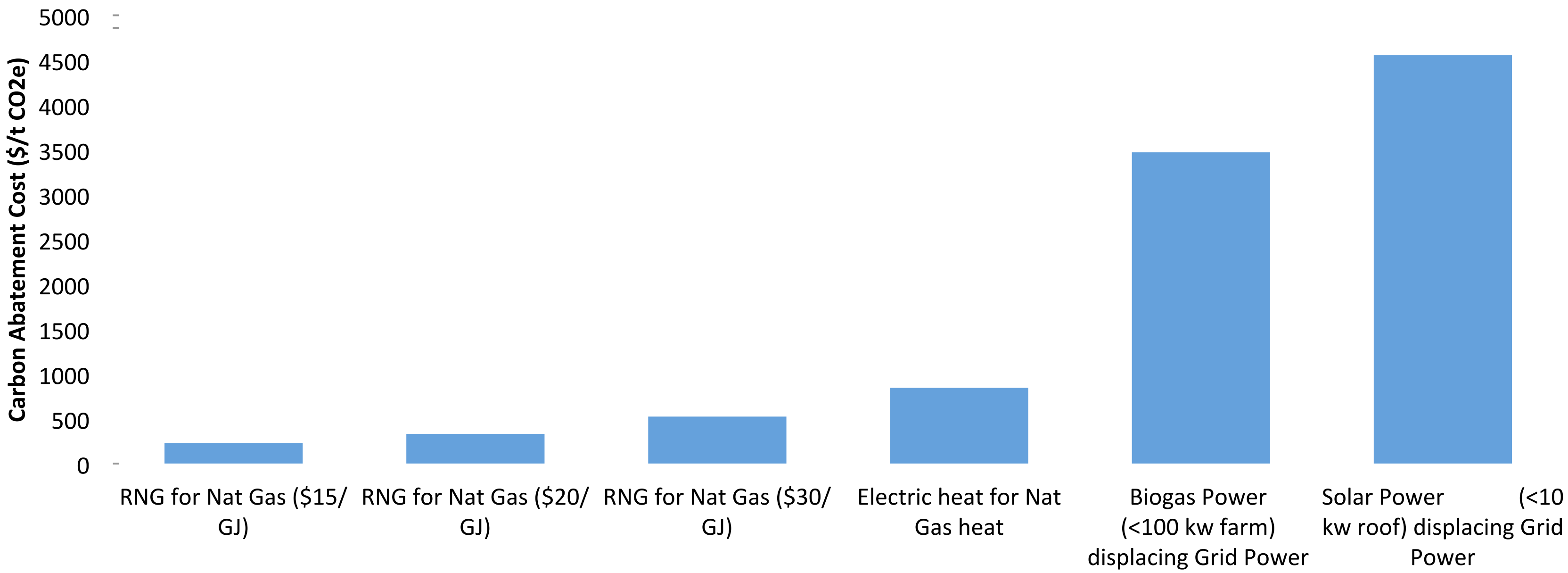
Addressing the Economic Barrier

- There is no technology barrier to bringing on immediate supplies of biogas and landfill gas
- The barrier is lack of price and stable market for RNG producers
  - No equivalent in Ontario to FIT biogas-electric market
  - No plan to utilize cap and trade proceeds to provide incentives to connect, upgrade and produce RNG
- Markets for RNG have been established in competitive jurisdictions within the US, such as California
- Largest landfill in Canada (Quebec) started selling RNG to California in 2015

Renewable Portfolio Standard

- Ministry of Energy to provide policy direction to the Ontario Energy Board (OEB) for Enbridge and Union to establish a Renewable Portfolio Standard
- Target up to 2% of system supply by 2020 and up to 16% by 2030
- Pricing and commercial framework allowing utilities to competitively purchase RNG at prices required to support production and meet the targets
- Contract supply terms that allow utilities to procure RNG from Ontario producers on long term contracts (5 – 20 years)
- RNG procured by utilities will be gas for system customers under an OEB approved process

Carbon Abatement Costs by Fuel Switching Scenarios



Assumptions:

Energy	Costs	Carbon Intensity	Notes and References
Nat Gas	$3/GJ	1.9 kg/m3	1 m3 nat gas = 0.0372 GJ 2014 BC Ministry of Environment- Table 2 source emission factors
Grid Electric	$0.133/ kwh	0.04 kg/ kwh	LTEP: Comparison of Forecast vs. 2014 Actual Results (6.8 Mt CO2/164 TWH) Residential electricity price $0.133/kwh Grid generation price $130/MWH
RNG	$15-30/GJ	0.01 kg/m3	2014 BC Ministry of Environment- Table 2 source emission factors
Biogas Power	$0.263/kwh	0.002 kg/kwh	40% electrical efficiency with RNG emission factor 2016 FIT price for <100kw on farm biogas
Solar Power	$0.294/kwh	0.005 kg/kwh	2016 µFIT price for <10 kw rooftop solar Minimum lifecycle GHG emissions for PV solar from aggregated literature review (IPCC, 2011)

Next Steps

- MOECC to include phased in RNG targets as proposed in the Climate Change Action Plan
- Ministry of Energy to provide policy direction to the OEB for Enbridge and Union to establish a Renewable Portfolio Standard
- Establish a Working Group immediately to craft the RPS design details:
  - MOECC, MoE, MEDI, OMAFRA
  - Industry representatives (CBA, OFA, OWMA)
  - Enbridge, Union Gas
- Create a framework for procurement to incent the largest volumes and lowest unit cost of abatement (i.e. rate base, offsets, application of cap and trade proceeds)

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Building the Biogas Sector With You

Canadian Biogas Association

Decarbonizing the Gas Supply:

Renewable Natural Gas & Hydrogen

ENBRIDGE®

External Affairs Canada

June 07, 2017

Enbridge: An Evolving Energy Company

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

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Life Takes Energy

Who is Enbridge?

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

Enbridge in Ontario:

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

uniongas
An Enbridge Company

ENBRIDGE
Enbridge Gas Distribution Inc.

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Why Renewable Natural Gas & Hydrogen?

Decarbonizing the Gas Supply

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

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

Next Steps for Utility-led Renewable Natural Gas

Decarbonizing the Gas Supply

- Ontario's Climate Change Action Plan (CCAP) states that Ontario intends to create a renewable content requirement for natural gas and will provide $60M to 100M in support for RNG
- CCAP also supports refueling infrastructure and vehicle subsidies to move heavy-duty diesel transportation to natural gas (15% GHG emission reduction, further with RNG/hydrogen)
- Expect Ontario's Minister of Energy to direct the Ontario Energy Board (OEB) to establish a renewable portfolio standard (RPS) for Ontario's natural gas utilities, providing a mandate to source sufficient RNG to meet a government target (ie. 2% of system supply requirement by 2021 or 5% by 2030)

Next Steps:

- Encourage favourable offset protocols development that support RNG development (landfill gas & organics)
- OEB application and hearing process regarding meeting government targets
- Encouraging Ontario's 'Waste-Free Ontario' strategy to recognize Ontario's significant targets for RNG as part of its organics diversion plan; as well as the need for centralized organics processing where possible

Integration of Renewable Natural Gas

A Plan to Harness RNG for Ontarians

Enbridge Gas Distribution / Union Gas Limited
For Discussion

Framework Proposal

To Drive an RNG Market in Ontario

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Enbridge and Union Seek

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

RNG Gap Funding Proposal

Illustrative Example

RFP Price of RNG of $13.50/GJ

$5.00/GJ	$2.50/GJ	$6.00/GJ
Customer Cost of Natural Gas (“WACOG”)	Covered through Cap and Trade Compliance Plan (“WACC”) at $50/tonne	RNG Enabler

Carbon Abated Cost of Natural Gas
$7.50/GJ

Cost Covered by CCAP Funding
$6.00/GJ

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

RNG Created from CCAP funding and Offset Value

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

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

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

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Operational Details

Utility Role in RNG Development

Utilities will administer RNG supply arrangements for GreenON

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

Key Differences between Ontario and Quebec

Early Mover Advantages for Quebec

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

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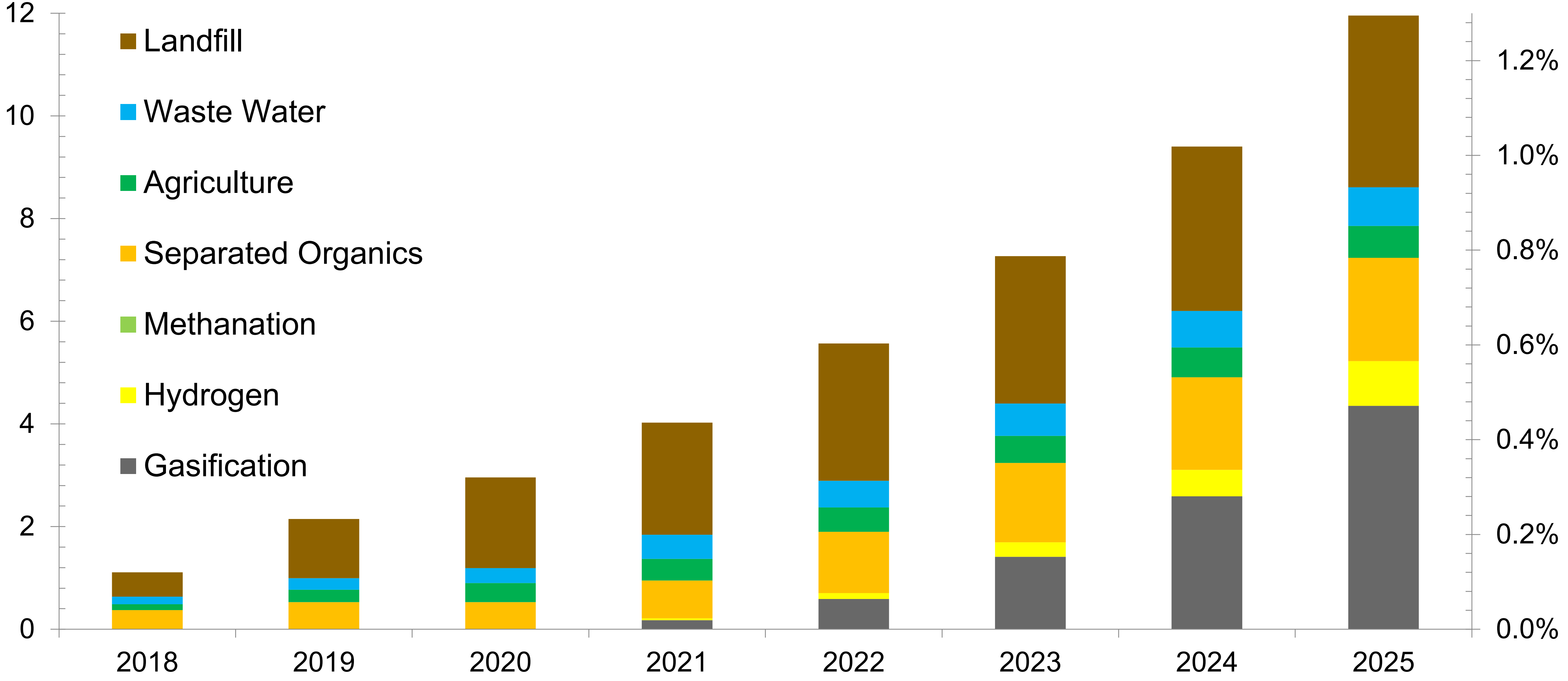
Renewable Natural Gas Volumes

PJ Total Supply Potential and Percentage of Total Throughput



Questions

Comparing Abatement Opportunities and their Costs

Estimates on RNG Costs $/tonne

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

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

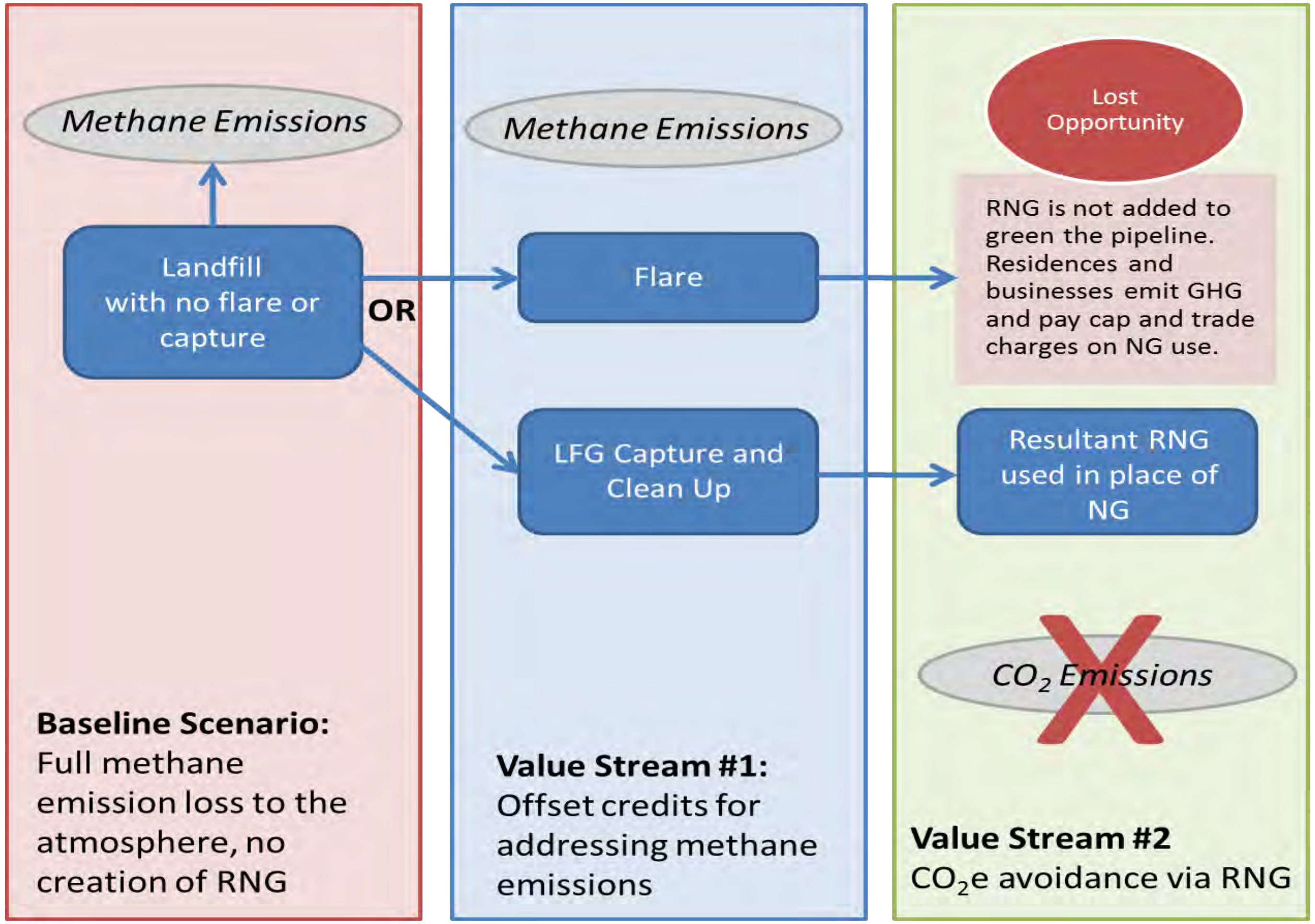
Offset Protocols

Addressing the 'Double Counting' Issue

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

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

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



Key Takeaways

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

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

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

Integration of Renewable Natural Gas

A Plan to Harness RNG for Ontarians

Enbridge Gas Distribution / Union Gas Limited
For Discussion

An Enbridge Company

Driving a Ontario RNG Market

Enabling a Nascent Market

Enbridge and Union Seek

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

Benefits

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

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Options for Implementation

Unintended Cost Consequences

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

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RNG Gap Funding Proposal

Illustrative Example

RFP Price of RNG of $13.50/GJ*

$5.00/GJ*

Customer Cost of Natural Gas ("WACOG")

$2.50/GJ*

Covered through Cap and Trade Compliance Plan ("WACC") at $50/tonne

$6.00/GJ*

RNG Enabler

Carbon Abated Cost of Natural Gas $7.50/GJ*

Cost Covered by CCAP Funding $6.00/GJ*

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

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RNG Created from CCAP Funding

Investment Drives Low Cost Abatement

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

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

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

Enabling RNG

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Utilities Role in RNG Development

The Utilities are prepared to make RNG a success in Ontario

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

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

Key Takeaways

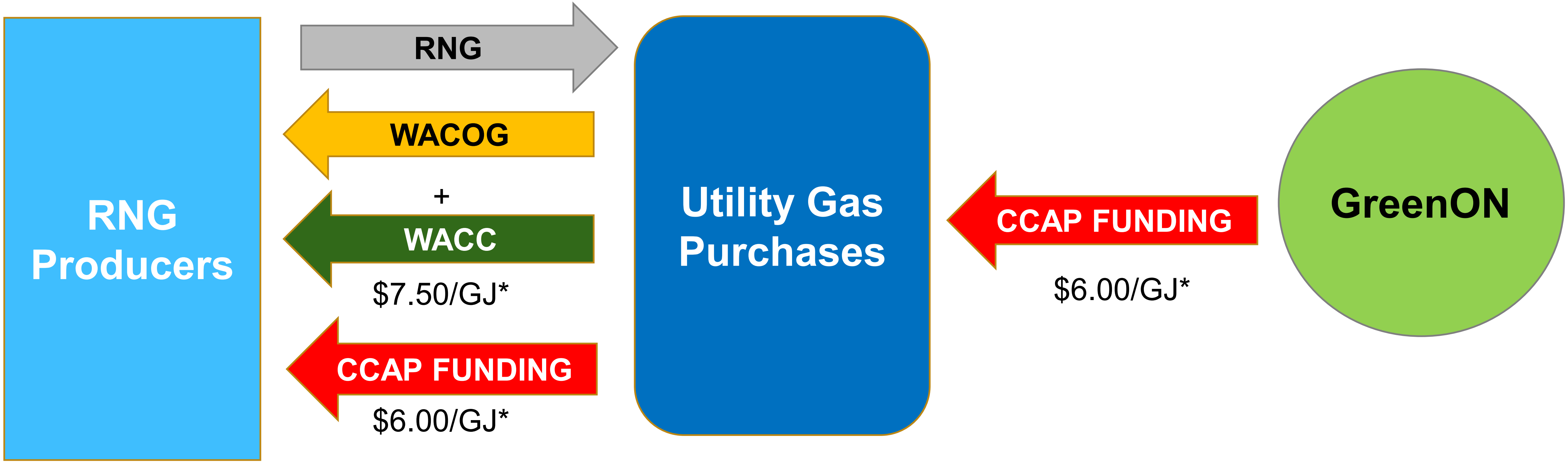
Delivering RNG Effectively to Customers

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

Questions

Operational Model

Option A – Utilities administer and execute with CCAP funding assistance

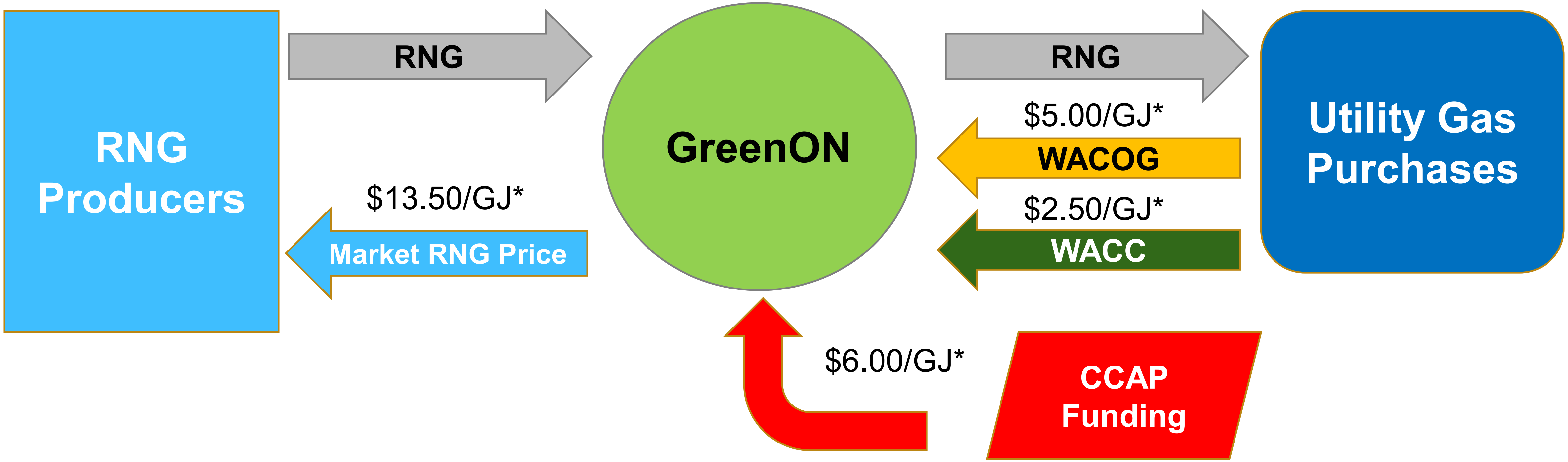


- CCAP will fund RNG for Utilities at $6.00/GJ*
- Utilities will contract for RNG at $13.50/GJ* based on $7.50/GJ* Carbon Abated Cost on Natural Gas plus $6.00/GJ from CCAP

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

Operational Model

Option B – Utilities procure RNG from GreenON and facilitate market



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

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

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Key Differences between Ontario and Quebec

Early Mover Advantages for Quebec

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

Integration of Renewable Natural Gas

A Plan to Harness RNG for Ontarians

Enbridge Gas Distribution / Union Gas Limited
For Discussion

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Driving a Ontario RNG Market

Enabling a Nascent Market

Goals:

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

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

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

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RNG Funding 'Gap'

Illustrative Example

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

$5.00/GJ*

Customer Cost of Natural Gas ("WACOG")

$1.50/GJ*

Covered through Cap and Trade Compliance Plan ("WACC")

$9.50/GJ*

RNG Enabler

Carbon Abated Cost of Natural Gas
$6.50/GJ*

Cost Covered by CCAP Funding
$9.50/GJ*

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

Timeline to Implementation

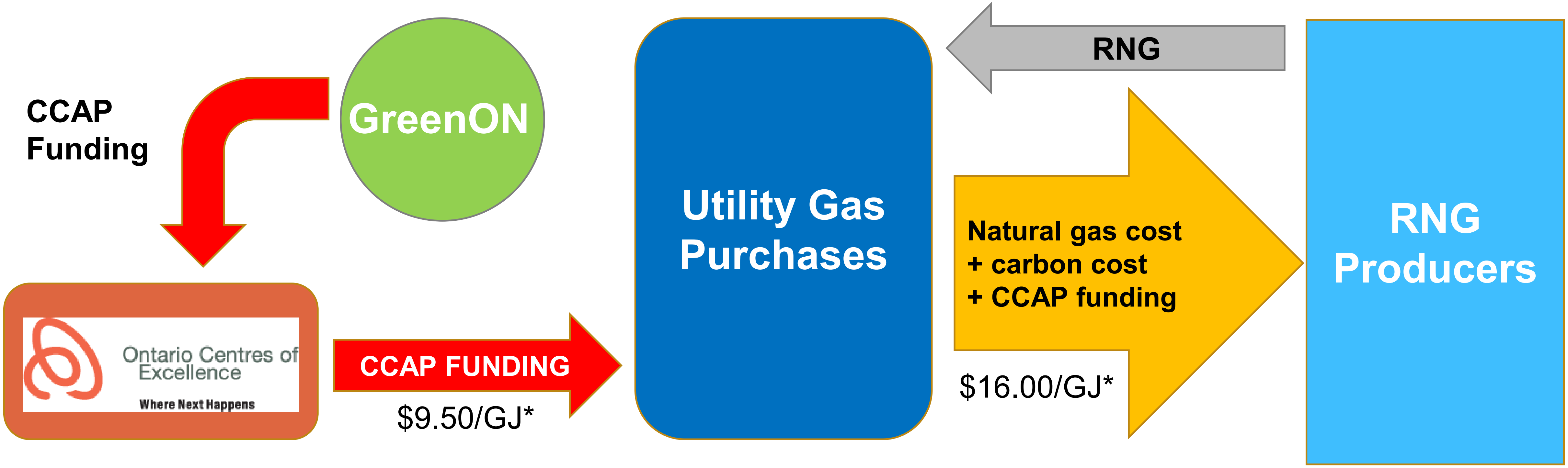
Nov 2017 - Enbridge Gas and Union Gas filed 'Cap & Trade Compliance Plans' with the Ontario Energy Board (OEB) requesting early approval to acquire RNG based on 10-year RNG procurement agreements, a 10-year forecast of conventional natural gas prices and the OEB's 10-year forecast of carbon; pending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

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

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

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

Operational Model



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

****Illustrative Pricing***

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Decarbonizing Ontario's Natural Gas Supply

Investment In Renewable Natural Gas Drives Low Cost Abatement

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

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

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

**2016 Total System Supply was 430PJ*

Enabling RNG

Utilities Role in RNG Development

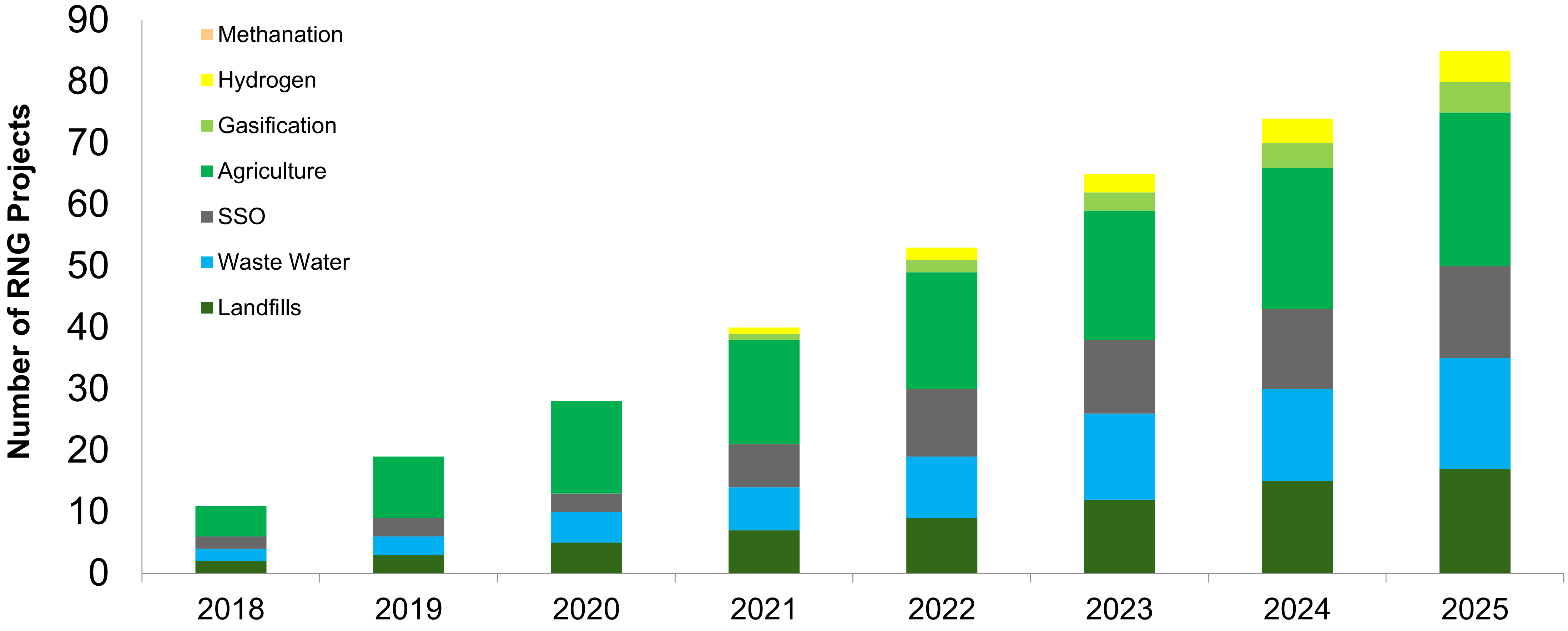
The Utilities are prepared to make RNG a success in Ontario

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

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

Appendix

Potential Number of Ontario Projects by Contracted Year



Renewable Natural Gas Projects in Ontario

Harnessing Ontario's Ready RNG Projects

An Enbridge Company

Enbridge Gas Distribution / Union Gas Limited
For Discussion

Filed: 2018-01-19
EB-2017-0255
Exhibit B.Energy Probe.2
Attachment 1
Page 2 of 5

Ontario RNG Market Projects

Enabling a Nascent Market

Funding Requirements

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

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

*RNG flow date 1-3 years post contract

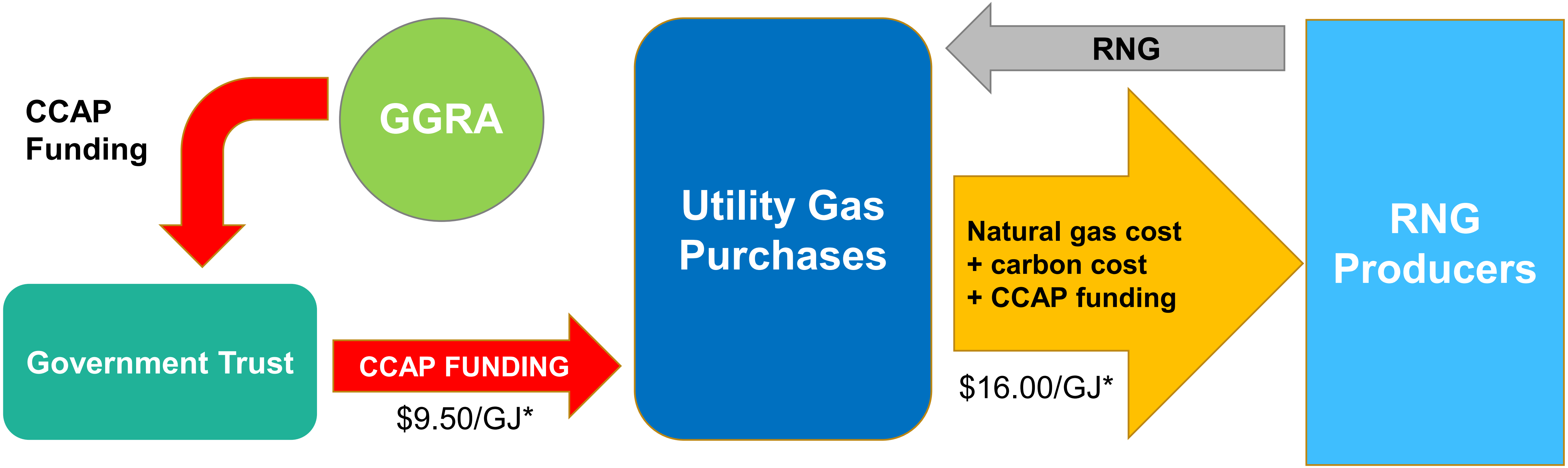
Legend:
Small < 60,000 GJ/yr
Medium 60,000 <> 250,000 GJ/yr
Large > 250,000 GJ/yr

Alternative Implementation to a Trust

Funding Distribution Mechanisms

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

Option A: Operational Model



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

Illustrative Pricing

Option B: Operational Model

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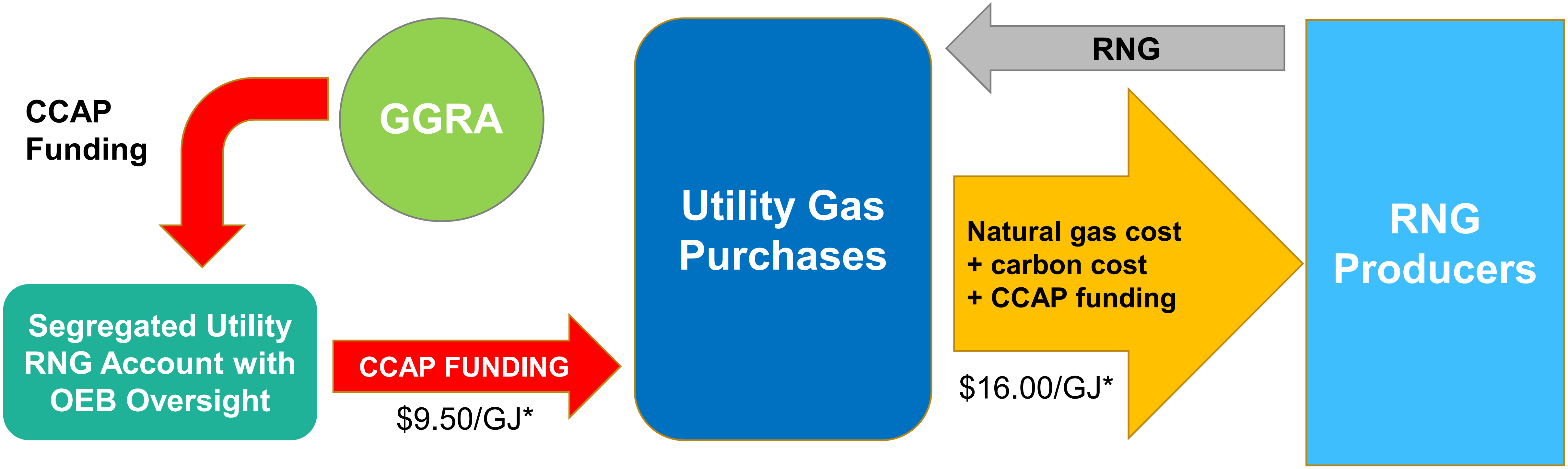


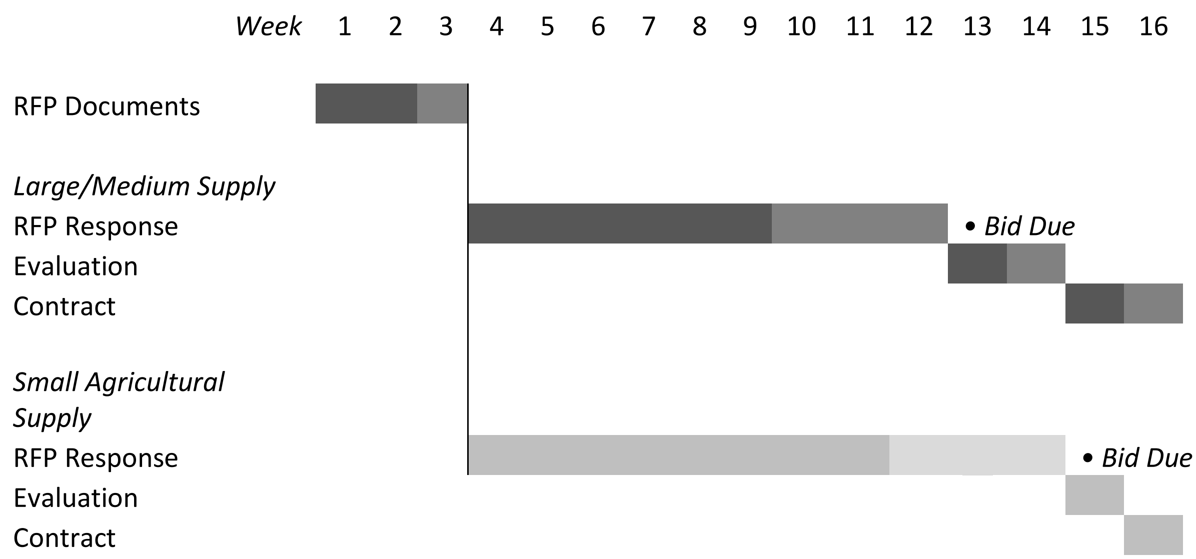
- RNG bid at $16.00/GJ*, commodity at $5.00/GJ* and OEB Mid-Range Long Term Carbon Price Forecast at $1.50/GJ* with CAPP funding the difference

Illustrative Pricing

Draft Renewable Natural Gas (RNG) Implementation Discussion Paper

Timeline

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



Request for Proposals Process

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

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

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

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

Evaluation Steps for RFP

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

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

Contract Offer Lists

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

Post Contract Award

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

RFP Details/Specifics

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

RNG Supplier Selection Criteria

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

A scoring matrix will be used with the following criteria:

Primary Attributes

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

Secondary Attributes

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

Mandatory Requirements

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

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

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

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

RNG Supply Contract Length

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

Other RNG Contract Features

Payment for RNG

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

Quality Compliance / Volumes

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

Contracts for Biomethane (RNG) Supply

Union Gas Limited:

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

Gas Purchase Agreement

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

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

M13 Transportation, Producer Balancing and Name Change Service

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

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

Injection Service

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

Biomethane (RNG) Contract

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

Optional Utility Biogas Cleanup (Upgrading) Service

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

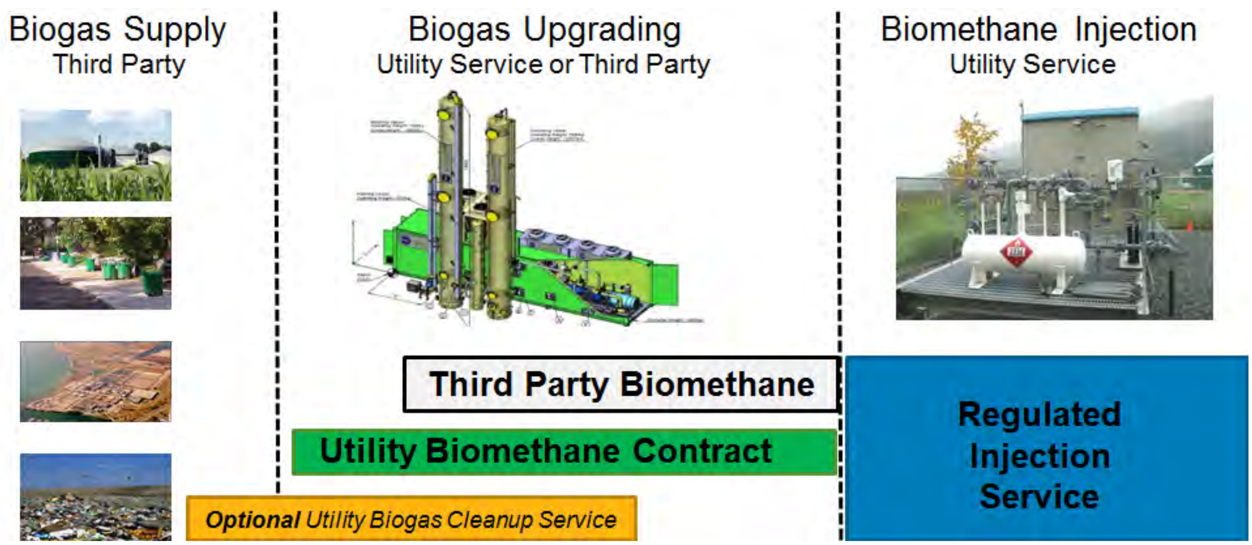
- Technology selection choice by Utility
- Take or pay contract
- Ensure capital recovery of assets, and fixed operating expenses
    - Net Book Value (NBV) plus compensation for cancelled contracts
    - Negotiated provision of services to plant - Water, electricity, land lease
    - Access to all pre-treatment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

Cost Components

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

A: Biomethane Producer Costs

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



OEB Regulation of RNG Program Contracts

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

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

OEB Value for Money Oversight

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

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

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

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

Less

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

Less

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

Equals

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

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

Summary

Total Annual RNG Volumetric Payments

Less

Long Term Forecast Cost of Gas

Less

Carbon Abatement Costs

Equals

Amounts Paid from the RNG Program Fund

Reporting

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

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

RNG Supply Disposition

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

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

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

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

Within the OGU are:

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

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

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

Administration Costs

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

Co-Benefits for Government

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

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

Data on the following would likely be accessible as measures:

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

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

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit 3, Tab 4, Pages 18-20 and Figure 3

Preamble: The OEB-issued MACC also identified that RNG is not a cost-effective measure relative to the cost of carbon. In order to advance the adoption of RNG in support of provincial GHG emission targets and incent the development of the RNG market, additional provincial funding and MOECC program support is required. This will also provide RNG in a cost-effective manner for Union's customers and cost recovery for the utility.

Question:
a) Please provide a schedule/calculation that provides the benefit/cost of RNG for a typical Union customer. List all key assumptions.
b) Compare to a carbon tax, at certain levels similar to BC and other jurisdictions.
c) Compare RNG to other alternatives such as Residential DSM using the same assumptions.

Response:

a) Union's proposal contemplates government funding to keep customers financially indifferent to the cost of RNG compared to conventional natural gas. The primary benefit of RNG is that it is a renewable carbon neutral fuel source resulting in lower carbon emissions. Therefore, Union is not required to procure carbon allowances or credits related to emissions from RNG that is consumed by Union or its customers. In addition, the forecast impact to rate payers of Union's RNG purchases will be no different than the cost of conventional natural gas supply plus the associated carbon cost. Provincial funding will offset the difference between the total RNG price and the forecast cost of conventional natural gas supply plus the forecast cost of carbon over the term of the RNG contract.

   By investing in and supporting RNG, Ontario and Union's ratepayers will benefit from the diversification of Union's gas supply portfolio, and the development of an Ontario RNG market that supports the transition to a low carbon economy. RNG provides an alternative to conventional natural gas that reduces customer and facility emissions and ensures that the energy infrastructure that exists for natural gas in Ontario remains used and useful. Please see the response at Exhibit B.Staff.1.

b) Union cannot comment on how the avoided cost of carbon may differ under a carbon tax regime in Ontario versus Ontario's current Cap-and-Trade program. Using the Pan-Canadian Framework on Clean Growth and Climate Change as an example, carbon must be priced at a minimum of $10 per tonne in 2018, raising by $10 per year to $50 per tonne by

2022 under a carbon tax. The federal government has stated its intention that after 2022, a review will be done to determine the rate of price growth going forward.

Under the existing Ontario Cap-and-Trade program, the OEB Long Term Carbon Price Forecast mid-range forecast shows carbon prices at $17 per tonne in 2018, raising to $22 per tonne by 2022, and $71 per tonne by 2028. Based on this example, under a carbon tax the benefits and associated costs of the carbon abatement value of RNG would be lower in 2018, but much higher in 2022 relative to the existing Ontario Cap-and-Trade program.

c) Please see the response at Exhibit B.Staff.1 f).

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit 3, Tab 4, Page 19

Preamble: Earlier in 2017, Union and EGD developed an RNG proposal for the Province that will achieve the market objectives of the province by providing a mechanism to facilitate RNG procurement funding and cost recovery. This RNG proposal provides:

- Long-term, fixed price contracts with producers that supports the development of RNG in Ontario, consistent with CCAP objectives of long-term emissions reductions;
- Utilization of government funding to purchase RNG while minimizing the impact to ratepayers relative to the cost of conventional natural gas supply; and,
- Regulatory efficiency through the use of existing regulatory frameworks and mechanisms to procure RNG for ratepayers and to diminish the need for further regulatory process.

Question:

a) Did Union use the E.B.O.188 Feasibility framework (Phase I Phase II and III) to compare supply alternatives such as RNG and demand reduction options?

b) If so please provide this analysis. If not please explain why this has not been done prior to requesting pre-approval for RNG procurement?

c) Please provide Union's view of the difference(s) between Government Project funding and Carbon Tax Revenue.

Response:

a) No.

b) EBO 134 (3-Stage Approach) and EBO 188 (Portfolio Approach) are OEB-approved methods to analyze the quantitative and qualitative aspects of a project before investing capital. In this application, Union is not evaluating the investment in infrastructure to produce RNG, but rather facilitating the introduction of RNG into the natural gas supply mix.

   Union's RNG proposal is structured such that at the time of contracting, customers are indifferent between purchasing compliance instruments and including RNG in the gas supply portfolio. That is, the cost of RNG recovered from customers would equal the forecast cost of conventional natural gas plus the forecast cost of carbon. The difference between the market price of RNG and the cost recovered from customers would be funded from the provincial government's Climate Change Action Plan ("CCAP"). The intent of this approach is to encourage development of the RNG market while leaving customers financially indifferent to conventional natural gas compared to RNG.

Therefore, E.B.O. 188 Feasibility Framework (Phase 1 Phase II and III) is not applicable and was not conducted. Please also see the response at Exhibit B.Staff.1 f).

c) Union's use of "government funding" in Exhibit 3, Tab 4, refers to CCAP funding or any other government funding available to support GHG emission reduction initiatives, regardless of how those funds are sourced. Ontario's CCAP program is funded through the proceeds resulting from Ontario's Cap-and-Trade program, and not from a carbon tax. A carbon tax is an alternate form of carbon-pricing mechanism.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit 3, Tab 4, Page 20; Exhibit 3, Tab 4, Page 22

Preamble: Union expects to enter into fixed price RNG procurement contracts with terms up to 10 years in duration, subject to provincial funding. Based on these RNG contracts, Union will then enter into a contractual arrangement with the province to provide provincial funding equal to the difference between the fixed price of RNG contracted with the producer, and the cost of conventional natural gas plus the avoided cost of carbon. The inclusion of the avoided cost of carbon is to recognize that customers would have incurred a carbon cost in the absence of RNG.

This represents the premium for RNG, as illustrated in the numerical example in Figure 3.

Question:
a) Please indicate the timing of the RFP(s)
b) Will these be regional-based?
c) Will Union conduct the RFP/tender(s) with Enbridge and/or NRG/EPCOR. Please discuss.
d) Please explain why a 10-year term is appropriate for existing RNG supplies such as landfill gas?
e) Will the tender(s) be based on a landed cost? If so, please provide an example, including gas quality, transportation, clean up and compression. If not, provide details of how the bids will be evaluated.
f) Will EGD request Board Approval of the specific RNG Contracts?

Response:

a) Union plans to issue an RFP for the purchase of RNG by early February 2018. The RFP will be conditional upon receiving funding commitments from the Ministry of the Environment and Climate Change and approval from the OEB for Union's RNG proposal as requested in this proceeding.

b) No. Union's RFP will not be regional-based. Union's RFP will encompass all potential RNG supply that can be delivered to Union's franchise area.

c) Union is working closely with EGD to coordinate the RNG RFP process. However, each utility will conduct separate RFP processes and will contract supply for their own respective franchise areas. Union is not aware of any plans by NRG/EPCOR related to the procurement of RNG.

d) Please see the response at Exhibit B.Staff.5.

e) Tenders will be evaluated based on a series of selection critieria, with landed cost being a primary criteria. Union expects that respondents to the RFP will consider all costs associated with RNG production in providing pipeline quality RNG supply that is ready to inject into Union’s system.

Union will also consider the expected in-service timing, term of contract, supply source and location, and operator capability.

f) Union’s response assumes that the interrogatory is meant to refer to Union and not EGD. No, similar to its gas purchases, Union will not request OEB approval for specific RNG purchase contracts. Union is seeking approval of the proposed RNG funding mechanism as part of this proceeding. Costs associated with procurement of RNG will be brought before the OEB for recovery as part of existing regulatory mechanisms (i.e. QRAM).

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit 3, Tab 4, Page 21 and Figure 3

Preamble: The following is an example to show how the mechanism will work in principle. In this example, Union has assumed the following:

- 2018 forecast carbon price of $17.00 (based on the OEB LTCPF mid-range scenario) for rate setting purposes. This equates to a rate impact of approximately $0.85/GJ.
- Long-term contracted RNG price of $16.00/GJ
- 2018 forecasted cost of conventional natural gas of $3.91/GJ

Question:

a) Please provide the natural gas and carbon price forecasts used in the example and Figure 3.
b) Is Union proposing $16/GJ for RNG or is this a high level estimate? What evidence is this figure based on?
c) Please indicate the natural gas delivery point(s) assumed and the landed cost/m3, including storage and transportation.
d) Please indicate the assumptions and resulting landed cost for RNG equivalent.
e) Provide the estimated annual benefit/cost of RNG to an average Union South and Union North residential customer.
f) Please discuss in detail based on Figure 3, and the responses, why RNG is the most viable option for abatement of residential GHG compared to purchasing credits.

Response:

a) Please see Attachment 1 for the natural gas forecast used in the example. The carbon price forecast is based on the OEB LTCPF mid-range scenario, converted to $/GJ. Attachment 1 also includes the conversion methodology used to convert $/tonne CO_2e to $/GJ.

b) Please see the response at Exhibit B.Staff.6 b).

c) In the illustrative example, Union has assumed for 2018 that RNG will replace supply landed at Dawn at $3.91/GJ.

d) In the illustrative example, Union has assumed a landed cost of $16.00 for RNG. The actual cost of RNG will vary based on each individual RNG project and its underlying costs. The actual cost of RNG that Union purchases will be determined through the RFP process.

e) Please see the response at Exhibit B.Energy Probe.3 a).

f) Please see the response at Exhibit B.Staff.1 f).

Forecast Natural Gas Price

Line		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
a	Dawn[1]	3.51	3.54	3.51	3.78	3.79	3.85	3.84	4.20	4.51	4.87
b	Foreign Exchange[2]	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
c	MMBtu to GJ conversion	1.05505	1.05505	1.05505	1.05505	1.05505	1.05505	1.05505	1.05505	1.05505	1.05505
d = a/b/c		3.91	3.95	3.91	4.22	4.22	4.29	4.28	4.68	5.03	5.43

1 - Dawn forecast is from ICF Q3 base case forecast and is in nominal USD/MMBtu

2 - Foreign exchange rate is the same rate used in the OEB LTCPF

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit 3, Tab 4, Pages 22-23

Preamble: Since Union's ability to procure RNG is dependent on funding, Union has not included any RNG in its gas supply portfolio for 2018 and has not reflected any related GHG emissions reductions in the 2018 Compliance Plan. However, as highlighted above, customers would incur costs equal to the forecast cost of conventional natural gas plus the forecast avoided cost of carbon.

If Union is successful in acquiring RNG supply in 2018, the quantity is expected to be small in relation to Union's 2018 compliance obligation. Any GHG emission reductions realized in 2018 will be reflected in actual activity, and Union's gas supply purchases and compliance instrument procurement will be adjusted accordingly.

Question:

a) Given that the greater-than-market costs of RNG will be covered from funds collected from the cap-and-trade policy, what percentage of Ontario's cap-and-trade money will come from natural gas customers?
b) Please explain in more detail the impacts in 2018 of Union's RNG proposal on the distribution costs for residential customers and how these will be flowed into rates in 2018 and beyond. In responding, discuss in context of Union and Enbridge (Amalco) application for a Rate Setting Mechanism for 2019 and beyond.

Response:

a) Union cannot determine the actual percentage of Cap-and-Trade funds that come from natural gas customers as these proceeds are dependent on utility procurement plans and the execution of those plans. Utility procurement plans are Strictly Confidential.

   However, Union can provide a rough estimate based on utility emissions as a percentage of the total Ontario cap. As outlined in Attachment 1, using 2017 reported utility emissions as a percentage of the total 2017 Ontario cap, Union calculates that approximately 26% of Ontario's Cap-and-Trade proceeds will come from natural gas customers. Union notes that RNG funding is between (1.3% - 1.7%) of total estimated Climate Change Action Plan funds.[1]

[1] This is based on estimated RNG funding of $100 million compared to total CCAP funds in the range of $6 billion to $8 billion, as outlined in the CCAP.

b) Union's RNG proposal has no impact on distribution costs.

The RNG proposal costs to be funded by ratepayers include costs equal to the forecasted cost of conventional natural gas supply and the avoided cost of carbon. The forecasted cost of conventional natural gas supply will be recovered through gas supply commodity rates. The avoided cost of carbon will be recovered through Cap-and-Trade customer-related and facility-related rates. Within Union's 2018 Cap-and-Trade Compliance Plan compliance cost, RNG reduces the emission volumes for which Union will be required to procure compliance instruments, which will be offset by an increase in the cost of abatement. The abatement costs will be allocated in proportion to the customer-related and facility-related compliance obligation. Any variance between the costs included in rates and the actual gas supply commodity costs and the Cap-and-Trade costs, including the forecast cost of supply and carbon in RNG proposal costs, will be tracked in the respective gas cost and Cap-and-Trade deferral accounts.

Union does not anticipate that the RNG proposal will impact the Union and EGD application for a Rate Setting Mechanism, as the gas supply commodity rates are set through the Quarterly Rate Adjustment Mechanism and Cap-and-Trade rates are set through the Cap-and-Trade Compliance Plan proceedings.

Please see the response at Exhibit B.Staff.6.

Estimated Proceeds of Cap-and-Trade Funds from Ontario Utilities

	2017 forecasted utility emissions[1]:	**Tonnes CO2e (unless otherwise stated)**
a)	Union	15,604,137
b)	EGD	21,137,676
c)	NRG	60,719
d)	Total 2017 forecasted emissions	36,802,532
e)	2017 Ontario cap[2]	142,332,000
(f) = (d)/(e)	Utility % of Ontario total	26%

Footnotes:
1 - 2017 Forecasted utility emissions for Union, EGD and NRG are from EB-2016-0296, EB-2016-0300, and EB-2016-0330, respectively.
2 - https://www.ontario.ca/page/cap-and-trade-program-overview

UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Reference: Exhibit 3, Tab 4, Page 17, footnote 7

Preamble: We would like to understand better the government's stated support of RNG as an abatement strategy for the utilities. Footnote 7 references page 74 of the LTEP report which, in part, reads: "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."*

Question:

1) The last sentence in the reference states RNG does release any additional carbon into the atmosphere. As Union understands this statement:
   a) Does RNG methane produce carbon emissions comparable to fossil fuel methane? If not, please clarify the difference.
   b) Understood in context, what does the "additional" refer to in the last sentence?

Response:

a) Assuming that the energy content of the RNG and conventional natural gas is comparable, RNG methane produces carbon emissions comparable to fossil fuel methane. However, CO_2 emissions from RNG are considered CO_2 neutral, for the purposes of determining Cap-and-Trade compliance obligations.

   As per Ontario Ministry of the Environment and Climate Change's ("MOECC") "Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions - Effective November 2017," standard quantification method (SQM) ON.400 Natural Gas Distribution, CO_2 emissions are calculated based on the volumes of natural gas distributed, adjusted for deliveries to other distributors or exports, net deliveries to storage and deliveries to capped participants.

   Additionally, any natural gas derived from biomass is excluded from the volumes previously outlined above. As a result, under SQM ON.400, Union Gas has no compliance obligations due to CO_2 emissions from RNG. This methodology is supported by the Intergovernmental Panel on Climate Change (IPCC), which states, in Chapter 8: Anthropogenic and Natural Radiative Forcing of Climate Change 2013: The Physical Science Basis, Contribution of Working Group I to the Fifth Assessment Report of the IPCC, that "emissions of CO_2 from the combustion of biomass for energy in national inventories are currently assumed to have no net RF [radiative forcing], based on the assumption that these emissions are compensated by biomass regrowth" (IPCC WG1 Fifth Assessment Report, Chapter 8, p.714, dated 2013).

b) The reference to “the use of RNG does not release any additional carbon into the atmosphere” refers to the fact that emissions of CO_2 from combustion of biomass are considered CO_2 neutral. In other words, the CO_2 from combustion of biomass is balanced by the CO_2 removed from the atmosphere by biomass growth. This is consistent with part a) above.

UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Reference: Exhibit 3, Tab 4, Page 18

Preamble: We would like to understand better the priority being placed upon RNG versus other abatement activities. The evidence states:" *When the specific sources of biogas (particularly those that are in close proximity to existing pipeline infrastructure) and the cost of upgrading the biogas are considered, the anticipated cost for RNG is typically higher than the combined cost of carbon and the cost of conventional natural gas today and for the foreseeable future. The OEB-issued MACC also identified that RNG is not a cost-effective measure relative to the cost of carbon. In order to advance the adoption of RNG in support of provincial GHG emission targets and incent the development of the RNG market, additional provincial funding and MOECC program support is required.* "

Question:

If RNG is not cost effective, why's there priority on this project when other projects of higher abatement efficacy may not be funded if government funding is provided to RNG as a priority?

Response:

Union has no basis to assume that projects of higher abatement efficacy may not be funded if government funding is provided to RNG. Please see the response at Exhibit B.Staff.1 e).

UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Reference: Exhibit 3, Tab 4, Page 19

Preamble: We would like to understand better the nature of communications and information provided to the MOECC by the utilities. The evidence states: *"Since 2016, Union and EGD have worked collaboratively to seek such support from the MOECC for an RNG program. Earlier in 2017, Union and EGD developed an RNG proposal for the province that will achieve the market objectives of the province by providing a mechanism to facilitate RNG procurement funding and cost recovery"*

Question:

Please provide copies of all presentations made and communications sent to MOECC.

Response:

Please see the response at Exhibit B.Energy Probe.2 f).

UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Reference: Exhibit 3, Tab 4, Page 19

Preamble: We would like to understand better the nature of communications and information provided to the MOECC by the utilities. The evidence states: *"Since 2016, Union and EGD have worked collaboratively to seek such support from the MOECC for an RNG program. Earlier in 2017, Union and EGD developed an RNG proposal for the province that will achieve the market objectives of the province by providing a mechanism to facilitate RNG procurement funding and cost recovery"*

Question:

Please provide copies of all presentations made and communications sent to Union Gas or Enbridge executive to obtain approvals to propose the resulting mechanism.

Response:

No presentations were made to Union executive to obtain approvals. Union executives received the same presentation materials and documents included in Union's response at Exhibit B.Energy Probe.2 f), and gave verbal approvals to proceed with the proposal.

UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

Reference: Exhibit 3, Tab 4, Page 19

Preamble: As Union pursues the development of this market, we would like to understand better the ratepayer protections that Union would be providing. The evidence states: "*As a result, Union expects to enter into fixed price RNG procurement contracts with terms up to 10 years in duration, subject to provincial funding.*"

Question:
Please provide the mechanisms that Union will put in place to ensure that ratepayers are held harmless all costs associated with the contracting for and the development of capabilities to deliver RNG to the pipeline prior to assurance of provincial government funding to cover those costs.

Response:

Please see the response at Exhibit B.Staff.6 d).

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 1, page 6

Question:
Union has requested approval to proceed with its RNG procurement proposal by the end of January, 2018. Please provide the impacts on the proposal if OEB approval is not received until the end of February, March, or April.

Response:

Please see the response to Exhibit B.Staff.7 a).

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 3, Tab 1, page 3

Preamble: The evidence indicates Union has been actively pursuing RNG for 2018, working jointly with EGD, the Ministry of Energy and the MOECC to advance this initiative.

Question:
Please provide all documents in Union's possession associated with this joint effort.

Response:

Please see the response at Exhibit B.Energy Probe.2 f).

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 3, Tab 1, page 6

Question:
What is the current status of government funding for RNG?

Response:

The proposal for funding RNG is currently being reviewed by the province.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 3, Tab 1, pages 21-22

Question:
Given the uncertainties noted in the evidence, how has Union factored this into the cost, production level and timing of its RNG proposal?

Response:

Cost and production levels of RNG will be discovered through the RFP process.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 3, Tab 4, page 2

Question:

a) Please confirm that if Union does not receive government funding it will not proceed with the RNG proposal as currently filed. If this cannot be confirmed, please explain fully.
b) Under what circumstances would Union proceed with its current RNG proposal, or some alternative to that proposal, if the level of government funding is less than that included in Union's current proposal? Please explain fully.

Response:

a) Confirmed.

b) Union would proceed if the funding level was more or less than expected and procure as much RNG as there is funding to support.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 3, Tab 4, page 18

Question:

a) What requirements will Union put in place to ensure that the RNG injected into the distribution system will be of similar quality to fossil natural gas?
b) Is the heat content of RNG the same as conventional natural gas? If not, is it higher or lower?
c) If the heat content of RNG is not the same as conventional natural gas, how will Union address the potential impacts on customers that are located along lines close to injection points of RNG?
d) Will Union require RNG to meet the same quality requirements as required from local natural gas producers in Ontario? Please explain fully any differences.

Response:

a) All RNG production injected into Union's distribution system will be subject to the same quality requirements that are applied to existing conventional natural gas production. These requirements are outlined in Article II of Union's M13 General Terms & Conditions, included as Attachment 1. Union will require that all RNG producer stations include gas quality monitoring equipment such that quality attributes can be monitored on a real time basis through Union's SCADA system.

b) – c) Heat content of natural gas delivered to Union's system is covered within the quality requirements outlined in part a) above. RNG heat content must conform to these same quality requirements to ensure the quality of gas delivered to customers located in the vicinity of RNG production. While the heat content of RNG is expected to be lower than that of conventional natural gas, it will still conform to Union's gas quality requirements.

d) See part a) above.

RATE M13
GENERAL TERMS & CONDITIONS

I. DEFINITIONS

Except where the context expressly requires or states another meaning, the following terms, when used in these General Terms & Conditions and in any contract into which these General Terms & Conditions are incorporated, shall be construed to have the following meanings:

"**Aid to Construction**" shall include any and all costs, expenses, amounts, damages, obligations, or other liabilities (whether of a capital or operating nature, and whether incurred before or after the date of the Contract) actually paid by Union (including amounts paid to affiliates for services rendered in accordance with the Affiliate Relationships Code as established by the OEB) in connection with or in respect of satisfying the conditions precedent set out in Article XXI herein (including without limitation the cost of construction, installation and connection of any required meter station as described in Article IX, Section 6, the obtaining of all governmental, regulatory and other third party approvals, and the obtaining of rights of way) whether resulting from Union's negligence or not, except for any costs that have arisen from the gross negligence, fraud, or wilful misconduct of Union;

"**Average Local Producer Heat**" ("**ALPH**") shall mean the heat content value as set by Union, and shall be determined by volumetrically averaging the gross heat content of all produced gas delivered to the Union system by Ontario Local Producers. The ALPH shall be expressed in $GJ/10^3m^3$ and may be adjusted from time to time by Union;

"**Business Day**" shall mean any day, other than Saturday, Sunday or any days on which national banks in the Province of Ontario are authorized to close;

"**Contract**" shall refer to the Contract to which these General Terms & Conditions shall apply, and into which they are incorporated;

"**Contract Year**" shall mean a period of three hundred and sixty-five (365) consecutive days; provided however, that any such period which contains a date of February 29 shall consist of three hundred and sixty-six (366) consecutive days, commencing on November 1 of each year; except for the first Contract Year which shall commence on the Commencement Date and end on the first October 31 that follows such date;

"**cricondentherm hydrocarbon dewpoint**" shall mean the highest hydrocarbon dewpoint temperature on the phase envelope;

"**cubic metre**" shall mean the volume of gas which occupies one cubic metre when such gas is at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute;

"**Dawn Quantity**" shall mean the total daily quantity of gas in GJ delivered at Dawn (Facilities), which is equal to the total energy of all gas supplied daily to Union at the Receipt Point(s). The Dawn Quantity shall be calculated utilizing the following factor equation: Dawn Quantity = Produced Volume x ALPH;

"**Day**" shall mean a period of twenty-four (24) consecutive hours beginning at 10:00 a.m. Eastern Clock Time. The reference date for any Day shall be the calendar date upon which the twenty-four (24) hour period shall commence;

"**Delivery Point**" shall mean the point where Union shall deliver the Dawn Quantity and/or Market Quantity to Shipper and as further defined in Schedule 1 of the Contract;

"**Distribution Demand**" shall mean the varying demand for the supply of gas, as determined by Union, on Union's pipeline and distribution system for users of gas who are supplied or delivered gas by Union's pipeline and distribution system;

"**Eastern Clock Time**" shall mean the local clock time in the Eastern Time Zone on any Day;

"**firm**" shall mean service not subject to curtailment or interruption except under Articles XI, XII and XVIII herein;

"**Firm Daily Variability Demand**" shall mean the established quantity set forth in Schedule 2 of the Contract, which is the permitted difference between the Dawn Quantity and the Market Quantity;

"**gas**" shall mean gas as defined in the Ontario Energy Board Act, 1998, S.O. 1998, c.15, Sch. B, as amended, supplemented or re-enacted from time to time;

"**gross heating value**" shall mean the total heat expressed in megajoules per cubic metre (MJ/m^3) produced by the complete combustion at constant pressure of one (1) cubic metre of gas with air, with the gas free of water vapour and the temperature of the gas, air and products of combustion at standard temperature and all water formed by the combustion reaction condensed to the liquid state;

"**hydrocarbon dewpoint**" shall mean temperature at a specific pressure where hydrocarbon vapour condensation begins;

"**Interruptible Service HUB Contract**" shall mean a contract between Shipper and Union under which Union provides interruptible HUB service;

"**Interconnecting Pipeline**" shall mean a pipeline that directly connects to the Union pipeline and distribution system;

"**joule**" (J) shall mean the work done when the point of application of a force of one (1) newton is displaced a distance of one (1) metre in the direction of the force. The term "**megajoule**" (MJ) shall mean 1,000,000 joules. The term "**gigajoule**" (GJ) shall mean 1,000,000,000 joules;

"**m^3**" shall mean cubic metre of gas and "**10^3m^3**" shall mean 1,000 cubic metres of gas;

"**MAOP"** shall mean the maximum allowable operating pressure of Union's pipeline and distribution system and as further defined in Schedule 1 of the Contract;

"**Market Quantity**" shall mean the daily quantity in GJ nominated for Name Change Service that Day by Shipper at Dawn (Facilities);

"**Maximum Daily Quantity**" shall mean the maximum quantity of gas Shipper may deliver to Union at a Receipt Point on any Day, as further defined in Schedule 1;

"**Month**" shall mean the period beginning at 10:00 a.m. Eastern Clock Time on the first day of a calendar month and ending at 10:00 a.m. Eastern Clock Time on the first day of the following calendar month;

"**Name Change Service**" shall mean an interruptible administrative service whereby Union acknowledges for Shipper a change in title of a gas quantity from Shipper to a third party at the Delivery Point;

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

"**pascal**" "**(Pa)**" shall mean the pressure produced when a force of one (1) newton is applied to an area of one (1) square metre. The term "**kilopascal**" "**(kPa)"** shall mean 1,000 pascals;

"**Produced Volume**" shall mean the aggregate of all actual volumes of gas in 10^3m^3, delivered by Shipper to Union at all Receipt Points on any Day;

"**Producer Balancing Account**" shall mean the gas balance held by Union for Shipper, or owed by Shipper to Union, at the Delivery Point. Where the Producer Balancing Account is zero or a positive number, the account is in a credit position, and where the Producer Balancing Account is less than zero, the account is in a debit position;

"**Producer Balancing Service**" shall mean a Service whereby Union either calculates a credit or debit to the Producer Balancing Account by subtracting the Market Quantity from the Dawn Quantity. Where such amount is greater than zero, Union will credit the Producer Balancing Account, or where such amount is less than zero, Union will debit the Producer Balancing Account. This Service shall be performed on a retroactive basis on the terms and conditions contained in Schedule 2 of the Contract, as may be revised from time to time by Union;

"Receipt Point" shall mean the point(s) where Union shall receive gas from Shipper;

"**Sales Agreement**" shall mean the Ontario Gas Purchase Agreement(s) entered into between Shipper and Union;

"**Shipper**" shall have the meaning as defined in the Contract, and shall also include Shipper's agent(s);

"**specific gravity**" shall mean density of the gas divided by density of air, with both at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute;

"**System Capacity**" shall mean the volumetric capacity that exists from time to time within Union's pipeline and distribution system which determines Union's ability to accept volumes of gas into Union's pipeline and distribution system hereunder. System Capacity shall be determined by Union and such determination, in addition to the physical characteristics of Union's pipeline and distribution system Distribution Demand, shall also include consideration of Union's local Distribution Demand, Union's total system Distribution Demand, availability of Union's gas storage capacity, and other gas being purchased and/or delivered into Union's pipeline and distribution system;

"**Taxes**" shall mean any tax (other than tax on income or tax on property), duty, royalty, levy, license, fee or charge not included in the charges and rates as per the applicable rate schedule (including but not limited to charges under any form of cap and trade, carbon tax, or similar system) and that is levied, assessed or made by any governmental authority on the gas itself, or the act, right, or privilege of producing, severing, gathering, storing, transporting, handling, selling or delivering gas under the Contract;

"**Wobbe Number**" shall mean gross heating value of the gas divided by the square root of its specific gravity.

II. GAS QUALITY

1. Natural Gas: The minimum gross heating value of the gas delivered to/by Union hereunder, shall be thirty-six (36) megajoules per cubic metre. The maximum gross heating value of the gas delivered to/by Union hereunder shall be forty point two (40.2) megajoules per cubic metre. The gas to be delivered hereunder to Union may be a commingled supply from Shipper's gas sources of supply. The gas to be delivered by Union may be a commingled supply from Union's sources of gas supply; provided, however, that helium, natural gasoline, butane, propane and other hydrocarbons, except methane, may be removed prior to delivery to Shipper. Further, Union may subject, or permit the subjection of, the gas to compression, dehydration, cooling, cleaning and other processes.

2. Freedom from objectionable matter: The gas to be delivered to Union at the Receipt Point(s) hereunder,

   a. shall be commercially free from bacteria, sand, dust, gums, crude oils, lubricating oils, liquids, chemicals or compounds used in the production, treatment, compression or dehydration of the gas or any other objectionable substance in sufficient quantity so as to render the gas toxic, unmerchantable or cause injury to, or interference with, the proper operation of the lines, regulators, meters or other appliances through which it flows,

   b. shall not contain more than seven (7) milligrams of hydrogen sulphide per cubic metre of gas, nor more than one hundred (100) milligrams of total sulphur per cubic metre of gas,

   c. shall not contain more than five (5) milligrams of mercaptan sulphur per cubic metre of gas,

   d. shall not contain more than two point zero (2.0) molar percent by volume of carbon dioxide in the gas,

   e. shall not contain more than zero point four (0.4) molar percent by volume of oxygen in the gas,

   f. shall not contain more than zero point five (0.5) molar percent by volume of carbon monoxide in the gas,

   g. shall not contain more than four point zero (4.0) molar percent by volume of hydrogen in the gas,

   h. shall not contain more than sixty-five (65) milligrams of water vapour per cubic metre of gas,

   i. shall not have a cricondentherm hydrocarbon dewpoint exceeding minus eight (-8) degrees Celsius,

   j. shall have Wobbe Number from forty seven point fifty (47.50) megajoules per cubic metre of gas to fifty one point forty six (51.46) megajoules per cubic metre of gas, maximum of one point five (1.5) mole percent by volume of butane plus (C4+) in the gas, and maximum of four point zero (4.0) mole percent by volume of total inerts in the gas in order to be interchangeable with other Interconnecting Pipeline gas,

k. shall not exceed forty-three degrees Celsius (43ºC), and,

l. shall not be odourized by Shipper.

3. Non-conforming Gas:

a. In the event that the quality of the gas does not conform or if Union, acting reasonably, suspects the quality of the gas may not conform to the specifications herein, then Shipper shall, if so directed by Union acting reasonably, forthwith carry out, at Shipper's cost, whatever field testing of the gas quality as may be required to ensure that the quality requirements set out herein are met, and to provide Union with a certified copy of such tests. If Shipper does not carry out such tests forthwith, Union may conduct such test and Shipper shall reimburse Union for all costs incurred by Union for such testing.

b. If Shipper's gas fails at any time to conform to the requirements of this Article II, Union, in addition to its other remedies, may refuse to accept delivery of gas at the Receipt Points hereunder until such deficiency has been remedied by Shipper. Each Party agrees to notify the other verbally, followed by written notification, of any such deficiency of quality.

4. Quality of Gas Received: The quality of the gas to be received by Union at the Receipt Point(s) hereunder is to be of a merchantable quality and in accordance with the quality standards as set out by Union in this Article II, but, Union will use reasonable efforts to accept gas of a quality that may deviate from the quality standards set out therein.

5. Quality of Gas at Dawn: The quality of the gas to be delivered to Union at Dawn (Facilities) or the gas to be delivered by Union to Shipper at Dawn (Facilities) hereunder is to be of a merchantable quality and in accordance with the quality standards and measurement standards as set out by Union in this Article II, except that total sulphur limit shall be not more than four hundred and sixty (460) milligrams per cubic metre of gas. In addition to any other right or remedy of a party, each party shall be entitled to refuse to accept delivery of any gas which does not conform to any of the specifications set out in this Article II.

III. MEASUREMENTS

1. Service Unit: The unit of the gas delivered to Union shall be a quantity of 10^3m^3. The unit of gas delivered by Union shall be a megajoule, a gigajoule, a cubic metre (m^3) or one thousand cubic metres (10^3m^3) at Union's discretion.

2. Determination of Volume and Energy:

a. The volume and energy amounts determined under the Contract shall be determined in accordance with the Electricity and Gas Inspection Act (Canada), RSC 1985, c E-4- (the "**Act**") and the Electricity and Gas Inspection Regulations, SOR 86/131 (the "**Regulations**"), and any documents issued under the authority of the Act and Regulations and any amendments thereto.

b. The supercompressibility factor shall be determined in accordance with either the "**Manual for Determination of Supercompressibility Factors for Natural Gas**" (PAR Project NX-19) published in 1962 or with American Gas Association Transmission Measurement Committee Report No. 8, Nov. 1992, at Union's discretion, all as amended from time to time.

c. The volume and/or energy of the gas delivered to/by Union hereunder shall be determined by the measurement equipment designated in Article VII herein.

IV. RECEIPT POINT AND DELIVERY POINT

The point(s) of receipt and point of delivery for all gas to be covered hereunder shall be on the outlet side of the measuring stations located at or near the point or points of connection specified in Schedule 1 of the Contract, where possession of the gas changes from one party to the other.

V. POSSESSION OF AND RESPONSIBILITY FOR GAS

1. Possession of Gas: Union accepts no responsibility for any gas prior to such gas being delivered to Union at the Receipt Point or after its delivery by Union at the Delivery Point. As between the parties hereto, Union shall be deemed to be in control and possession of and responsible for all such gas from the time that such gas enters Union's system until such gas is delivered to Shipper.

2. Liability: Shipper agrees that Union is not a common carrier and is not an insurer of Shipper's gas, and that Union shall not be liable to Shipper or any third party for loss of gas in Union's possession, except to the extent such loss is caused entirely by Union's negligence or wilful misconduct.

VI. FACILITIES ON SHIPPER'S PROPERTY

1. Meter Station: Union shall provide, at the Receipt Point(s), according to the terms hereunder, the meter station required to receive and measure the Produced Volume of gas received by Union from Shipper. Shipper agrees, if requested by Union, to provide Union with sufficient detailed information regarding Shipper's current and expected operations in order to aid Union in Union's design of the meter station.

2. Union Obligations: Pursuant to Article VI. Section 1 herein, Union shall purchase, install and maintain, at the Receipt Point(s):

   a. a meter and any associated recording gauges as are necessary; and,

   b. a suitable gas odourizing injection facility where Union deems such facility to be necessary.

3. Union Equipment: All equipment installed by Union at the Receipt Point(s) shall remain the property of Union at all times, notwithstanding the fact that it may be affixed to Shipper's property. Union shall be entitled to remove said equipment at any time within a period of sixty (60) days from any termination or expiry of the Contract. Shipper shall take all necessary steps to ensure Union may enter onto the Receipt Point(s) to remove such equipment for a period of sixty (60) days after termination or expiry of the Contract or the Sales Agreement.

4. Shipper Obligations: Upon Union's request Shipper shall, at Shipper's own cost and expense:

   a. obtain a registered lease or freehold ownership at the Receipt Point(s) sufficient to provide Union with free uninterrupted access to, from, under and above the Receipt Point(s), for a term (and extended terms) identical to the Contract, plus sixty (60) days, and shall provide Union with a bona fide copy of such lease agreement prior to Union commencing the construction of the meter station;

   b. furnish, install, set, and maintain suitable pressure and volume control equipment and such additional equipment as required on Shipper's delivery system, to protect against the overpressuring of Union's facilities, and to limit the daily flow of gas to the corresponding Maximum Daily Quantity applicable to the Receipt Point(s);

   c. supply, install and maintain a gravel or cut stone covering on each Receipt Point and shall maintain such Receipt Point(s) in a safe and workmanlike manner; and,

   d. install and maintain a fence satisfactory to Union around the perimeter of each Receipt Point which will adequately secure and protect Union's equipment therein.

5. Maintenance Costs: Shipper shall within thirty (30) days of the delivery of an invoice by Union, reimburse Union for any actual costs reasonably incurred by Union for any repair, replacement, relocation, or upgrading of any meter station

requested by Shipper, or as required by law, or by duly constituted regulatory body, or through good engineering practice. Union shall be responsible for any costs incurred by Union to correct an error made by Union.

VII. MEASURING EQUIPMENT

1. Metering by Union: Union will install and operate meters and related equipment as required and in accordance with the Act and Regulations referenced in Article III herein.

2. Metering by Others: In the event that all or any gas received or delivered hereunder is measured by a meter that is owned and operated by an upstream or downstream transporter (the "**Transporter**") whose facilities may or may not interconnect with Union's, then Union and Shipper agree to accept that metering for the purpose of determining the volume and energy of gas received or delivered on behalf of the Shipper. The standard of measurement and tests for the gas delivered to/by Union pursuant to this Article VII, Section 2 shall be in accordance with the general terms and conditions as incorporated in that Transporter's gas tariff as approved by Transporter's regulatory body.

3. Check Measuring Equipment: Shipper may install, maintain and operate, at the Receipt Point, at its own expense, such check measuring equipment as desired, provided that such equipment shall be so installed as not to interfere with the operation of Union's measuring equipment at or near the Receipt Point, and shall be installed, maintained and operated in conformity with the same standards and specifications applicable to Union's metering facilities.

4. Calibration and Test of Measuring Equipment: The accuracy of Union's measuring equipment shall be verified by Union at reasonable intervals, and if requested, in the presence of representatives of Shipper, but Union shall not be required to verify the accuracy of such equipment more frequently than once in any thirty (30) day period. In the event either party notifies the other that it desires a special test of any measuring equipment, the parties shall co-operate to secure a prompt verification of the accuracy of such equipment. The expense of any such special test, if called for by Shipper, shall be borne by Shipper if the measuring equipment tested is found to be in error by not more than two per cent (2%). If, upon test, any measuring equipment is found to be in error by not more than two per cent (2%), previous recordings of such equipment shall be considered accurate in computing receipts of gas, but such equipment shall be adjusted at once to record as near to absolute accuracy as possible. If the test conducted shows a percentage of inaccuracy greater than two percent (2%), the financial adjustment, if any, shall be calculated in accordance with the Act and Regulations, as may be amended from time to time and in accordance with any successor statutes and regulations.

5. Preservation of Metering Records: Union and Shipper shall each preserve for a period of at least six (6) years all test data, and other relevant records.

VIII. BILLING

1. Monthly Billing Date: Union shall render bills on or before the tenth (10th) day of each month for all Services furnished during the preceding Month. Such charges may be based on estimated quantities, if actual quantities are unavailable in time to prepare the billing. Union shall provide, in a succeeding Month's billing, an adjustment based on any difference between actual quantities and estimated quantities, without any interest charge. If presentation of a bill to Shipper is delayed after the tenth (10th) day of the month, then the time of payment shall be extended accordingly, unless Shipper is responsible for such delay.

2. Right of Examination: Both Union and Shipper shall have the right to examine at any reasonable time the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, chart or computation made under or pursuant to the provisions of the Contract.

3. Amendment of Statements: For the purpose of completing a final determination of the actual quantities of gas handled in any of the Services to Shipper, the parties shall have the right to amend their statement for a period equal to the time during which the companies, that transport the gas contemplated herein for Union and Shipper, retain the right to amend their statements, which period shall not exceed three (3) years from the date of termination of the Contract.

IX. PAYMENTS

1. <u>Monthly Payments:</u> Shipper shall pay the invoiced amount directly into Union's bank account as directed on the invoice on or before the twentieth (20th) day of each month. If the payment date is not a Business Day, then payment must be received in Union's account on the first Business Day preceding the twentieth (20th) day of the month.

2. <u>Remedies for Non-payment:</u> Should Shipper fail to pay all of the amount of any bill as herein provided when such amount is due,

   a. Shipper shall pay to Union interest on the unpaid portion of the bill accruing at a rate per annum equal to the minimum commercial lending rate of Union's principal banker in effect from time to time from the due date until the date of payment; and,

   b. If such failure to pay continues for thirty (30) days after payment is due, Union, in addition to any other remedy it may have under the Contract, may suspend Services until such amount is paid. Notwithstanding such suspension, all demand charges shall continue to accrue hereunder as if such suspension were not in place.

   If Shipper in good faith disputes the amount of any such bill or part thereof Shipper shall pay to Union such amounts as it concedes to be correct. At any time thereafter, within twenty (20) days of a demand made by Union, Shipper shall furnish financial assurances satisfactory to Union, guaranteeing payment to Union of the amount ultimately found due upon such bill after a final determination. Such a final determination may be reached either by agreement, arbitration decision or judgement of the courts, as may be the case. Union shall not be entitled to suspend Services because of such non-payment unless and until default occurs in the conditions of such financial assurances or default occurs in payment of any other amount due to Union hereunder.

   Notwithstanding the foregoing, Shipper is not relieved from the obligation to continue its deliveries of gas to Union under the terms of any agreement, where Shipper has contracted to deliver specified quantities of gas to Union.

3. <u>Billing Adjustments:</u> If it shall be found that at any time or times Shipper has been overcharged or undercharged in any form whatsoever under the provisions of the Contract and Shipper shall have actually paid the bills containing such overcharge or undercharge, Union shall refund the amount of any such overcharge and interest shall accrue from and including the first day of such overcharge as paid to the date of refund and shall be calculated but not compounded at a rate per annum determined each day during the calculation period to be equal to the minimum commercial lending rate of Union's principal banker, and the Shipper shall pay the amount of any such undercharge, but without interest. In the event Union renders a bill to Shipper based upon measurement estimates, the required adjustment to reflect actual measurement shall be made on the bill next following the determination of such actual measurement, without any charge of interest. In the event an error is discovered in the amount billed in any statement rendered by Union, such error shall be adjusted by Union. Such overcharge, undercharge or error shall be adjusted by Union on the bill next following its determination (where the term "**bill next following**" shall mean a bill rendered at least fourteen (14) days after the day of its determination), provided that claim therefore shall have been made within three (3) years from the date of the incorrect billing. In the event any refund is issued with Shipper's bill, the aforesaid date of refund shall be deemed to be the date of the issue of bill.

4. <u>Taxes:</u> In addition to the charges and rates as per the applicable rate schedules and price schedules, Shipper shall pay all Taxes which are imposed currently or subsequent to the execution of the Contract by any legal authority having jurisdiction and any amount in lieu of such Taxes paid or payable by Union.

5. <u>Set Off:</u> If either party shall, at any time, be in arrears under any of its payment obligations to the other party under the Contract, then the party not in arrears shall be entitled to reduce the amount payable by it to the other party in arrears under the Contract, or any other contract, by an amount equal to the amount of such arrears or other indebtedness to the other party. In addition to the foregoing remedy, Union may, upon forty-eight (48) hours verbal notice, to be followed by written notice, take possession of any or all of Shipper's gas under the Contract, which shall be deemed to have been assigned to Union, to reduce such arrears or other indebtedness to Union.

6. <u>Station and Connection Costs:</u> In the event that a meter station must be constructed and/or installed in order to give effect to the Contract, Shipper agrees to pay Union for a portion, as determined by Union, of Union's actual cost, as hereinafter defined, for constructing and installing such station. Shipper also agrees to pay the actual costs to connect such station to Union's pipeline and distribution system. Union shall advise Shipper as to the need for a meter station and shall provide Shipper with an estimate of the Aid to Construction. Such Aid to Construction shall include the costs of all pipe, fittings and materials, third party labour costs and Union's direct labour, labour saving devices, vehicles and

mobile equipment, but shall exclude the purchase costs of gas pressure control equipment and gas meters installed by Union.

X. ARBITRATION

If and when any dispute, difference or question shall arise between the parties hereto touching the Contract or anything herein contained, or the construction hereof, or the rights, duties or liabilities of the parties in relation to any matter hereunder, the matter in dispute shall be submitted and referred to arbitration within ten (10) days after written request of either party. Upon such request each party shall appoint an arbitrator, and the two so appointed shall appoint a third. A majority decision of the arbitrators shall be final and binding upon both parties. In all other respects the provisions of the Arbitration Act, 1991, or any act passed in amendment thereof or substitution therefore, shall apply to each such submission. Operations under the Contract shall continue, without prejudice, during any such arbitration and the costs attributable to such arbitration shall be shared equally by the parties hereto.

XI. FORCE MAJEURE

1. Definition: The term "**force majeure**" as used herein shall mean acts of God, strikes, lockouts or any other industrial disturbance, acts of the public enemy, sabotage, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, freezing of wells or lines of pipe, inability to obtain materials, supplies, permits or labour, any laws, orders, rules, regulations, acts or restraints of any governmental body or authority (civil or military), any act or omission that is excused by any event or occurrence of the character herein defined as constituting force majeure, any act or omission by parties not controlled by the party having the difficulty and any other similar cases not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome.

2. Notice: In the event that either the Shipper or Union is rendered unable, in whole or in part, by force majeure, to perform or comply with any obligation or condition of the Contract, such party shall give notice and full particulars of such force majeure in writing delivered by hand, fax or other direct written electronic means to the other party as soon as possible after the occurrence of the cause relied on and subject to the provision of this Article.

3. Exclusions: Neither party shall be entitled to the benefit of the provisions of force majeure hereunder if any or all of the following circumstances prevail: the failure resulting in a condition of force majeure was caused by the negligence of the party claiming suspension; the failure was caused by the party claiming suspension where such party failed to remedy the condition by making all reasonable efforts (short of litigation, if such remedy would require litigation); the party claiming suspension failed to resume the performance of such condition obligations with reasonable dispatch; the failure was caused by lack of funds; the party claiming suspension did not, as soon as possible after determining, or within a period within which it should acting reasonably have determined, that the occurrence was in the nature of force majeure and would affect its ability to observe or perform any of its conditions or obligations under the Contract, give to the other party the notice required hereunder.

4. Notice of Remedy: The party claiming suspension shall likewise give notice as soon as possible after the force majeure condition is remedied, to the extent that the same has been remedied, and that such party has resumed or is then in a position to resume the performance of the obligations and conditions of the Contract.

5. Obligation to Perform: An event of force majeure on Union's system will excuse the failure to deliver gas by Union or the failure to accept gas by Union hereunder, and both parties shall be excused from performance of their obligations hereunder, except for payment obligations, to the extent of and for the duration of the force majeure.

6. Upstream or Downstream Force Majeure: An event of force majeure upstream or downstream of Union's system shall not relieve Shipper of any payment obligations.

7. Delay of Services: Despite Article XI herein, if Union is prevented, by reason of an event of force majeure on Union's system from delivering gas on the Day or Days upon which Union has accepted gas from Shipper, Union shall thereafter make all reasonable efforts to deliver such quantities as soon as practicable and on such Day or Days as are agreed to

by Shipper and Union. If Union accepts such gas on this basis, Shipper shall not receive any demand charge relief as contemplated under Article XI herein.

8. Firm Daily Variability Demand Charge Relief: Despite Article XI herein, if on any Day Union fails to accept gas from Shipper by reason of an event of force majeure on Union's system and fails to deliver the quantity of gas nominated hereunder by Shipper up to the Firm Daily Variability Demand for that Contract, then for that Day the Monthly charge shall be reduced by an amount equal to the applicable Firm Daily Variability Demand Rate, as defined in this paragraph, multiplied by the difference between the quantity of gas actually delivered by Union during such Day and the quantity of gas which Shipper in good faith nominated on such Day. The term "**Firm Daily Variability Demand Rate**" shall mean the monthly Firm Daily Variability Demand charge as provided in Schedule 2 of the Contract, divided by the number of days in the month for which such rate is being calculated.

XII. DEFAULT AND TERMINATION

In case of the breach or non-observance or non-performance on the part of either party hereto of any covenant, proviso, condition, restriction or stipulation contained in the Contract (but not including herein failure to take or make delivery in whole or in part of the gas delivered to/by Union hereunder occasioned by any of the reasons provided for in Article XI herein) which has not been waived by the other party, then and in every such case and as often as the same may happen, the non-defaulting party may give written notice to the defaulting party requiring it to remedy such default and in the event of the defaulting party failing to remedy the same within a period of thirty (30) days from receipt of such notice, the non-defaulting party may at its sole option declare the Contract to be terminated and thereupon the Contract shall be terminated and be null and void for all purposes other than and except as to any liability of the parties under the same incurred before and subsisting as of termination. The right hereby conferred upon each party shall be in addition to, and not in derogation of or in substitution for, any other right or remedy which the parties respectively at law or in equity shall or may possess.

In the event that the Contract is terminated pursuant to this Article XII, the parties hereto agree that they shall continue to be bound only by the terms and conditions set forth in the Contract but only for the purpose of determining the actual quantities in Shipper's Producer Balancing Account with such determination being subject to Article X. Such extended period of time shall not exceed one (1) year from the date of termination of the Contract.

XIII. AMENDMENT

Subject to Article XV herein and the ability of Union to amend the applicable rate schedules and price schedules, with the approval of the OEB (if required), no amendment or modification of the Contract shall be effective unless the same shall be in writing and signed by each of the Shipper and Union.

XIV. NON-WAIVER AND FUTURE DEFAULT

No waiver of any provision of the Contract shall be effective unless the same shall be in writing and signed by the party entitled to the benefit of such provision and then such waiver shall be effective only in the specific instance and for the specified purpose for which it was given. No failure on the part of Shipper or Union to exercise, and no course of dealing with respect to, and no delay in exercising, any right, power or remedy under the Contract shall operate as a waiver thereof.

XV. LAWS, REGULATIONS AND ORDERS

The Contract and the respective rights and obligations of the parties hereto are subject to all present and future valid laws, orders, rules and regulations of any competent legislative body, or duly constituted authority now or hereafter having jurisdiction and the Contract shall be varied and amended to comply with or conform to any valid order or direction of any board, tribunal or administrative agency which affects any of the provisions of the Contract.

XVI. RESERVED FOR FUTURE USE

N/A

XVII. RENEWALS

The Contract will continue in full force and effect beyond the Initial Term, automatically renewing for a period of one (1) year, and every one (1) year thereafter, subject to notice in writing by either party of termination at least three (3) months prior to the expiration thereof.

XVIII. SERVICE CURTAILMENT

1. Verbal Notice: Excepting instances of emergency, Shipper and Union agree to give at least twenty-four (24) hours verbal notice before a planned curtailment of receipt or delivery, shut-down or start-up.

2. Emergency: Shipper shall complete and maintain a plan which depicts all of the Shipper's gas production facilities including all emergency shut off valves and emergency equipment and provide a copy to Union upon Union's request. Shipper shall provide to Union the names and telephone numbers of those persons whom Union may contact in the event of an emergency situation arising within the Shipper's facilities.

3. Emergency Notice: In the event that Union is notified by a third party or if Union becomes aware of an emergency situation in which Shipper's gas production site, pipeline or associated equipment is involved, Union shall immediately notify Shipper or Shipper's representative of such emergency condition.

4. Right to Modify: Union shall have the right, at all times, to reconstruct or modify Union's pipeline and distribution system and the pressure carried therein, notwithstanding that such reconstruction or modification may reduce the System Capacity available to receive Shipper's gas, or Shipper's ability to deliver gas to Union. Should Union expect any such reconstruction or modification to reduce the delivery or receipt of gas by either party, Union will, where able, provide Shipper with six (6) months' notice or as much notice as is reasonably practical in the circumstances. Union shall use reasonable efforts to assist the Shipper in meeting its Market Quantity in these circumstances.

XIX. SHIPPER'S REPRESENTATIONS AND WARRANTIES

1. Shipper's Warranty: Shipper warrants that it will, if required, maintain, or have maintained on its behalf, all external approvals including the governmental, regulatory, import/export permits and other approvals or authorizations that are required from any federal, state or provincial authorities for the gas quantities to be handled under the Contract. Shipper further warrants that it shall maintain in effect the Facilitating Agreements.

2. Financial Representations: Shipper represents and warrants that the financial assurances (including the Initial Financial Assurances and Security), if any, shall remain in place throughout the term hereof unless Shipper and Union agree otherwise. Shipper shall notify Union in the event of any change to the financial assurances (including the Initial Financial Assurances and Security), if any, throughout the term hereof. Should Union have reasonable grounds to believe that Shipper will not be able to perform or continue to perform any of its obligations under the Contract for any reason (a "**Material Event**"), then Shipper shall within fourteen (14) days of receipt of written notice by Union, obtain and provide to Union a letter of credit or other security in the form and amount reasonably required by Union (the "**Security**"). In the event that Shipper does not provide to Union such Security, Union may deem a default in accordance with the provisions of Article XII herein.

   In the event that Shipper in good faith, reasonably believes that it should be entitled to reduce the amount of or value of the Security previously provided, it may request such a reduction from Union and to the extent that the Material Event has been mitigated or eliminated, Union shall return all or a portion of the Security to Shipper within fourteen (14) Business Days after receipt of the request.

3. Licence: Shipper represents and warrants to Union that Shipper possesses a licence to produce gas in the Province of Ontario.

XX. MISCELLANEOUS PROVISIONS

1. Assignment: Shipper may assign the Contract to a third party ("**Assignee**"), up to the Maximum Daily Quantity, (the "**Capacity Assigned**"). Such assignment shall require the prior written consent of Union and release of obligations by Union for the Capacity Assigned from the date of assignment. Such consent and release shall not be unreasonably withheld and shall be conditional upon the Assignee providing, amongst other things, financial assurances as per Article XXI herein. Any such assignment will be for the full rights, obligations and remaining term of the Contract as relates to the Capacity Assigned.

2. Title to Gas: Shipper represents and warrants to Union that Shipper shall have good and marketable title to, or legal authority to deliver to Union, all gas delivered to Union hereunder. Furthermore, Shipper hereby agrees to indemnify and save Union harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses arising from or out of claims of any or all third parties to such gas or on account of Taxes, or other charges thereon.

XXI. PRECONDITIONS TO SERVICES

1. Union Conditions: The obligations of Union to provide Services hereunder are subject to the following conditions precedent, which are for the sole benefit of Union and which may be waived or extended in whole or in part in the manner provided in the Contract:

   a. Union shall have obtained, in form and substance satisfactory to Union, and all conditions shall have been satisfied under, all governmental, regulatory and other third party approvals, consents, orders and authorizations, that are required to provide the Services; and,

   b. Union shall have obtained all internal approvals that are necessary or appropriate to provide the Services; and,

   c. Union shall have received from Shipper the requisite financial assurances reasonably necessary to ensure Shipper's ability to honour the provisions of the Contract (the "**Initial Financial Assurances**"). The Initial Financial Assurances, if required, will be as determined solely by Union; and,

   d. Shipper and Union shall have entered into the Interruptible Service HUB Contract or equivalent (the "**Facilitating Agreement**") with Union; and,

   e. Union shall, where applicable, have obtained all internal and external approvals including the governmental, regulatory and other approvals or authorizations required to construct any facilities necessary to provide the Services hereunder, which approvals and authorizations, if granted upon conditions, shall be conditions satisfactory to Union; and,

   f. Union shall, where applicable, have completed and placed into service those facilities necessary to provide the Services hereunder; and,

   g. Further to Article IX Section 6 herein, Shipper shall pay to Union a payment ("**First Prepayment**") towards the Aid to Construction at the time of the execution of this Agreement. Shipper shall pay a payment prior to installation of the meter station ("**Second Prepayment**"). The foregoing payments are specified in the attached Schedule 1 for the first meter station ("**Receipt Point #1**") to be installed under the Contract. Payments for additional meter stations will be handled by written mutual agreement between the parties. Shipper shall pay Union the difference if the actual Aid to Construction is more than the Prepayments, within thirty (30) days of the delivery of an invoice from Union on which the actual costs for construction and installation of facilities are stated. Union shall pay Shipper the difference if the actual Aid to Construction is less than the Prepayments. In the event Shipper terminates this Agreement prior to Union incurring any costs related to the construction, installation or connection of the meter station, Shipper's Prepayments shall be returned to Seller, without interest, within fifteen (15) days notice to Union of such termination by Shipper. In the event Union has incurred costs, as set out herein, relative to the construction, installation or connection of the meter station prior to being notified by Shipper of Shipper's intention to terminate the Agreement, Union shall deduct such actual costs from Union's return of Shipper's Prepayments. "**Prepayments**" shall mean the sum of the First Prepayment and the Second

Prepayment.

2. Shipper Conditions: The obligations of Shipper hereunder are subject to the following conditions precedent, which are for the sole benefit of Shipper and which may be waived or extended in whole or in part in the manner provided in the Contract:

   a. Shipper shall, as required, have entered into the necessary contracts with Union and/or others to facilitate the Services contemplated herein, including contracts for upstream and downstream transportation, and shall specifically have an executed and valid Facilitating Agreement; and,

   b. Shipper shall have obtained, in form and substance satisfactory to Shipper, and all conditions shall have been satisfied under, all governmental, regulatory and other third party approvals, consents, orders and authorizations, that are required from federal, state, or provincial authorities for the gas quantities handled under the Contract; and,

   c. Shipper shall have obtained all internal approvals that are necessary or appropriate for the Shipper to execute the Contract; and,

   d. Shipper shall have cancelled or renegotiated its Sales Agreement, on terms satisfactory to Union, as applicable.

3. Satisfaction of Conditions: Union and Shipper shall each use due diligence and reasonable efforts to satisfy and fulfil the conditions precedent specified in this Article XXI Section 1 a, c, d, e, f, g, and Section 2 a, b, and d. Each party shall notify the other forthwith in writing of the satisfaction or waiver of each condition precedent for such party's benefit. If a party concludes that it will not be able to satisfy a condition precedent that is for its benefit, such party may, upon written notice to the other party, terminate the Contract and upon the giving of such notice, the Contract shall be of no further force and effect and each of the parties shall be released from all further obligations thereunder.

4. Non-Satisfaction of Conditions: If any of the conditions precedent in this Article XXI Section 1 c or Section 2 are not satisfied or waived by the party entitled to the benefit of that condition by the Conditions Date as such term is defined in the Contract, or if any of the Shipper payments required under the condition precedent in this Article XXI Section 1 g have not been paid as required in such section, then either party may, upon written notice to the other party, terminate the Contract and upon the giving of such notice, the Contract shall be of no further force and effect and each of the parties shall be released from all further obligations hereunder, provided that any rights or remedies that a party may have for breaches of the Contract prior to such termination and any liability a party may have incurred before such termination shall not thereby be released.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Exhibit 3, Tab 4, page 20

Preamble: The evidence states that Union would contract for provincial funding equal to the difference between the fixed price of RNG contracted with the producer, and the cost of conventional natural gas plus the avoided cost of carbon. The inclusion of the avoided cost of carbon is to recognize that customers would have incurred a carbon cost in the absence of RNG.

Question:

a) Will the contracted priced negotiated between Union and the RNG producer include the cost of carbon? In particular, in the example provided, does the $16/GJ long-term contracted price of RNG include the $0.85/GJ carbon price in 2018?
b) If the response to the above question is yes, does this mean that as the carbon price increases over the contractual term of the agreement, the net amount to the producer will decline?
c) Will Union be required to purchase cap and trade credits for both conventional natural gas and RNG, or only for conventional natural gas? Will there be any offsets to Union ratepayers to the carbon costs associated with the purchase of RNG? Please explain fully.

Response:

a) The contracted price between Union and the RNG producer is inclusive of the associated carbon abatement benefits of RNG. In the illustrative example, the $16/GJ is inclusive of the $0.85/GJ avoided cost of carbon.

b) – c) Please see the response at Exhibit B.Staff.6 d).

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 3, Tab 4, page 21

Question:
Will there be negotiations with the provincial government for each RNG procurement contract? If not, please explain how the forecast prices would be determined for multiple contracts that are negotiated at different times.

Response:

No, there will not be negotiations with the provincial government for each individual RNG procurement contract. The process used by Union to contract for RNG with producers will be shared with the province in support of receiving provincial funding and Union's proposed pricing methodology will be pre-approved by the OEB through this proceeding.

Forecast prices for natural gas will be determined by a transparent and reasonably accessible long term natural gas price forecast available at the time of contracting. In Union's illustrative example in Exhibit 3, Tab 4, page 21, Figure 3, an ICF natural gas price forecast for Dawn is used. Forecast prices for carbon will be determined by the most recent OEB mid-range Long Term Carbon Price Forecast available at the time of contracting.

RNG contracts that are negotiated at the same time will use the same forecasts for natural gas and carbon. As new or updated natural gas and carbon forecasts become available any new RNG contracts will be negotiated using the new forecasts.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 3, Tab 4, page 21

Preamble: Union's proposal is to use forecasts for traditional natural gas supplies and the forecasted cost of carbon as determined by the OEB LTCPF applicable at the time of contracting for conducting negotiations with the province.

Question:

a) Does this mean that the amount of provincial funding to be received by Union to subsidize the cost of RNG recovered from system gas ratepayers is fixed for the length of the contract and is based on the forecasts noted above?
b) Are system gas customers at risk for any actual cost variances from that forecast for the length of the RNG supply contracts, or will any variance between actual and forecast costs be included in the cap and trade charges?
c) Please explain how the net RNG costs will be recovered. Will they be included in the cost of gas and recovered only from system gas customers, or will they be included in the cap and trade costs and recovered through distribution rates rather than the cost of gas, or will the costs be split between the cost of gas and the cost of cap and trade? Please explain fully.

Response:

a)-c) Please see the response at Exhibit B.Staff.6 d).

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 3, Tab 4, page 21

Question:

a) Please confirm that the cost of cap and trade customer-related charges are recovered from all non-large final emitters and that the facility-related charges are recovered from all customers. If this cannot be confirmed, please explain.
b) If the RNG related costs are considered cap and trade costs, will the net cost related to RNG (cost less provincial funding) be recovered through the customer-related charge or the facility-related charge?
c) If the costs are recovered through the customer-related charge, please confirm that large final emitters would not pay any of the associated RNG costs.

Response:

a) Confirmed. For clarity, customer-related charges are recovered from customers for whom Union is required to fulfill Cap-and-Trade obligations and excludes large final emitters, voluntary participants and wholesale customers.

b) Please see the response at Exhibit B.Energy Probe.7 b).

c) Not confirmed. As described at Exhibit B.Energy Probe.7 b), the abatement cost associated with the RNG proposal will be attributed to both customer-related and facility-related obligations. The allocation of abatement costs to the facility-related compliance obligation will be recovered from all customers. The allocation of abatement costs to the customer-related compliance obligation will be recovered from customers for whom Union is required to fulfill Cap-and-Trade obligations and excludes large final emitters, voluntary participants and wholesale customers.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 3, Tab 4, page 22

Question:

a) What is the expected timing and frequency of the provincially funded portion of the RNG contracted price?
b) What is the expected timing and frequency of payment by Union of the RNG contracted price?
c) Based on the above responses, what is the impact on the working capital allowance with respect to the payment for RNG and the receipt of the provincially funded portion of the RNG cost relative to the purchase of conventional natural gas?

Response:

a) Please see the response at Exhibit B.Staff.4 c).

b) Similar to existing gas purchases, Union expects to pay RNG producers for supply delivered to its system in the month following delivery.

c) There is no impact to Union's working capital as a result of Union's RNG proposal. The government funding will not make up part of Union's working capital.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 3, Tab 4, pages 22-23

Preamble: The evidence states that customers would incur costs equal to the forecast cost of conventional natural gas plus the forecasted avoided cost of carbon.

Question:

a) What customers are being referred to by Union? Are they system gas customers, or all distribution customers? Please explain fully.
b) Please confirm that the customers are at risk for any difference between the forecasted cost of conventional natural gas and the actual cost, as well as any difference between the actual and forecasted avoided cost of carbon. If this cannot be confirmed, please explain fully.

Response:

a) and b) Please see the response at Exhibit B.Staff.6 d).

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 3, Tab 4, page 23

Question:

a) The evidence states that introducing RNG into the gas supply portfolio will reduce customer and facility emissions. Please explain how the use of RNG in place of conventional natural gas will reduce customer and facility emissions.
b) Is the carbon content of RNG lower than that of conventional natural gas?
c) What is the carbon content of RNG relative to that of conventional natural gas?

Response:

a)-c) Assuming that the energy content of the RNG and conventional natural gas is comparable, RNG methane produces carbon emissions comparable to fossil fuel methane and RNG methane has as similar carbon content to that of fossil fuel methane. Please see the response at Exhibit B.FRPO.1 for additional detail.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 3, Tab 4, page 23

Question:

a) The evidence states that the proposal is expected to impose no material cost increase beyond what customers would bear for conventional natural gas. Please explain how the shift in costs from cap & trade charges to a gas supply charge will impact each of the following: system gas customers, direct purchase customers (non-large final emitters), and large final emitters.
b) What is the potential volume of RNG Union expects to purchase over the next number of years? Please compare this to the volume of gas purchased by Union for facility purposes.

Response:

a) Union is not shifting costs from Cap-and-Trade charges to a gas supply charge. Union is proposing to recover a portion of the cost of RNG from ratepayers through gas costs and Cap-and-Trade charges equal to the amounts they would have otherwise paid. The balance of the cost for RNG will be paid by government funding. Please see the response at Exhibit B.Staff.6 d).

b) As indicated in the response at Exhibit B.Staff.8, given the funding expectations, Union estimates that the total RNG to be purchased annually over the coming years is approximately 4.9 PJ.

   The total facility-related volume forecast for 2018 is 255,182,195 m^3 (approximately 9.9 PJ) as discussed at Exhibit 2, page 7 of 12. Of the total facility requirement, a portion is provided by customers (customer supplied fuel). Of the 9.9 PJ, Union only purchases approximately 3.4 PJ for facility related fuel requirements.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 3, Tab 4, page 23

Question:
Please explain how other jurisdictions may compete with Ontario for RNG that is produced in Ontario.

Response:

The North American natural gas pipeline grid is well integrated, allowing gas injected in the grid to notionally flow to most Canadian provinces and United States. The United States Environmental Protection Agency has instituted a Renewable Fuels program whereby RNG that is used for vehicle fueling generates Renewable Identification Numbers ("RINS") which are traded compliance instruments used by fuel producers and importers. RNG in the United States used for this purpose commands a price premium for RNG. The Lachenaie Landfill in Quebec is Canada's largest RNG producing facility by volume and is currently exporting RNG into the United States market. Markets for RNG are also established in British Columbia and are further developing in Quebec and Vermont where gas utilities are also looking to purchase RNG.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 3, Tab 4, pages 23-24

Question:

a) Please provide further details on the commercial opportunities within Ontario that Union is pursuing.
b) Is Union or any affiliate of Union involved or expecting to be involved in the financing, ownership or operation of any RNG facilities in Ontario? If yes, please explain how Union will negotiate a price with these entities.

Response:

a) and b) Please see the response at Exhibit B.Staff.9 b).

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 3, Tab 4, page 24

Preamble: The evidence states that Union will leverage gas supply contracting processes to facilitate RNG production into Union's system similar to existing contracting processes utilized today for Ontario Local Production (i.e. Rate M13) and other gas purchases.

Question:

a) The use of the word "similar" implies differences. Please provide a list of all the differences between RNG and location production contracting processes.
b) Will RNG producers be required to pay the M13 (or another) rate for gas produced into the Union system?
c) Who is responsible for the capital costs of the natural gas lines that connection the RNG production facility to the Union Gas system? Is this different from the natural gas lines that connection local conventional natural gas producers to the Union Gas system?

Response:

a) Union's existing Gas Purchase Agreements ("GPA"), used to contract for locally produced conventional natural gas in Ontario, have contract terms which include a market-based price for the supply delivered to Union. RNG purchase agreements will differ by stipulating a fixed price for the duration of the contract.

   Existing GPAs also do not have stipulated terms related to volume delivered to Union. RNG purchase agreements will include a maximum volume for which the RNG price will apply in order to eliminate the risk of exhausting government funding before the contract term has ended.

   Finally, existing GPAs are evergreen (do not have pre-determined termination or end date); whereas RNG purchase agreements will stipulate an end date to define the period of time for which the price is fixed.

b) RNG producers will be given the option to contract for the M13 service and sell to Union at Dawn using a separate agreement, or use a GPA to sell to Union at their production station location. RNG producers located in Union's northern franchise areas may be required to use the M13 contract to balance their variable production. RNG producers will be subject to the same rates as existing local production.

c) Capital costs associated with constructing producer stations and connecting those stations to Union’s system are incurred by Union and recovered from producers. RNG producers will be treated the same as local conventional natural gas producers in this regard.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 3, Tab 4, pages 36-37

Question:
Is Union proposing the same contracting process, including provincial funding, for biomass conversion (thermochemical) to RNG? If not, please provide details on the contracting process for this source of RNG, including any subsidies that may be available.

Response:

Union's proposed RNG procurement program involves the purchase of pipeline quality RNG delivered to Union's franchise. This may include many different RNG supply sources, including biomass conversion to RNG.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 3, Tab 5, pages 7-8

Question:

a) What is the number of FTE's related directly to RNG?
b) What is the total cost of the FTE's that are directly related to RNG?
c) How much of this cost is allocated to cap & trade and how much is allocated to gas purchases?
d) How are the costs associated with the RNG related FTE's recovered? For example, does the provincial funding cover the incremental costs related to these FTE's?
e) Given the pending merger of Union with Enbridge, what steps has Union taken to ensure that there is no duplication of effort between Union and Enbridge with respect to all aspects associated with the procurement of RNG supplies?

Response:

a) As identified in Exhibit 3, Tab 5, p.7, Union's 2018 forecasted incremental FTE includes 2.5 FTE related directly to RNG.

b) The fully loaded salaries and wages for the 2018 forecasted incremental FTE in part a) is approximately $0.5 million.

c) 100% of the costs cited in part b) above are included in the Cap-and-Trade Greenhouse Gas Emissions Impact Deferral Account ("GGEIDA") (Account No. 179-152). There are no costs allocated to RNG purchases. Costs related to Union's procurement of RNG supply do not meet the criteria for inclusion in the GGEIDA, as outlined at Exhibit 6, p.7.

d) The costs associated with the RNG related FTE's found at Exhibit 3, Tab 5, pp. 7-8 will be recovered through the GGEIDA. The provincial funding will be used to offset the premium for RNG supply.

e) Please see the response at Exhibit B.Energy Probe.1.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Ref: Exhibit 3, Tab 8, pages 1

Question:
What new business activities is Union contemplating with respect to RNG, other than procuring RNG supplies and connecting the supplies to the distribution system?

Response:

Please see the response at Exhibit B.Staff.9.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP ("Northeast")

Reference: Exhibit 3, Tab 4, Page 18

Preamble: Union suggests its RNG procurement program will provide economic advantages as well as GHG reductions: "By investing in and supporting RNG, Ontario stands to benefit from the diversification of Union's gas supply portfolio and subsequently the development of a provincial RNG industry."

Question:
a) Can Union provide an estimate on the impact of an RNG procurement program on the provincial GDP or number of jobs created in Ontario?

b) If available, please provide supporting documentation.

Response:

a) and b) Union is not able provide an estimate on the impact of an RNG procurement program on the provincial GDP or number of jobs created in Ontario.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP ("Northeast")

Reference: Exhibit 4, Tab 4, Page 19

Preamble: Union indicates that its contracting strategy is driven by the capital intensity of RNG facilities: "Union's RNG plan reflects the requirement of biomass producers to contract for longer-term contracts in order to support capital investment in RNG production facilities. As a result, Union expects to enter into fixed price RNG procurement contracts with terms up to 10 years in duration, subject to provincial funding."

Question:

a) Please provide Union's best estimate for an indicative capital cost for a greenfield RNG supply facility in Ontario, expressed either as a total project cost for daily capacity or on a $/GJ basis.

b) Does Union intend to invest in, build, own, or operate RNG supply facilities, either directly or through an affiliated entity, that would be bidding into the proposed RNG procurement program? If yes, please provide details.

c) Does Union have a financial relationship, co-investment, joint venture, or strategic alliance with a provider of RNG equipment or supply facilities that would be bidding into the proposed RNG procurement program? If yes, please provide details.

Response:

a) Capital costs for facilities are dependent upon the unique characteristics and location of each facility. The 2011 Electrigaz Report (see response at Exhibit B.ED.12.Attachment 1) has a number of examples in section 3.6 - capital cost calculations in Table 2, 3 and 4 as shown below:

Table 2. Total capital costs for agricultural scenarios

Scenario name	Baseline Farm	Large Farm	Coop Farm
	IP	IP	IP
AD process	$ 2,252,000	$ 3,055,000	$ 4,579,000
Upgrading process	$ 1,561,000	$ 2,030,000	$ 2,896,000
Injection, pipe, compression	$ 529,930	$ 529,930	$ 529,930
IDC	$ 105,989	$ 137,032	$ 195,359
Total capital costs	$ 4,448,919	$ 5,751,962	$ 8,200,289

Table 3. Total capital costs for SSO, industrial and WWTP scenarios

Scenario name	SSO	Industrial	WWTP
	IP	IP	IP
AD process	$ 26 093 000	$ 23 278 000	$ -
Upgrading process	$ 3 713 000	$ 4 163 000	$ 1 977 000
Injection, pipe, compression	$ 464 930	$ 487 305	$ 464 930
IDC	$ 1 253 323	$ 1 354 038	$ 51 005
Total capital costs	$ 31 524 253	$ 29 282 343	$ 2 492 935

Table 4. Total capital costs for landfill scenarios[2]

Scenario name	Small landfill	Medium landfill	Large landfill
	IP	HP	XHP
AD process	$ -	$ -	$ -
Upgrading process	$ 4 405 000	$ 6 773 000	$ 13 542 492
Injection, pipe, compression	$ 551 680	$ 2 117 080	$ 3 364 205
IDC	$ 120 967	$ 216 961	$ 575 409
Total capital costs	$ 5 077 647	$ 9 107 041	$ 17 482 106

b) and c) Please see the response at Exhibit B.Staff.9 b).

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP ("Northeast")

Reference: Exhibit 3, Tab 4, Page 22

Preamble: Union proposed use of an RFP process signifies that the supply of RNG is or will be a competitive market: "Union expects that procurement for RNG supply will begin with an RFP process, for delivery of supplies beginning early in 2018."

Question:
Please confirm that the supply of RNG is or will be a competitive market in Ontario.

Response:

Confirmed. The RNG market in Ontario is still in development. Union's RFP process will be competitive and will further the development of the RNG market in Ontario.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP ("Northeast")

Reference: Exhibit 3, Tab 4, Page 22

Preamble: Union's has requested expedited treatment of the RNG procurement plan: "In order to support this timing and secure development of important local resources of RNG, Union requests approval of this proposal as early as possible, but no later than the end of January 2018."

Question:

a) Please indicate the significance of the deadline of January 31, 2018?

b) What would happen if Union did not receive a decision by then?

Response:

a) and b) Please see the response at Exhibit B.Staff.7 a).

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Petroleum Institute ("OPI")

Reference: EB-2017-0255 an Application by Union Gas Limited ("Union"), pursuant to section 33 36(1) of the *Ontario Energy Board Act, 1998,* for an order orders approving rates 34 resulting from the 2018 Cap-and-Trade Compliance Plan.

Question:
What is the carbon benefit to Union by receiving one 10^3m^3 of locally produced natural gas, regardless of its source, as compared to having to transport that same 103m3 of gas from Alberta?

Response:

The cost of carbon to transport gas from other jurisdictions such as Alberta, is included in the pipeline tariff. The carbon emissions costs included in TransCanada's revenue requirement is approximately 1.11% of TransCanada's total net revenue requirement for 2018.[1,2] The specific portion of TransCanada's tolls related to carbon emissions costs is not identified, however, if Union makes the simplifying assumption that the percentage of the revenue requirement related to carbon emission costs similarly translates to 1.11% of tolls on TransCanada pipeline, the carbon cost included in tolls to Union's franchise areas in Union North and Union South is \$0.007/GJ to \$0.020/GJ. The carbon emission costs included in TransCanada's tolls do not affect the cost of Union's compliance obligation. The only fuel cost that results in Cap-and-Trade compliance obligation costs for Union's customers is fuel required to transport gas in Ontario on Union's system. This fuel is included in facility related emissions as discussed in evidence at Exhibit 2, p. 7 of 12.

[1] A88754-2 2018-2020 Mainline Tolls Application - A5Y5H3 ,Section 2.11., pdf pp. 25 - 26
[2] A88754-5 Attachment 3 2018-2020 Revenue Requirement Schedules - A5Y5H6, Attachment 3: 2018 - 2020 Revenue Requirement Schedules, pdf p. 2

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Petroleum Institute ("OPI")

Reference: EB-2017-0255 an Application by Union Gas Limited ("Union"), pursuant to section 33 36(1) of the *Ontario Energy Board Act, 1998*, for an order orders approving rates 34 resulting from the 2018 Cap-and-Trade Compliance Plan.

Question:
What is the carbon benefit to Union by receiving one 103m3 of locally produced natural gas, regardless of its source, as compared to having to transport that same 103m3 of gas from eastern United States that has been produced using high pressure fracturing techniques? Please include the impact of the additional GHG produced using these 46 fracturing techniques.

Response:

Please see the response at Exhibit B.OPI.1.

As discussed in Exhibit B.OPI.1, GHG emissions in other provinces and states are not subject to Ontario legislation and do not represent a carbon cost to Union's ratepayers. Union cannot comment on the additional GHG produced using fracturing techniques or specific conventional production techniques as it will vary depending on the practices of each producer.

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Petroleum Institute ("OPI")

Reference: EB-2017-0255 an Application by Union Gas Limited ("Union"), pursuant to section 33 36(1) of the *Ontario Energy Board Act, 1998,* for an order orders approving rates 34 resulting from the 2018 Cap-and-Trade Compliance Plan.

Question:
What would Union be willing to pay for each of the four forms of locally produced gas noted above? What methodology would Union use to establish these four prices?

Response:

Union assumes that the four forms of locally produced gas referred to by OPI is locally produced conventional natural gas, RNG, hydrogen enriched natural gas ("HENG") and Synthetic Natural Gas ("SNG").

Union purchases locally produced conventional natural gas today and pays producers based on the posted Dawn price.

Union has identified RNG as one abatement initiative that could provide tangible progress towards the transition to a low-carbon economy. RNG would not be feasible for Union to pursue without support and funding from provincial and/or federal governments. Union's RNG initiative targeted for 2018 is contingent upon agreement of program structure with the MOE and MOECC, as well as provincial funding. Procurement for RNG supply will begin with an RFP process which will provide critical information such as cost, contract terms, and quantities. This information will determine the price Union will pay for RNG.

Union will continue to evaluate the viability of other low carbon alternatives to determine if opportunities exist to economically purchase these forms of locally produced gas.

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Petroleum Institute ("OPI")

Reference: EB-2017-0255 an Application by Union Gas Limited ("Union"), pursuant to section 33 36(1) of the *Ontario Energy Board Act, 1998,* for an order orders approving rates 34 resulting from the 2018 Cap-and-Trade Compliance Plan.

Question:
How will Union ensure that the quality of locally produced natural gas, regardless of its source, is treated fairly from a compensation and subsidy perspective, relative to the other sources.

Response:

As discussed at Exhibit B.OPI.3, Union purchases locally produced conventional natural gas today. The price paid for locally produced conventional natural gas is comparable to other conventional sources of natural gas.

RNG has been identified as a carbon neutral alternative to conventional natural gas and supports the transition to the low-carbon economy. RNG would not be feasible for Union to pursue without support and funding from provincial and/or federal governments.

See the response at Exhibit B.APPrO.2 for detail on how Union will ensure that the quality of locally produced natural gas is maintained.

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Petroleum Institute ("OPI")

Reference: EB-2017-0255 an Application by Union Gas Limited ("Union"), pursuant to section 33 36(1) of the *Ontario Energy Board Act, 1998*, for an order orders approving rates 34 resulting from the 2018 Cap-and-Trade Compliance Plan.

Question:
How will Union ensure that their tariffs and facility-related interconnect charges are just and reasonable for all locally produced natural gas?

Response:

Union will leverage existing gas supply contracting processes utilized for Ontario Local Production to facilitate the integration of RNG production into its system. It is expected that tariffs and interconnect charges will be the same for all locally produced natural gas, whether it is conventional or renewable supply.

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Sustainable Energy Association ("OSEA")

Reference: Exhibit 3, Tab 4, Page 18

Preamble**:** "In order to advance the adoption of RNG in support of provincial GHG emission targets and incent the development of the RNG market, additional provincial funding and MOECC program support is required."

Question:
What specific MOECC program support is required to enable Union to meet its goals for implementing RNG, as outlined in the application?

Response:

As outlined in evidence (see Exhibit 3, Tab 4), Union's RNG proposal requires provincial government funding in order to proceed. In order to secure this funding, Union also requires government support (MOECC and MOE) for program design and implementation.

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Sustainable Energy Association ("OSEA")

Reference: Exhibit 3, Tab 4, Page 19

Preamble: "Earlier in 2017, Union and EGD developed an RNG proposal for the province that will achieve the market objectives of the province by providing a mechanism to facilitate RNG procurement funding and cost recovery."

Question:

Was a document setting out this RNG proposal provided to the Province? If so, please provide a copy.

Response:

Please see the responses at Exhibit B.Energy Probe.2 f) and Exhibit B.Energy Probe.5 e).

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Sustainable Energy Association ("OSEA")

Reference: Exhibit 3, Tab 4, Page 19

Preamble:

"As a result, Union expects to enter into fixed price RNG procurement contracts with terms up to 10 years in duration, subject to provincial funding. Based on these RNG contracts, Union will then enter into a contractual arrangement with the province to provide provincial funding equal to the difference between the fixed price of RNG contracted with the producer, and the cost of the conventional natural gas plus the avoided cost of carbon. The inclusion of the avoided cost of carbon is to recognize that customers would have incurred a carbon cost in the absence of RNG."

Question:

a) Does Union propose to enter into a new contract with the Province for each RNG producer?

b) At what stage is Union's negotiation with the Province? Has the Province provided any commitments that it will contribute towards the proposed RNG funding proposal?

c) If the Province ultimately does not agree to Union's funding proposal, how will Union incorporate RNG into its gas supply?

d) What is Union's forecast for the annual subsidy that will be required from the Province based on Union's volume forecasts for the next 10 years?

e) Does Union propose that the Province's subsidy will be part of the $60-$100 million that the Province proposed in the CCAP for introducing renewable content in natural gas?

f) Has Union considered and/or approached the Province about subsidies for another potential customer abatement measures? If so, please describe each abatement measure and the proposed subsidy.

g) Has Union reviewed funding models used for other jurisdictions (e.g. Europe, California, British Columbia and Quebec) that have RNG markets? If so, please describe and provide Union's analysis.

Response:

a) No. Please see the response at Exhibit B.LPMA.8.

b) Please see the response at Exhibit B.Staff.4.

c) Please see the response at Exhibit B.LPMA.5.

d) Please see the response at Exhibit B.Staff.8.

e) Consistent with Union's response at Exhibit B.Staff.4 a), it is Union's understanding that provincial funding for Union's RNG procurement proposal is coming from the $100 million that the province proposed in the Climate Change Action Plan for introducing renewable content in natural gas.

f) Please see the response at Exhibit B.Staff.1 e).

g) Union has not reviewed funding models for other jurisdictions. Ontario's situation is unique and the Utilities have worked with the province throughout the development of this proposal to both diversify Ontario's natural gas supply mix and to meet the province's goals for GHG emission reductions.

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Sustainable Energy Association ("OSEA")

Reference: Exhibit 3, Tab 4, Page 22

Preamble: "Union expects that procurement for RNG supply will begin with an RFP process, for delivery of supplies beginning early in 2018. In order to support this timing and secure development of important local resources of RNG, Union requests approval of this proposal as early as possible, but no later than the end of January 2018"

Question:

a) How many potential RNG producers does Union estimate will be operational and able to supply RNG to Union in 2018? Within the next ten years?

b) What are Union's projections for the annual volumes of RNG it is estimating to introduce in its gas supply portfolio for the next ten years?

c) What criteria will Union use to evaluate the bids from the RFP process?

Response:

a) A sample list of potential RNG production facilities that could be built were submitted to the MOECC and included in the response at Exhibit B.Energy Probe.2 f), Attachment 9.

b) Please see the response at Exhibit B.Staff.8.

c) Please see the response at Exhibit B.Energy Probe.5 e).

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Sustainable Energy Association ("OSEA")

Reference: Exhibit 3, Tab 4, Page 23

Preamble: "To support the development of RNG supply, Union is pursuing commercial opportunities within the province and will continue to work with RNG project proponents and producers. In addition, Union has been in discussions with landfills, waste water treatment plants, industrial sites, and biogas associations seeking to understand the cost of production, the size, the proximity to pipelines required for project viability, and the commercial barriers to market development."

Question:

a) Please provide notes and/or reports from these discussions.

b) Has Union assessed the project with the City of Hamilton's Woodward Avenue Wastewater Treatment Plant to understand the feasibility of RNG and associated costs? If so, please provide reports.

Response:

a) Please see the response at Exhibit B.Staff.9 a) and b) for a summary of the commercial discussion Union has had. The materials provided in Union's response at Exhibit B.Energy Probe.2 f) reflect a summation of Union's knowledge of the potential projects considered in the commercial discussions discussed above.

b) Union has not developed any cost assessment reports for the City of Hamilton's RNG facility.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition (“SEC”)

Reference: [3-4, p.17]

Question:
Please provide a copy of the internal business case that was developed for the RNG proposal.

Response:

No internal business case was developed as there is no capital investment or expected rate of return for Union.

The RNG proposal is designed to impose no material cost impact to ratepayers beyond what customers would bear for conventional natural gas in Ontario’s Cap-and-Trade environment.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: [3-4, p.19]

Question:
Please provide all communications that Union has had with the Province regarding RNG procurement.

Response:

Please see the response at Exhibit B.Energy Probe.2 f).

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: [3-4, p.19]

Question:
Please explain and justify any differences between the Union RNG procurement proposal and the Enbridge RNG procurement proposal.

Response:

Union and EGD's RNG proposals are closely aligned. In each respective utilities' 2018 Compliance Plan filings, different forecasts are used to underpin the long term prices of natural gas that will be used to determine the portion of the RNG to be recovered in gas costs. However, based on recent discussions with EGD, Union expects the same forecast source will be used by each utility in the future.

EGD has also included reference to an optional RNG upgrading service they expect to make available to producers. At this time, Union has no plans to offer this service.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: [3-4, p.19]

Question:
Please detail the minimum requirements to be included in an agreement with the Province for Union if it is to go ahead with its RNG procurement.

Response:

Union must receive assured funding from the government for the full term of the contract prior to entering any contract commitments for the purchase of RNG. The amount of funding received by the government will influence the volume of RNG that Union will be able to procure from producers since the funding bridges the gap between the cost of RNG and conventional natural gas.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: [3-4, p.19]

Question:
Please detail any unique features that Union expects to include in its procurement contracts with RNG producers.

Response:

Please see the response at Exhibit B.LPMA.17 a).

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: [3-4, p.20-22]

Question:
Please provide a list of terms that Union will require in any agreement with the Government for it to go ahead with its RNG procurement?

Response:

Union's 2018 Cap-and-Trade Compliance Plan provides what Union believes to be a reasonable approach for government to achieve its goal of integrating RNG into the province's natural gas system. The terms of an agreement between Union and the province have not yet been defined. Please also see the response at Exhibit B.SEC.4.