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VIA RESS and EMAIL

June 25, 2020

Ms. Christine Long
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario
M4P 1E4

Dear Ms. Long:

Re: EB-2020-0066 – Enbridge Gas Inc. ("Enbridge Gas") – Voluntary Renewable Natural Gas ("RNG") Program Application Undertaking Responses

Please find enclosed undertaking responses from the technical conference held on June 16 and 18, 2020 in the above noted proceeding.

Should you have any questions on this matter please contact the undersigned.

Sincerely,

Brandon Ott Digitally signed by Brandon Ott
Date: 2020.06.25 15:19:43 -04'00'

Brandon Ott
Technical Manager, Regulatory Applications

Cc: David Stevens, Aird & Berlis LLP
All Interested Parties EB-2020-0066

ENBRIDGE GAS INC.

Undertaking Response to ED

To provide forecast RNG volumes form the proposed program, in comparison to Ontario’s total forecast natural gas consumption volumes: or to provid the citation in the evidence for the data

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Response:

Please see Exhibit I.LPMA.15.

ENBRIDGE GAS INC.

Undertaking Response to ED

To provide an aggregated view of the RNG potential as reflected in Enbridge's internal reporting to senior management and otherwise.

Response:

The figures set-out in the table below are based on the Company's discussions with potential Ontario RNG producers. The target commissioning dates of these facilities range from 2020 to 2025.

Potential Ontario Renewable Natural Gas Production Facilities Known to Enbridge Gas			
Feedstock / Biogas Source	**Potential Number of Facilities**	**Potential Annual Production ($10^6 m^3$)**	**Estimated Annual Production ($10^6 m^3$)**
Anaerobic Digestion	22	173	71
Landfill	8	161	149
Waste Water Treatment	5	31	13
Gasification	2	37	30
Total	**37**	**402**	**262**

ENBRIDGE GAS INC.

Undertaking Response to ED

To provide available reports produced by the Canadian Biogas Association Re: RNG Potential.

Response:

Please see the attached Canadian Biogas Association report; *Canadian Biogas Study Benefits to the Economy, Environment and Energy, November 2013*, and press release; *Canadian Biogas Association Calls for Policies to Develop RNG Markets in Ontario*, dated August 25, 2017. For further information published by the Canadian Biogas Association please see the following link: https://biogasassociation.ca/.

Biogas Association

Canadian Biogas Study

Benefits to the Economy, Environment and Energy

Summary Document

November, 2013

Authored by: Kelleher Environmental

Acknowledgements

The Biogas Association wishes to thank the organizations that provided financial contributions to this project:

Anaergia etic EPS HARVEST hydro one Ontario

The information in this Summary Document was developed from a comprehensive study of biogas metrics completed in 2013. All references to the data in this document can be found in the Canadian Biogas Study Technical Document.

The Canadian Biogas Study and this Summary Document were authored by: Kelleher Environmental

Document layout and production by: SEANWOOD designs

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Introduction to Biogas

Biogas is a renewable source of methane, the main ingredient in natural gas. **It can be used for heating and cooling, or to generate electricity that can be used on-site or fed into the distribution grid**. It can be refined into **renewable natural gas that can be injected into gas pipelines**, **or compressed and used as a vehicle fuel**. The entire system, including the energy generating components, is typically referred to as a *biogas facility* or a *biogas plant.*

Biogas is produced when organic materials—anything from crop residues and animal manures to municipal organic wastes and food processing by-products—break down in an oxygen-free environment. The process is called *anaerobic digestion* (AD) and usually occurs in a specialized tank or vessel—the *anaerobic digester*. AD is also the process that generates biogas or landfill gas (LFG) within landfills.

Anaerobic digesters produce not only biogas, but *digestate*, a nutrient-rich slurry that can be applied directly on agricultural land, dried to make animal bedding or processed and marketed as a commercial fertilizer and soil amendment.

The capturing and utilization of biogas is a powerful tool for **reducing greenhouse gases** (GHGs) that are the principle cause of human-induced climate change. GHGs are reduced in two ways: first, the biogas produced is a source of renewable energy that can replace fossil fuels and, second, the capturing of biogas reduces methane, a very potent greenhouse gas that would otherwise be free to escape into the atmosphere.

There are other important environmental benefits. As materials such as animal manures or food wastes are processed in biogas systems, the pathogens are significantly reduced, and nutrients like nitrogen and phosphorous are made more available to plants. These biogas systems reduce and provide greater control of our air and water pollution sources.

All of these critical functions—**generating renewable energy, reducing solid wastes, managing nutrients, reducing greenhouse gases, and mitigating pollution risks**—can be realized from a biogas facility in an economically sound and sustainable manner. The technology is proven and reliable. The required components and services are available across Canada. Biogas production generates diverse revenue streams for farms, industries and municipalities. It creates new jobs in the green economy, and attractive investment opportunities that leverage multiple economic and environmental benefits.

Biogas production is a small but growing industry in Canada, with significant potential for expansion and development. In fact, biogas production is on the verge of a major expansion across North America.

This report reviews the diverse range of biogas production opportunities, and looks at the specific benefits available to farms, businesses and communities. It includes a summary of key data and recent research focused on establishing metrics and measuring the potential of biogas production for energy production, environmental improvement and economic development. This summary is derived from a comprehensive technical report, completed in 2013, and all references can be found in the *Canadian Biogas Study Technical Document*.

Biogas Energy Development Is:

- A solution for agriculture, providing economic, environmental, community benefits.
- A solution for sustainability, providing major GHG, air and water quality benefits.
- Waste management solution which captures energy from waste, diverts waste from landfill, reduces odour, and can fuel waste trucks.
- A renewable energy solution which can produce 3% of our natural gas demand, or 820 MW of reliable, clean, green electricity. This potential is calculated without considering the use of energy crops.

Biogas Potential in Canada

Biogas is a valuable renewable alternative to fossil fuels. It delivers a reliable, dispatchable flow of energy in all weather conditions. AD technologies are proven and the required components and services are available across Canada, so that projects can be developed in a timely and efficient manner. While biogas energy is in the relatively early stages of development in Canada, the opportunities for growth are significant, and would contribute to sustainability in communities across the country. Biogas production offers a wide range of benefits for energy utilization, environmental protection, and economic development.

Energy

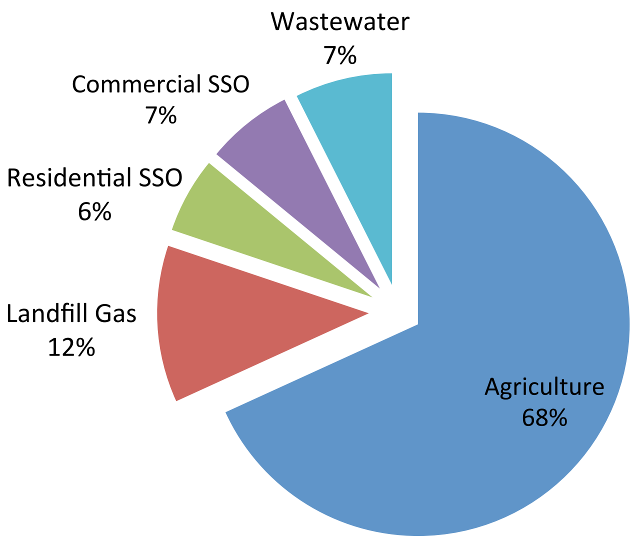
All biogas sources together, without the use of energy crops, have the potential to meet about 3% of Canada's natural gas demand (biogas contribution is 2,420 Mm^3/year of renewable natural gas, or RNG) or 1.3% of its electricity demand (biogas contribution is 810MW).

Table 1: Energy Potential From Biogas Sources in Canada

	Agriculture	Landfill Gas	SSO Residential	SSO Commercial	Wastewater	Total
Electricity Production (MW)	550	95	48	54	60	810
Renewable Natural Gas (RNG) Production (million m^3/year)	1,650	290	140	160	180	2,420
Contribution to Canada's Electricity Demand	0.9%	0.2%	0.1%	0.1%	0.1%	1.3%
Contribution to Canada's Natural Gas Demand	2.1%	0.4%	0.2%	0.2%	0.2%	3.0%

The relative contribution of biogas from the five major sources addressed in the study are presented in Figure 1.

Figure 1: Biogas Energy Production Potential By Source



Environment

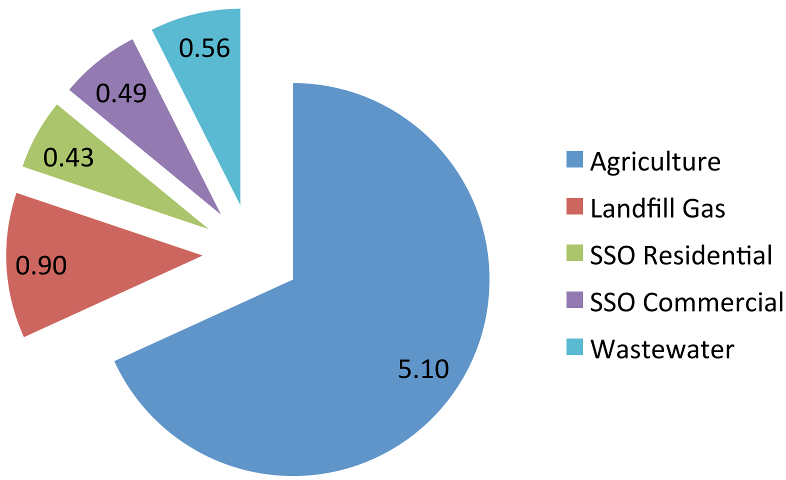
All biogas sources together have the potential to reduce Canada's GHG emissions by 37.5 million tonnes eCO2 per year, which is the equivalent of taking 7.5 million cars off the road. The potential contribution of each biogas source to GHG reduction shows that agricultural digesters have significant potential to reduce GHG (68% of the biogas opportunity), followed by LFG projects (12% of the biogas opportunity). Digesters for commercial and residential SSO and also for wastewater treatment residuals present opportunities of approximately equal size, at 6% to 7% each of the total opportunity.

Further detail on environmental impacts can be found in the *Canadian Biogas Study Technical Document*. Specifically, water quality benefits are in section 3.4.2, nutrient management and soil benefits are in section 3.4.4, and odour impacts are in sections 3.4.3, 4.2.2, 5.2.2, 6.4. All environmental impacts are summarized in Section 10 of the *Technical Document.*

Table 2: GHG Reduction Benefits of Biogas Energy

	Agriculture	Landfill Gas	SSO Residential	SSO Commercial	Wastewater	Total
GHG Reduction (million tonnes eCO2/year)	25.5	4.5	2.2	2.5	2.8	37.5
Cars Off the Road	5,100,000	900,000	430,000	490,000	560,000	7,500,000

Figure 2: GHG Reduction Benefits of Developing Biogas - Equivalent to Cars Off the Road (Millions)



Economy

Realizing the full potential of biogas development would lead to up to 1,800 separate construction projects with a capital investment of $7 billion and economic spin-off of $21 billion to the Canadian economy. These construction projects would create 16,700 construction jobs for a period of one year and 2,650 on-going long term operational jobs. In addition, over 100 new and expanded companies, including biogas system designers and developers, equipment suppliers, laboratories, etc can be supported through this expanded sector. This figure does not include the many construction companies, building supply companies, mechanical and electrical contractors and suppliers who would benefit from biogas development across Canada.

Further detail on economic impacts can be found in the *Canadian Biogas Study Technical Document.* Specifically, economic impacts to farmers are in section 3.5, economic impacts to municipalities are in section 5.3, and all economic impacts are summarized in section 10.

Table 3: Economic Benefits of Developing Biogas Energy

	Agriculture	Landfill Gas	SSO Residential	SSO Commercial	Wastewater	Total
Construction jobs (for one year)	10,200	2,000	1,800	1,700	1,000	16,700
On-going operating jobs	1,320	120	500	460	250	2,650
Direct capital investment ($Billion)	$3	$0.3	$1.7	$1.3	$0.6	$7.0
Indirect economic spinoff ($Billion)	$9.3	$1.0	$5.1	$4.0	$1.7	$21.0

Figure 3: Direct Capital Investment For Biogas Projects ($Billion Can)

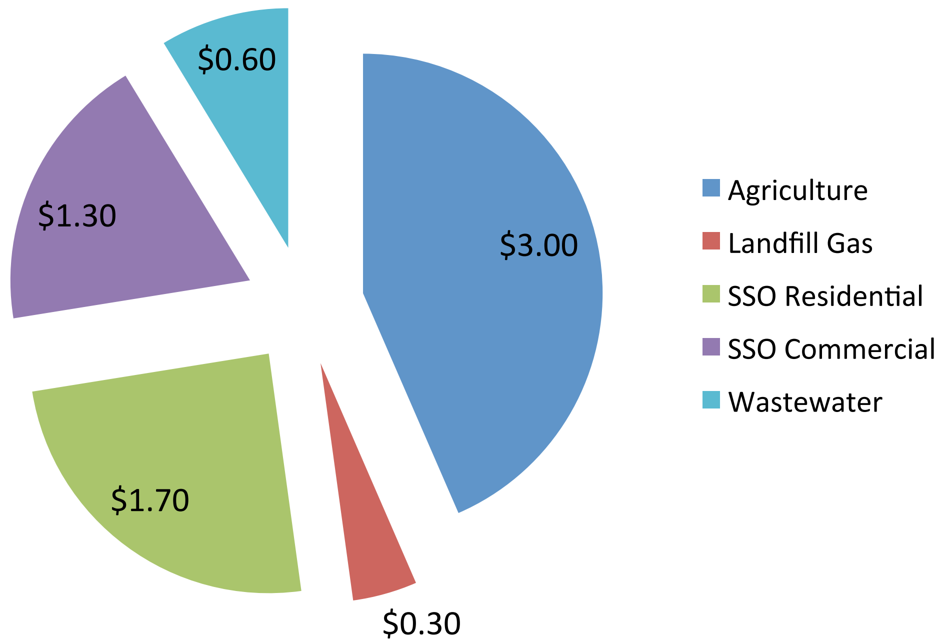
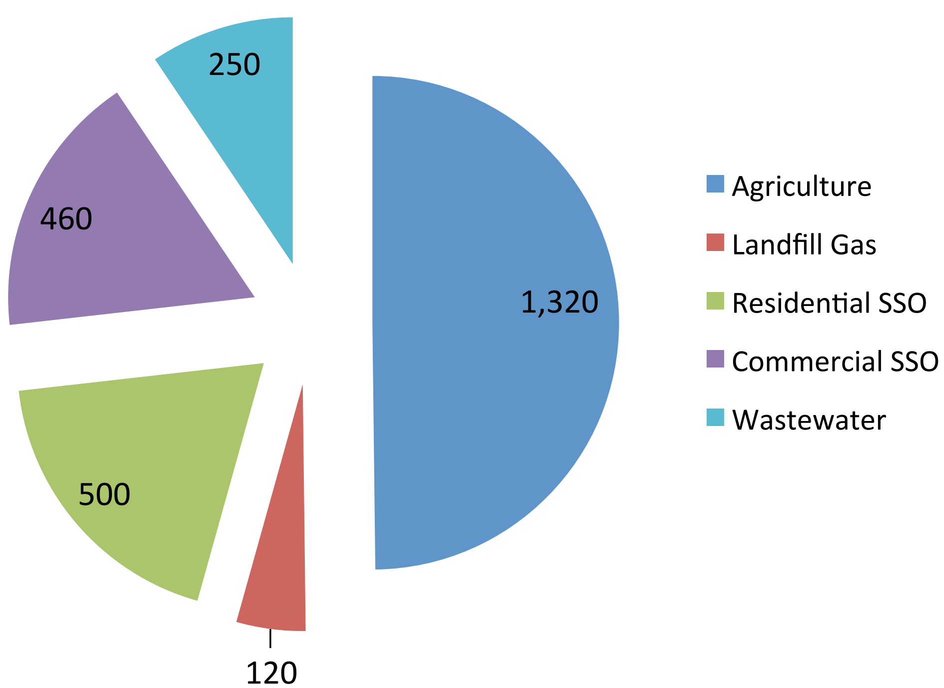


Figure 4: Long-Term Operating Jobs From Biogas Project Development



Biogas production plays many important roles in local economies and energy systems:

- Renewable energy generation
- Waste reduction
- Nutrient management
- Greenhouse gas reduction
- Environmental protection
- Green job creation
- Green investment opportunities

Biogas: Flexible, Adaptable and Renewable

A critical feature that distinguishes biogas from other renewable energy technologies is a high degree of flexibility and adaptability.

Biogas systems may obtain organic matter from a variety of sources and at various quantities. The generation of biogas through the process of AD may be accomplished by two general methods. AD may occur within an anaerobic digester, where the biogas is generated and contained, or AD may occur within buried landfill wastes, where biogas is known as landfill gas (LFG), and collected by a series of wells and pipes. Once biogas is captured, it may be used to power multiple types of energy systems.

The biodegradable materials that can be used as inputs include: crop residues, animal manures and energy crops produced on farms; commercial food wastes produced by businesses and institutions; and, organic wastes collected by municipalities, including materials from the growing number of *Green Bin* programs.

Biogas is a flexible energy source with multiple applications depending on energy requirements and market opportunities. It can be burned as a fuel for heating or cooling, or used to run a co-generation unit to produce both heat and electricity. The electricity from biogas can be fed into the electricity distribution grid, taking advantage of feed-in tariff (FIT) rates where available. It can be cleaned and refined into *renewable natural gas* (RNG), and injected into natural gas distribution pipelines or compressed and used as a vehicle fuel.

This flexibility means that biogas systems can be carefully designed to suit the specific requirements of diverse industries, farms and municipalities across Canada. The range of possible biogas projects—in terms of scale, capacity, complexity and design—is virtually endless.

The feedstocks for biogas systems can be grouped into five broad categories, based on the primary source of the organic material:

- Agricultural organics
- Residential source separated organics (SSOs)
- Commercial SSOs
- Landfill gas (LFG)
- Wastewater treatment residuals

Biogas systems are an economically viable and highly reliable process to manage a wide range of organic residues and make farms, businesses and waste management systems more sustainable.

A biogas project can be highly specialized, utilizing any one of these feedstocks, or designed as an integrated, multi-purpose system accepting and processing multiple materials for a range of energy applications.

1. Agricultural Organics

Anaerobic digester based biogas systems in the agricultural sector are designed to handle the manure from one farm and perhaps neighbouring farms, along with crop residues and energy crops. An advantage of on-farm systems is that the digestate can be spread directly on nearby fields to recycle nutrients and reduce the need for commercial fertilizers.

Agricultural biogas systems are a natural fit on farms as manure is produced continuously from livestock. Manure is rich with methane-producing bacteria and produces significant quantities of biogas when mixed with off-farm organics, integrating the biogas system with existing farm operations. Farm biogas systems are scaled to process the manure and other agricultural biomass and produce distributed electricity generation for a viable economic return on investment. Farms can use heat generated from the biogas system for barns, crop drying, or greenhouses. In some cases, a fraction of the electricity produced is used to power the farm. Capturing the energy from manure, crop residues, and food wastes is smart and economical. For larger farm and food processing operations, generating RNG as a vehicle fuel, or for injection into the natural gas system, may be an option.

Farm-based systems may accept off-farm materials such as commercial food processing by-products. This has several benefits: the digester can achieve better economies of scale, thereby reducing the unit cost of digesting manures and crop residues; the farmer can receive tipping fees; and the digester will generate more biogas. Several provincial governments have recognized these benefits and permit regulated off-farm material processing.

2. Landfill Gas (LFG) Systems

Biogas or LFG is a by-product of the decomposition of organic waste buried in landfills. The operation of a landfill normally requires the installation of a LFG collection system. Currently, there is no requirement to utilize LFG for energy production, and most of the collected LFG is typically flared to the atmosphere. A preferred option is to use the captured biogas as an energy source to create heat, electricity or vehicle fuel. LFG is already produced at landfills, and the infrastructure is in place at many landfill sites to support the services needed for LFG capture, processing and utilization.

Landfills represent relatively large producers of biogas concentrated at a relatively small number of sites across Canada. Many of these sites offer sufficient economies of scale to develop the systems needed for co-generation, production of RNG for injection into natural gas pipelines and/or conversion to fuel for vehicles. Landfills are typically owned by municipalities or waste management companies, so opportunities exist to integrate LFG processing with the anaerobic digestion of other municipal organic wastes. Opportunities also exist to use RNG to power the fleet vehicles used for waste management and other services, creating local closed-loop energy systems.

3. Residential Source Separated Organics

Many municipalities across Canada have implemented *Green Bin* programs to collect household organic wastes, including food wastes. These source separated organics (SSOs) are available as a separate stream of materials for processing, in addition to traditional residential organics such as leaf and yard wastes.

The separation of food waste from other waste has environmental benefits, since organic materials break down in landfills, producing acidic leachate that precipitates metals and creates a potential source of ground and surface water contamination. In addition, the methane produced as these materials degrade naturally is a powerful greenhouse gas unless captured. Longer term, these programs will result in a decrease in landfill gas production as the amount of organics going to landfill decreases, but this benefit is many years into the future.

Residential SSOs represent a substantial and relatively undeveloped new source of material for renewable energy production.

4. Commercial Source Separated Organics

Industrial, commercial and institutional (IC&I) facilities, such as restaurants, hotels, hospitals and food processing plants, generate considerable volumes of organic wastes and by-products. Most of these facilities manage such materials through waste management hauling companies, some of which offer separate collection for source separated food wastes. More often, however, food waste is disposed of in landfills, representing a major lost resource that could be used in biogas production.

Biogas systems can be designed and built by waste generators or waste management companies specifically to process commercial SSOs. They may be scaled to meet the heating requirements of a particular facility, or to manage the by-products on-site from several food processing facilities. Industries with high-strength liquid wastes such as breweries or dairy processing plants may construct AD facilities on-site to manage materials prior to discharge into local sewers or disposal off site.

Commercial SSOs can also serve as feedstock for agricultural biogas systems or municipal systems designed for residential SSOs. Some IC&I generators produce materials such as fats, oils and greases (known in the industry as FOG) which are an asset to the biogas process because they produce high amounts of biogas.

5. Wastewater Treatment Residuals

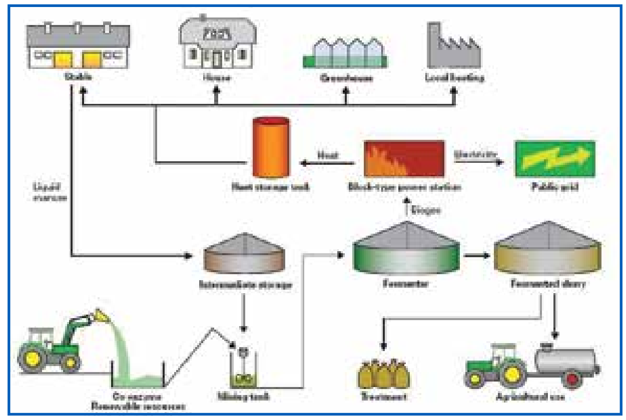
More than 80% of households in Canada live in dwellings connected to municipal sewer systems. All of these systems are connected to wastewater treatment plants. Wastewater is treated in primary or secondary wastewater treatment facilities or water pollution control plants, and each of these treatment options produces wastewater residuals (also referred to as bio-solids or sludge), ideal materials for biogas production.

At some wastewater treatment plants in Canada the biosolids are already processed through anaerobic digestion. The biogas is used for internal plant heating requirements, and the excess biogas is flared. In some cases, biogas is used to produce power for distribution into the electrical grid. In addition, biogas is upgraded to RNG and is injected into the natural gas grid. There are a number of co-generation facilities in place in wastewater treatment facilities across Canada, but a large amount of biogas is flared with no energy recovery. This large source of biogas presents a significant opportunity to increase the production of green energy from biogas which is already being produced.

Biogas Systems Can Integrate Many Sources and Uses

As anaerobic digestion technologies develop and expand across Canada, there will be opportunities to develop highly integrated biogas production strategies, with multi-purpose AD facilities functioning as intermediaries that convert organic materials from multiple sources into a range of different energy outputs adapted to suit local needs and market opportunities. For example:

- Materials from several farms and food processing plants could be transferred to a centralized biogas facility serving a rural or semi-urban area. The biogas produced could be used to heat commercial facilities, fuel a co-generation plant, or supply a district heating system, while also delivering surplus electricity into the local distribution grid. Digestate could be distributed on nearby farmland or processed on-site to create animal bedding or a marketable soil amendment including fertilizers.



- Biogas from a large municipal facility located at a landfill site to process LFG could be expanded to accommodate biogas systems for residential and commercial SSOs. The biogas could be used to power a co-generation system that provides heat for on-site facilities or nearby customers as well as electricity that can be fed into the local distribution grid. Economies of scale could be sufficient to justify refinement of biogas into RNG for injection into natural gas pipelines or to power municipal fleet vehicles. The capacity to produce both electricity and RNG, for municipal uses as well as off-site distribution, would provide significant flexibility to adapt to changing needs and market conditions.

The case study that follows illustrates how a biogas system can integrate many sources for multiple uses.

Case Study:
Closing the Loop: From Organic Wastes to RNG-Powered Waste Management Vehicles
Surrey, BC

Overview

In October, 2012, the City of Surrey, BC, launched a bold new waste management plan consisting of three components:

- Mandatory source separation of organic wastes by residences and businesses;
- Exclusive use of natural gas-powered vehicles for waste collection and recycling services;
- Construction of a new waste-to-biofuels production facility where organic wastes will be processed into a renewable natural gas (RNG) for the waste collection and recycling vehicles.

This plan will create a closed loop system that converts a significant portion of the City's solid waste stream into a clean, renewable vehicle fuel for waste management services. The plan will cut operating costs, reduce air pollution and greenhouse gas (GHG) emissions, and serve as a closely watched model for communities across North America.

Features

- Surrey has entered into a seven-year waste-disposal contract with BFI Canada that requires the exclusive use of natural gas-powered vehicles. This is a first for municipalities in Canada and also for BFI, a major waste management company.
- The trucks incorporate latest gas-powered engine technology and operate on compressed natural gas (CNG). Gas-powered trucks in general emit 23% fewer carbon emissions and 90% fewer air particulates compared to diesel-powered trucks, while enabling the City to reduce dependence on diesel fuel, which has been expensive and subject to volatile price swings.
- Replacing each diesel truck with a natural gas truck is the equivalent of taking 475 cars off the road from a GHG perspective.
- Construction of an Organic Waste Bio-fuel Processing Facility, on City-owned property adjacent to the Surrey Transfer Station, is expected to start in 2014. It will produce RNG for vehicles and possibly for injection into the region's natural gas pipeline network, as well as digestate to be processed into fertilizer and soil amendment for distribution through local retailers.
- The facility will be developed as a Public Private Partnership. The Government of Canada, through the PPP Canada Fund, will contribute up to 25% of the capital costs.
- Local governments in BC are subject to a carbon tax of $30 per tonne. The City of Surrey, by signing the BC Climate Action Charter and committing to becoming carbon neutral, is eligible for the Climate Action Rebate Incentive Program and will receive carbon credits for the innovative bio-fuel program.

Future Plans

Surrey's new Organic Waste Bio-fuel Processing Facility, when completed, will enable full implementation of the City's Waste Management Plan, which in turn will help the City achieve the Metro Vancouver regional goal of diverting 70% of all wastes from landfills by 2015. A regional ban of all organics from landfill disposal has been proposed.

The Benefits of Biogas Production

Energy

- Fuel for boilers, furnaces and chillers
- Co-generation of combined heat and power (CHP)
- Grid-tied power for distribution to local utilities
- Support for distribution grid resilience and efficiency
- Renewable natural gas (RNG) for vehicle fuel
- RNG for injection into natural gas pipelines

Environment

- Reduction of greenhouse gases (GHGs)—carbon dioxide and methane
- Stabilization of nutrients for reduced water contamination risks
- Substantial reduction of pathogens in manures and food wastes
- Reduced emissions of volatile organic compounds (VOCs)
- Reduction of odours

Economy

- Diversification of farm revenues
- Production of marketable fertilizers and soil amendments
- High-quality digestate for improved land management
- Municipal waste management efficiencies
- Revenues from sale of grid-tied electricity—eligibility for feed-in tariff (FIT) subsidies
- Potential carbon emission credits
- Cost savings and/or revenues from RNG

Biogas Benefits: Energy, Environment and the Economy

Biogas production through anaerobic digestion is a multi-purpose process providing an array of benefits for farms, businesses and communities. The benefits can be grouped into three broad areas:

- Energy
- Environment
- Economy

Biogas projects can be designed to optimize benefits in each category, responding to local needs and opportunities.

Energy

Biogas-powered generators can be used to supply electricity to the grid. This solution is most common for farms where a single biogas system can power ten or more other farms. The biogas system can supply emergency back-up power, and create an independent power source for residences, barns and other facilities.

Biogas producers located on rural distribution systems utilizing synchronous generators have demonstrated positive impacts on distribution system operations by providing voltage support and improving power quality.

Unlike other renewable energy alternatives such as wind and solar power, biogas delivers a reliable flow of energy regardless of weather conditions and has a very high capacity factor. The flexibility and reliability of biogas systems are important assets. They can produce power during periods of peak system demand, be dispatched down, and configured to store fuel during periods of excess power or surplus base load.

Biogas, as a source of methane, is a valuable renewable alternative to fossil fuels. It can be used directly to fuel on-site boilers, furnaces or chillers for larger applications such as crop drying, barns, greenhouses, swimming pools, commercial facilities and industrial processes.

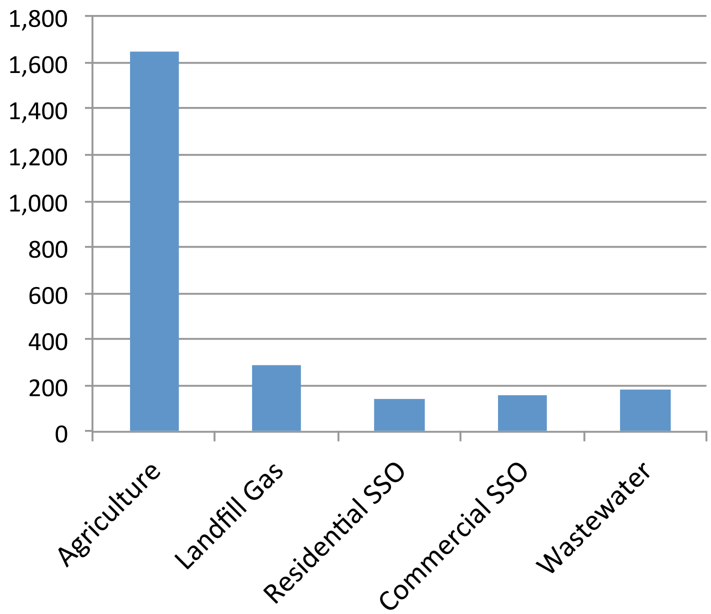
Biogas can be used to fuel co-generation systems in combined heat and power (CHP) configurations.

Finally, the ability to clean and refine biogas into renewable natural gas (RNG) is a vitally important addition to the portfolio of energy options available to biogas producers. RNG can be produced to meet all of the technical standards and requirements of conventional natural gas, and therefore offers the same degree of versatility. Already, some European countries are fueling their cars, buses, and trucks with RNG. Several companies in the

USA are using RNG for milk hauling and municipal truck fleets, and one large Canadian municipality (Surrey, BC) will fuel its garbage collection fleet with RNG produced from a biogas facility processing *Green Bin* materials starting in 2015.

In BC, residents can pay about $5 more per month for an average home, and designate 10 per cent of the natural gas they use as renewable natural gas. FortisBC then injects the equivalent amount of renewable natural gas into their distribution system. The program is sold to residents on the basis that it helps reduce their carbon footprint and supports sustainable energy produced in BC. RNG is also offered to BC businesses. Projects supplying the RNG are featured on the FortisBC website.

Figure 5: RNG Production Potential (Mm^3/year)



Environment

Biogas projects reduce two critically important greenhouse gases—carbon dioxide (CO_2) and methane (CH_4). Carbon dioxide emissions are reduced whenever biogas is used as a substitute for fossil fuels such as diesel or natural gas. Methane, which is 21 times more potent than CO_2 as a greenhouse gas, is captured within an anaerobic digester or from a LFG collection system and converted to energy.

This dual GHG-reduction impact makes biogas projects a very effective strategy for helping communities meet GHG-reduction targets. Some biogas projects may become a significant source of carbon emission reduction credits as carbon credit markets increase in value.

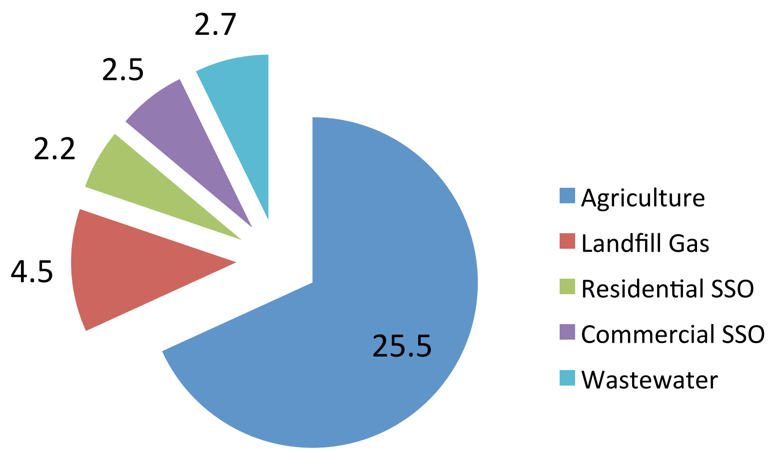
The use of an anaerobic digester to process organic wastes helps to protect water quality. Pathogens are reduced up to 99% when compared with undigested manure and the nutrients in the digestate are more available to crops. Energy can be recovered through the digester and the liquid digestate from the process is fully contained and managed. Proper management and use of liquid digestate can significantly reduce the risks of pathogens and pollution risks in soils, groundwater, and surface water.

Biogas systems protects water resources in another way—biogas requires minimal amounts of water for energy production in comparison with other biofuels.

Biogas projects also help to protect air quality. The destruction of VOCs and other smog pre-cursors through the capture of decomposing organic material helps to improve air quality by reducing the potential for smog and the associated respiratory health and safety concerns.

Anaerobic digesters can reduce or eliminate odours from farms, landfills and waste processing facilities. AD occurs in a tightly controlled environment where exhaust air is cleaned in a biofilter. Digesters tend to have much tighter and more effective odour control mechanisms than other processing operations. Odours are also reduced whenever decomposing organic material, which contains trace amounts of sulphur, is captured.

Figure 6: GHG Reduction From Biogas Projects (million tonnes eCO2/year)



Economy

Biogas production offers a range of interrelated economic benefits. There are opportunities to diversify farms, business and community revenues beyond conventional sources. The largest revenue stream often comes from the sale of renewable energy into the power grid. This is a primary driver for biogas project investments, particularly in jurisdictions such as Ontario with feed-in tariff rates for renewable power. Even when biogas electricity is used on-site prior to exporting the excess electricity, savings from reduced conventional energy use can be realized.

Other potential revenue streams include nutrient recovery and management, tipping fees, thermal usage, bedding savings for farms, and carbon offsets, where available.

Additional economic benefits are also realized from digestate. The digestate has good soil enhancement qualities and can be applied to growing crops without damage making it a marketable and valuable soil amendment. The digestate delivers nutrients in a form that is more consistent, more readily absorbed and more concentrated, reducing the need for and cost of synthetic fertilizers. Handling digestate vis-a-vis storage, mixing, pumping and spreading is easier and requires less energy resulting in reduced costs.

Biogas production facilities that are designed to process landfill gas or SSOs create economic benefits that are typically realized by the municipalities or waste management companies that own these facilities, as well as the broader community. Direct revenue sources include commercial tipping fees for SSOs and renewable energy revenues.

Anaerobic digestion of SSOs helps to preserve landfill capacity, a valuable and limited resource in many communities. The footprint of anaerobic digestion systems is much smaller than composting facilities of similar capacity, which supports the efficient use of land and increases the feasibility of locating facilities in or near urban areas.

The economic benefits of biogas production at wastewater treatment facilities include energy savings, and the potential for renewable energy revenues, typically accruing to the municipalities that own most of these facilities across Canada. Many wastewater treatment facilities in Canada are large, and the possibility of integration with other community biogas sources such as LFG and SSOs creates the potential for improved economies of scale. This, in turn, creates further opportunities for developing diverse energy revenue streams through both electricity and RNG production.

Over 100 new and expanded companies are operating across Canada as a result of the recent interest in biogas projects. These companies include biogas system designers and developers, equipment suppliers, laboratories, etc. This number does not include all the construction companies and other related industries which benefit from development of the biogas sector.

Construction of over 1,260 biogas facilities across Canada would result in capital investment of $7 billion, with an economic spinoff of $21 billion. Construction projects would create about 16,700 FTE jobs for one year, and about 2,650 long term operational jobs.

Figure 7: Indirect Economic Spinoff from Biogas Project Development in Canada ($Billion Can)

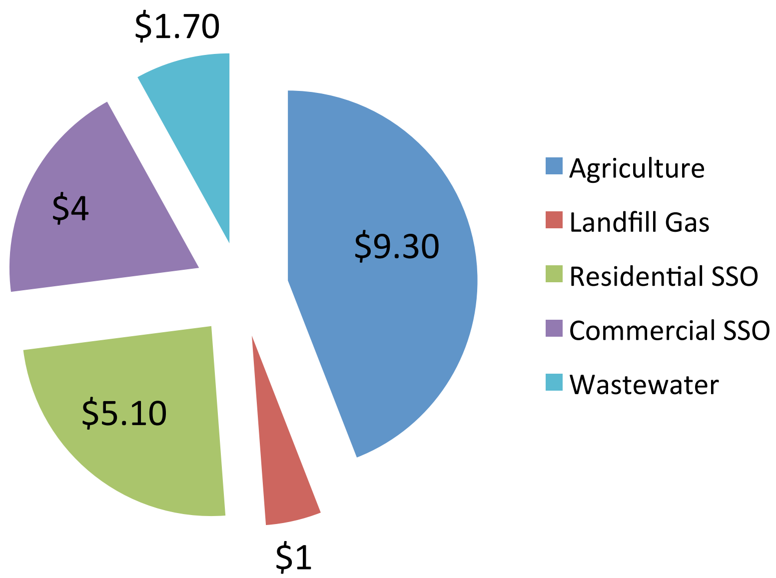
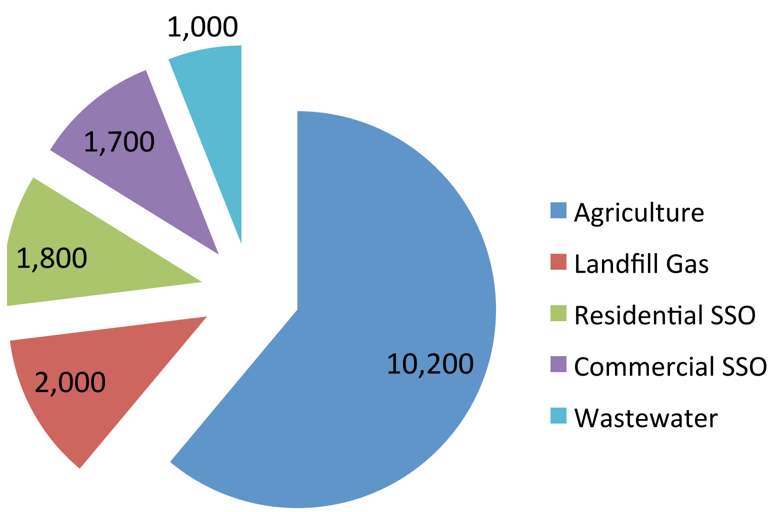


Figure 8: Construction Jobs From Biogas Project Development in Canada (For One Year)



The Biogas Vision: A New Renewable Energy Network

The production of biogas is now underway from all major sources—agricultural organics, landfill gas, residential and commercial SSOs, and at wastewater treatment facilities. In general across Canada, however, biogas production is still in the early stages of development and the potential for growth and expansion is significant. It is estimated that the total production of biogas from all sources combined, without the use of energy crops, could be equivalent to 2,420 Mm^3 per year of RNG (representing 3% of Canada's natural gas demand) or up to 810 MW of electricity from renewable sources (representing 1.3% of Canada's annual electricity demand). Biogas could therefore contribute up to 3% of Canada's energy needs through a reliable, renewable source.

The full realization of biogas potential in Canada presents many challenges. In practice, any renewable energy alternative must service multiple energy needs and markets, integrate well into existing energy distribution systems and networks, and offer a range of practical and sustainable economic opportunities.

In this respect the inherent flexibility, adaptability and reliability of biogas production offers critically important advantages.

The long-term vision for biogas development includes an extensive and diverse portfolio of biogas projects on farms, commercial sites, landfills and wastewater treatment facilities across Canada. Facilities will range from the small and simple, to the large and complex.

Some systems will be the backbone of a micro-grid, supplying site-specific energy needs and contributing to local strategies for energy independence, self-reliance and energy cost reduction. Most will be connected to existing energy distribution systems. In the case of electricity, grid-tied biogas-powered generators will serve as multiple point sources of distributed energy generation peak power, reducing line losses and increasing service stability and power quality. The capacity to store fuel during periods of surplus power will be valuable assets, contributing to distribution system reliability and efficiency.

In the case of renewable natural gas (RNG), some biogas systems will inject RNG into natural gas pipeline networks, representing unique new sources of feedstock that require no drilling or fracking, yet match the quality and end-market versatility of conventional natural gas. RNG in compressed form will provide an increasingly important renewable vehicle fuel. Most importantly, RNG provides consumers with a renewable energy option.

Biogas, in short, can make major contributions to the efficiency, cost-effectiveness and resilience of energy systems at the local, regional and national level, while at the same time playing a key role in environmental protection and greenhouse gas reduction.

To accomplish all of this, biogas production draws from the many common organic materials cited above—agricultural manures, crop residues and energy crops, landfill gas, residential and commercial SSOs, and from wastewater treatment facilities. Most of these have traditionally been viewed as wastes, and in many cases simply allowed to degrade where they add to the burden of greenhouse gases, or have been flared-off with no energy recovery. Biogas production instead captures these materials and converts them into a practical form of renewable energy, while simultaneously producing high-grade fertilizer for agricultural crops and soil restoration.

It is an effective *closed-loop* solution to a wide range of conservation and resource management challenges as Canadians move toward a more sustainable economy.

Figure 9: Biogas Vision for Canada—Integrated Renewable Energy Network

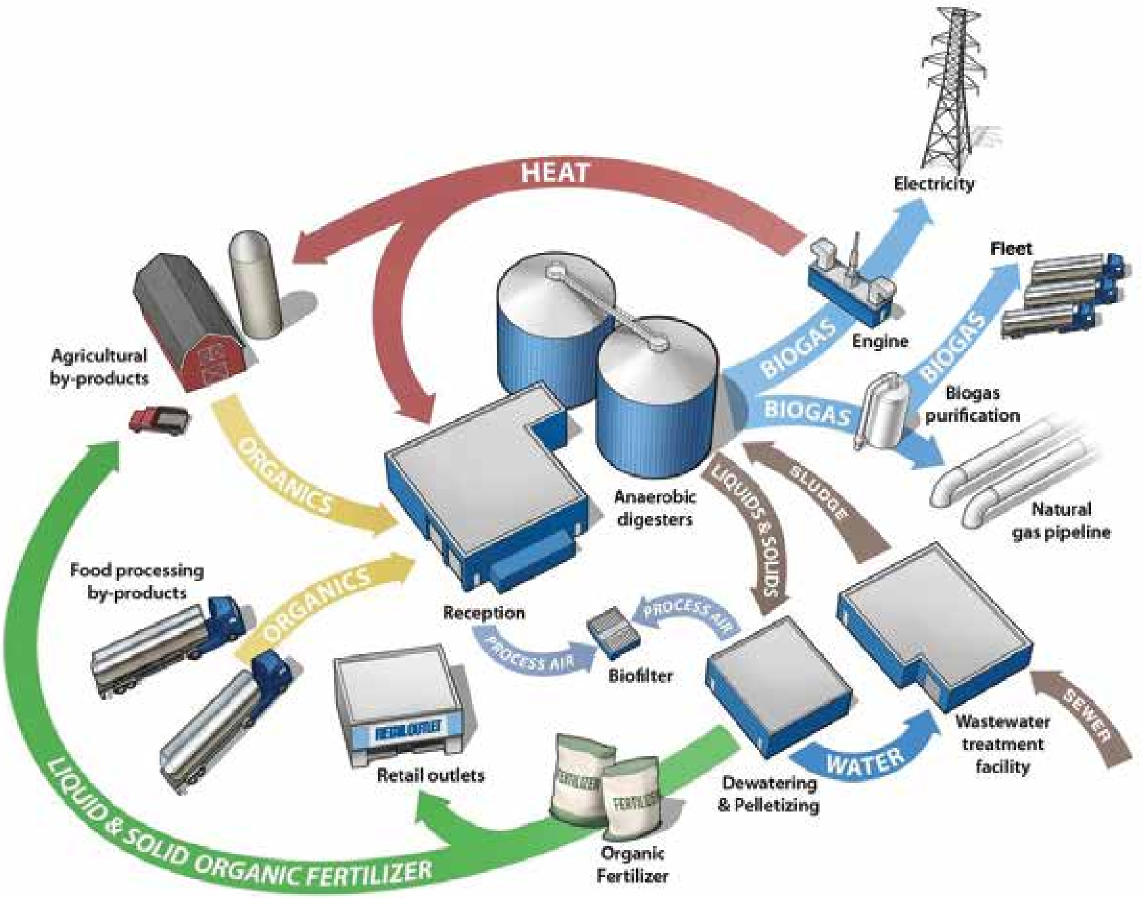


illustration by Stormfisher

Biogas Metrics: Measuring the Potential of Biogas Production

A growing body of data is available to support the evaluation of biogas production opportunities by farms, businesses, communities and governments at all levels. These data provide metrics and performance indicators in key areas: renewable energy production, environmental improvement and economic development.

Agricultural Organics

Table 4: Energy, Environmental and Economic Benefits of Agricultural Biogas Projects in Canada

Energy	• Agricultural digesters in Canada using 50% of available manure and crop residues have the potential to produce 1,650 Mm^3/year of methane, which can be converted to 550 MW of renewable electricity. • Together, agricultural digesters could supply 2.1% of Canada's natural gas demand. • If energy crops were added, agricultural digesters could produce an additional 800MW of electricity, contributing up to 2% of Canada's electricity demand. • Biogas systems provide unique benefits to the electricity system as they are distributed throughout the grid and can provide electricity supply, reliably, regardless of the weather, 24/7. • Biogas can be stored when the electricity is not required, a significant benefit in some systems. • Electricity generated by biogas systems is synchronous and can provide voltage and power quality support to local, rural feeders which may be challenged by poor power quality.
Environment	• Anaerobic digestion of animal manures reduces pathogenic bacteria by up to 99%. • The addition of a biogas system at a dairy farm can reduce methane emissions by 75%. • 6.4 Mt eCO2 equivalent were emitted from manure management in 2011. • Digesting half of animal manures and crop residues across Canada would reduce GHG emissions by an estimated 25.5 million tonnes of eCO_2 per year. This is the equivalent of taking 5,100,000 cars off the road. • Biogas systems typically achieve odour reduction in the order of 80%. • 90% of the phosphorus and 43% of the total nitrogen can be concentrated in the waste solids, enabling better control and efficiency in nutrient management. • Digestion reduces weed seeds by up to 99%. This can reduce farm costs for herbicides while reducing the requirement for the broad-spectrum application of synthetic pesticides.
Economy	• On-farm biogas systems create a number of revenue streams that support income diversification and long-term sustainability for farm families. They provide an opportunity, and sufficient income, for an additional full-time job. • Renewable energy is the primary income source for biogas systems; other potential revenue streams include tipping fees (from off-farm materials), sale of thermal energy, bedding savings, nutrient recovery and carbon offsets where available. • Agricultural digesters provide local employment, consisting of 1.2 FTE at the digester and additional haulage jobs if off-farm waste is accepted. • Avoided cost of fertilizer is estimated to equal \$15 per animal unit per year. • Solid fiber in digestate may be extracted using a liquid/solid separator to make bedding for use on the farm. This can save as much as \$84 per cow per year. • Surplus digested manure solids bedding can be sold as a soil additive for up to \$20 per tonne. • It is estimated that the construction of more than 1,100 digesters to process 50% of available manures and crop residues would create 28,900 construction-related jobs for one year. • Establishing 1,100 farm digesters across Canada will create about 1,320 permanent operational jobs across Canada. • Construction of 1,100 farm digesters would require a total investment of \$3.5 billion with an economic spin-off of \$10.5 billion for a total economic impact of \$14 billion across Canada.

Case Study:
Farm-Based Biogas Production with a Feed-in Tariff (FIT) Contract for Renewable Energy Generation
Cobden, Ontario

Overview

Fepro Farms is a dairy farm with 300 head of cattle, including 142 milking cows, as well as 350 acres of corn, 70 acres of small grain and 210 acres of alfalfa. It is owned and operated by brothers Paul and Fritz Klaesi and located in Cobden, Ontario, near Ottawa.

Biogas-powered generators on the farm supply electricity for all farm operations and residential uses. Heat captured from the generators is used to supply hot water and the heating requirements of the biogas system. Surplus electricity is fed into the electricity distribution grid and sold under a Feed-In Tariff (FIT) contract. The FIT Program was developed by the Ontario Power Authority (OPA) to encourage the development of renewable energy generation projects. Qualified renewable energy producers have an opportunity to enter into a 20-year contract with the Province of Ontario, through which the Province agrees to purchase all electricity that is delivered into the distribution grid, at a price sufficient to cover the costs of the project with a reasonable return on investment.

Fepro Farms uses biogas production to meet on-farm energy needs and create a substantial new revenue source. The system also provides an efficient and environmentally sound method for converting animal manure into a high-quality, nutrient-rich digestate for land application.

Features

- A 500 cubic metre (m^3) anaerobic digester generating 50kW of electricity was installed at Fepro Farms in 2003. This system was expanded to its current capacity of 2,500 m^3 and a 500 kW in 2007.
- The primary feedstock for anaerobic digestion is manure from the farm. In addition, off-farm organic residuals collected from restaurants, grocery stores and commercial SSO, are heat treated prior to digestion and used to increase biogas production.
- Heat is used seasonally for grain drying and heating of buildings on site.
- The digestate, a nutrient enriched soil amendment, is land applied to enhance crop production.
- Since signing the FIT contract, Fepro Farms has been able to eliminate electricity costs that were over $30,000 per month, while generating an additional revenue source.
- The biogas system also has a number of environmental benefits: the capture of methane from manure helps to reduce greenhouse gas emissions. Pathogens are reduced in the high-temperature anaerobic digestion process, thereby reducing the risk of ground or surface water pollution. The odours associated with conventional manure spreading are removed. The off-farm materials used in the process are diverted from local landfills.

Creating Opportunities

The biogas project at Fepro Farms represents an innovative form of local economic development. The project has supported renewable technology providers who are developing expertise and capacity in an emerging market. It has created opportunities for on-farm revenue diversification and employment for family members, at a time of limited growth in the dairy industry. By delivering reliable, dispatchable electricity into the distribution grid, the project is also helping Ontario move toward a cleaner, more sustainable energy system.

Landfill Gas

Table 5: Energy, Environmental and Economic Benefits of Landfill Gas Projects in Canada

Energy	• An estimated 68MW of electricity and large amounts of heat are produced through existing LFG projects across Canada. • The opportunity exists to almost double existing energy capture at landfills across Canada economically, resulting in significant GHG reductions. • About half of the methane captured at landfills across Canada is used for energy production while the other half is currently flared with no energy recovery. • There is significant potential to utilize LFG at existing sites to produce 95 MW of electricity economically. Alternatively, the recovered LFG could be upgraded to RNG and injected into the natural gas grid, or be used to fuel trucks and replace diesel which is a higher GHG emitting fuel.
Environment	• There are more than 10,000 landfills of which 800 are active landfills in Canada. • LFG is the third largest source of anthropogenic methane emissions in Canada. • LFG represents 3% of Canada's national GHG emissions. • LFG is generally the largest source of GHG over which a local community has direct control. • Approximately 27 megatonnes (Mt) of eCO_2 are generated annually from Canadian landfills, of which 20 Mt eCO_2 are being emitted annually. Approximately 7 Mt eCO_2 are captured and combusted at Canadian landfills today, representing the equivalent of removing about 1.5 million cars from the road. • LFG biogas projects significantly reduce community GHG emissions and help communities to meet GHG reduction targets. For example, the LFG project in Salmon Arm BC reduces eCO_2 emissions by 1,250 tonnes, the equivalent of taking 250 cars off the road, while supplying heating energy for 300 homes. • Each diesel truck replaced with a gas fueled truck is equivalent to taking 475 cars off the road from a GHG perspective.
Economy	• There are at least 41 economically viable LFG projects which are currently undeveloped across Canada • The estimated capital cost of these 41 projects is $322 million with net annual revenues of $57 million. • Each new LFG project creates 2-3 full time local operating jobs long term and creates $3 in economic output for each $1 spent on construction. • The 41 LFG projects would create about 80-120 long-term operational jobs. • A typical 3 MW LFG electricity project adds more than $1.5 million in new project expenditures for the purchase of equipment during the construction year • A typical 3MW LFG project increases economic output by $4.3 million and employment by 20-26 people during the construction year. • LFG projects will be a significant source of carbon emission reduction credits as the carbon credit market increases in value. • GHG credits of 3.7 million tonnes CO_2 per year can be created by landfills across Canada at a very attractive rate of under $4/tonne. This provides significant opportunities for landfills to capture and reduce GHGs and sell credits at a profit. • Where LFG is used to fuel truck fleets, CNG-powered trucks are significantly cheaper to operate than conventional diesel-powered alternatives. Large LFG projects provide the opportunity to produce RNG for truck fleets.

Case Study:
Converting Landfill Waste into Green Energy - Progessive Waste Solutions (BFI Canada) Launches Largest Transformation Project of Biogas Into RNG in Quebec

About one third of the waste from Greater Montreal is landfilled at the Lachenaie landfill in Terrebonne, Quebec. In September, 2013, Progressive Waste Solutions (BFI Canada), a subsidiary of the Canadian company Progressive Waste Solutions, announced that it is investing $40 million to convert the biogas produced by the waste from Greater Montreal into RNG.

Approximately 17,000 m^3/hour will be used to power the equivalent of 1,500 heavy trucks for a period of twenty years, avoiding the consumption of 350,000 barrels of fuel oil per year.

The new plant is expected to reduce GHG emissions by about 1.2 million tonnes of carbon dioxide (CO_2) over a period of ten years.

The new biogas processing facility should be in operation by mid-year 2014. The RNG produced will be injected into the TransQuébec & Maritimes Pipeline adjacent to the landfill in Terrebonne.

Progressive Waste Solutions (BFI Canada) opened the first power plant fueled by biogas in Quebec in 1996, which generates electricity for the equivalent of 2,500 homes each year.

Progressive Waste Solutions (BFI Canada) operates the largest fleet of trucks running on compressed natural gas (CNG) in the waste collection and recyclable materials industry. By the end of 2013, the company plans to have about 150 trucks powered by CNG in Canada. In 2014, it is expected that 50 to 55% of the total number of new trucks, acquired through the normal fleet replacement, will run on CNG.

Residential Source Separated Organics

Table 6: Energy, Environmental and Economic Benefits of Residential SSO Biogas Projects in Canada

Energy	• About 40% of the residential waste discarded in Canada each year consists of biodegradable material (food, etc.) that could be used to generate green energy. • The Green Bin waste from 300,000 households is sufficient to produce 1.4MW of electricity, which is sufficient to meet the electricity needs of 800 homes. • Capturing half of the discarded organics in Canada could produce 48MW of power, or 140Mm^3/year of RNG. • Municipalities involved in SSO digestion can integrate SSO biogas utilization with other potential biogas sources such as wastewater treatment plants and LFG facilities.
Environment	• Anaerobic digesters have a very small footprint compared to other organics processing technologies, and can therefore be located at existing waste management sites or in urban areas. • Capturing half of the discarded residential organics in Canada would result in reduction of 2.2 million tonnes eCO2/year, the equivalent of taking 430,000 cars off the road. • Anaerobic digestion, over the life of a project, has a positive net energy balance, while other technologies consume net energy. • AD of SSO facilitates the conversion of municipal fleets from diesel to RNG which can be produced by the digester in a closed loop system. Replacing a diesel truck with a CNG truck is equivalent to taking 474 cars off the road from a GHG point of view.
Economy	• The capital investment required for digesters across Canada is about $1.7 billion, with an economic spin-off of an additional $5 billion. • The Dufferin Digester in Toronto (which is the only municipal AD facility currently operating in Canada handling a mixture of residential and commercial SSO) processes 25,000 to 40,000 tonnes/year with a staff of 13 running three shifts per day. • Up to 494 long term operations jobs could be created across Canada should the biogas potential of residential SSO be developed. • Green Bin programs can divert 200kg/household/year from disposal and into productive uses. A city of 300,000 households could divert 60,000 tonnes/year of Green Bin material, saving 60,000 m^3 of landfill capacity annually, thereby delaying the need to establish a new landfill facility, which is becoming increasingly challenging across Canada.

Commercial Source Separated Organics

Table 7: Energy, Environmental and Economic Benefits of Commercial SSO Projects in Canada

Energy	• 54MW or more and at least 160 Mm^3/year of RNG could be produced from commercial SSO across Canada which is currently disposed.
Environment	• About 23% of the solid waste generated in the industrial, commercial and institutional (IC&I) sector is food waste from businesses and institutions. • About 6 million tonnes of food waste is discarded in Canada each year. This food is a significant resource for digestion and renewable energy production. • Digesting half of the commercial organics currently disposed would save 2.2 million tonnes/year of eCO_2. This is equivalent to taking 490,000 cars off the road.
Economy	• Construction of 38 digesters in Canada to digest available commercial SSO could generate $1.5 billion in capital expenditures with a spin-off of $4.5 billion across Canada. • The construction of up to 40 digesters would result in 1,800 direct and 5,400 indirect jobs. • Operation of up to 40 digesters would produce 460 long term operating jobs across Canada.

Case Study:
Harvest Power Fraser Richmond BC Site

On 11th September, 2013, Harvest Power, along with its partners, officially launched its Energy Garden in British Columbia, the largest commercial-scale high solids anaerobic digester in North America. The Energy Garden is located at Harvest's site in Richmond, B.C. and has the capacity to convert up to 40,000 tonnes of food and yard waste per year from area homes, businesses, restaurants and supermarkets into clean energy and compost.

"This facility represents the innovation, passion and commitment required to usher in the future of organics management," said Paul Sellew, Harvest Power founder and CEO. "We are excited to continue our partnership with the Metro Vancouver and the City of Richmond community to cost-effectively convert organic materials once destined for the landfill into clean energy and compost products."

Harvest's Energy Garden, which uses GICON's batch two-stage anaerobic digestion technology, is the largest of its kind in North America. The facility produces enough energy to power approximately 900 homes per year, and provides hundreds of thousands of cubic yards of top quality soil products to local farms, gardens and landscapes.

"Our Government is supporting innovative projects across the country and positioning Canada at the forefront of clean energy technology to help protect our environment and create high-quality jobs," said the Honourable Kerry-Lynne Findlay, Canada's Minister of National Revenue. "Projects like this not only support our local economy but also demonstrate how we can use clean technology to reduce greenhouse gas emissions."

"The City of Richmond is pleased to work with Harvest Power to manage and beneficially reuse our organic waste," said Malcolm Brodie, Richmond Mayor and Chair of the Zero Waste Committee for Metro Vancouver. "Together we are creating opportunities to reach our recycling targets while improving the soil for future generations and developing the increased use of renewable energy sources."

Harvest's services and products help reduce landfill-bound waste and greenhouse gas emissions associated with transportation while providing clean, local renewable energy and top quality soil products.

"We see an organic cycle of energy and nutrients: a pizza crust from last night's dinner gets turned into power today, and soil that grows tomatoes in tomorrow's garden," continued Sellew.

Financing for the Energy Garden was supported by a $4 million contribution from Natural Resources Canada and a $1.5 million contribution from BC Bioenergy Network. Proud supporters of this effort include BC Hydro, Metro Vancouver and member municipalities, Port Metro Vancouver, haulers, landscapers and local residents. The energy is sold back onto the grid under a power purchase agreement with BC Hydro.

Wastewater Treatment Residuals

Table 8: Energy, Environmental and Economic Benefits of Wastewater Treatment Biogas Projects in Canada

Energy	• Biogas utilization at wastewater treatment plants across Canada has the potential to capture up to 180 Mm^3/year or more of RNG. • This could produce 60MW of green electricity. • About 55% of the biosolids from the largest treatment facilities in Canada are processed in biogas systems. There is significant potential to recover more biogas at wastewater treatment plants across Canada.
Environment	• Capturing additional biogas in wastewater treatment plants across Canada could reduce GHG emissions by 2.8 million tonnes eCO^2/year or more. • This is equivalent to taking 560,000 cars off the road.
Economy	• Construction projects at wastewater treatment plants across Canada to increase energy production from biogas would generate $600 million in capital expenditures with a spin-off of $1.8 billion. • Digester construction projects would result in 1,000 direct and 3,000 indirect jobs • Digester construction projects create up to 30 construction jobs for 52 weeks per project. • Digesters create about 4 operations jobs and 1–2 maintenance jobs; development of additional digesters at wastewater treatment facilities in Canada would create 250 on-going operations jobs.

Case Study:
RNG Production at a Wastewater Treatment Plant
Hamilton, Ontario

Overview

The City of Hamilton, Ontario, (population 520,000) has been using anaerobic digesters to process sludge from its Woodward Avenue Wastewater Treatment Plant for a half-century. In 2006, it stopped flaring off most of the biogas and began using it to fuel a combined heat and power (CHP) plant that generates electricity, provides space heating and warms the digesters. More recently, it began purifying the biogas into 98 percent methane—a product known as biomethane or renewable natural gas (RNG), and identical in performance to the conventional fossil fuel—that is injected into the local pipeline system operated by Union Gas Limited.

While commonplace for decades in parts of Europe, where it is supported by subsidies in Germany, France and Sweden, biomethane production is just beginning to grow in the United States, and lags even further behind in Canada. The country's first bio-methane facility is at an agricultural digester in Abbotsford, BC. Hamilton's $4 million project is, so far, the only one in Canada based on digested solids from a municipal wastewater treatment plant.

The City was able to leverage several initiatives, including innovative planning and design as well as a shared municipal, provincial and federal government infrastructure funding to achieve environmental benefits, create revenue, validate new technology, and provide a full-scale demonstration facility for an emerging renewable biogas market in North America.

Features

- The CHP facility and the RNG purification plant are owned by the City and operated and maintained by a civic corporation known as Hamilton Renewable Power Inc.
- The City has a "wheeling" agreement with Union Gas. In this arrangement Union Gas does not pay for the biomethane; it charges the city a small fee to transport the gas on its behalf. The City then buys the remainder of its required supply by conventional means, less the amount of biomethane it has injected into the pipeline. The City also paid for the purification and injection facility, built to Union Gas' gas quality specifications, and covers its annual operating and maintenance cost.
- The CHP facility usually operates at maximum capacity, consuming 15,300 cubic meters (m3)/day of biogas and accounting for most of the current daily biogas production of 17,150 m^3.
- As biogas production rises, more will flow to the Greenlane "Rimu" purification facility. The facility, with daily capacity of 10,000 m^3 of biomethane, was sized to handle the forecasted biogas supply until 2020, but the modular design enables expansion.
- The comparative economic benefits of CHP and RNG rise and fall with the market price of electricity and natural gas, and the availability of subsidies. The two uses are complementary, since outputs can be adjusted depending upon which offered the better return.

Future Plans and Opportunities

Hamilton is growing, and a formal master planning process identified the need to increase the treatment plant's daily capacity from 108 million to 132 million gallons/day. The expansion will generate additional sludge, so more digesters and dewatering centrifuges are also planned. These changes are expected to raise biogas production by 215 percent, to a daily average of about 37,000 m^3, within 20 years.

Biogas, CHP and RNG production are all part of the City's ambitious plan to make the Woodward Avenue Wastewater Treatment plant a zero-net-energy user'. Additional plans are in place to investigate co-digestion of fats, oils and greases from the restaurant industry as a supplemental fuel source for digesters.

Biogas Association

biogasassociation.ca

Press Release

Canadian Biogas Association Calls for Policies to Develop RNG Markets in Ontario

Ottawa, Ontario (August 25, 2017) – As the voice of Canada's biogas sector, the Canadian Biogas Association (CBA) calls upon the Ontario government to create policies that support the development of RNG projects across the province.

Ontario is taking a leadership role on GHG reduction measures and action to move Ontario towards a circular, low-carbon economy. As a proven, 100% renewable technology, biogas is an immediate solution for Ontario's GHG reduction targets and can play a key role in achieving Ontario's priority energy, environmental, and rural economic policies. Renewable natural gas (RNG) produced from biogas is a versatile, low-carbon fuel that is fully interchangeable with natural gas. RNG is a clear winner for decarbonizing Ontario's natural gas supply.

Biogas and RNG development has stagnated in Ontario with a current lack of policies and regulations that encourage the development and use of this technology. To realize the powerful climate benefits of RNG, the industry needs predictable market demand and long-term revenue to attract capital investment necessary to develop new biogas projects.

CBA is advocating for policies that mandate a renewable content requirement of 2% RNG by 2025, pricing for RNG of $21/GJ on average to create sustainable biogas business models for facility developers, and funding to support innovation and opportunities to maximize benefits of the proven, low-risk biogas solution.

"The biogas industry is ready to develop RNG projects today to contribute to lower-carbon, resilient energy systems" says Jennifer Green, Executive Director of the Canadian Biogas Association "Ontario has the expertise to build more facilities with proven, low-risk technology, and to support development sustainable business models are essential."

About the Canadian Biogas Association

As the collective voice of Canada's biogas sector, the Canadian Biogas Association is developing the biogas industry to its fullest potential through capturing and processing organic materials to maximize the utility and value inherent within that material. Our members span the entire value chain of the sector and consist of farmers, municipalities, and private sector owners and operators of biogas systems, technology suppliers and consultants, financial and learning institutions, utilities, and waste industry and organic residuals generators.

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ENBRIDGE GAS INC.

Undertaking Response to ED

To provide a list of reports available internally at EGI, not restricted to those prepared by the Biogas Association, and put those on the record.

Response:

Please see the following attachments to this undertaking:

1. Renewable Natural Gas (Biomethane), Regulatory Assessment for Selected Canadian and European Jurisdictions, Final Report, Prepared for Natural Resources Canada, March 31st, 2017.
2. Biomethane Guide for Decision Makers, GreenGasGrids, the Intelligent Energy - Europe programme (contract number IEE/10/235/S12.591589), September 2013.
3. Renewable Natural Gas Technology Roadmap for Canada, Canadian Gas Association, December 2014.
4. Integrated community Energy System Business Case Study, Renewable Natural Gas the Ontario Opportunity, QUEST (Quality Urban Energy Systems of Tomorrow), January 2012.
5. Potential Production of Renewable Natural Gas from Ontario Wastes, Salim Abboud and Brent Scorfield, Alberta Innovates Technology Futures, May 2011.
6. Gas Utility RNG Activities, American Gas Association, December 5, 2019
7. Could Renewable Natural Gas Be The Next Big Thing? Yale Environment 360, July 25, 2019
8. Ontario Farmers Seeing Revenue Opportunity in Biogas Digesters, Farmtario, December 3, 2019
9. Biomethane Pre-Feasibility Final Report (Preliminary), COOP Carbone, December 2016
10. Renewable Natural Gas: Affordable Renewable Fuel for Canada, Canadian Gas Association, 2016
11. Closing the Loop, Canadian Biogas Association, June 2015

Renewable Natural Gas (Biomethane) Regulatory Assessment for Selected Canadian and European Jurisdictions

TorchLight Bioresources

2017

Renewable Natural Gas (Biomethane) Regulatory Assessment for Selected Canadian and European Jurisdictions

Final Report

Prepared for

Natural Resources Canada

March 31st, 2017

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Executive Summary

Renewable natural gas (RNG), also known as biomethane, is a bio-based fuel than can be blended with natural gas and utilized in all the same applications – space and hot water heating, industrial manufacturing such as chemicals production, electricity generation, and transportation. A primary reason for RNG's attractiveness as a renewable fuel is the ability to distribute it using the existing, extensive natural gas system. It can be injected into both distribution and transmission pipelines for delivery to large and small volume customers.

The potential of RNG to reduce greenhouse gas (GHG) emissions and diversify the energy supply in a capital-efficient manner has been recognized by many governments. Europe in particular has taken a leading role in development of the RNG industry, with Germany alone home to almost 200 projects. While Canada currently trails many nations in deployment of RNG technology and utilization of the fuel, Canada's desire to reduce GHG emissions, significant biomass resources, substantial natural gas consumption, and extensive gas network make it a potentially attractive jurisdiction for a RNG industry.

This project examined the regulatory and policy environment for RNG in five selected jurisdictions: Germany, the United Kingdom, Canada, British Columbia, and Ontario. As the two most mature RNG markets, Germany and the UK offer policy lessons for development of an RNG industry in Canada. The project examined several key considerations for RNG industry establishment and expansion, including natural gas network access, business structures and pricing, GHG performance and valuation, and policies to encourage or drive investment in the industry. There are several technology routes for production of RNG, which range from entirely commercial upgrading of biogas from anaerobic fermentation to demonstration scale methanation of syngas from woody feedstocks, but this was not a major focus of the project.

Based upon the regulatory and policy comparison between the jurisdictions, it was clear that German and UK national governments have taken the lead in progressing development of domestic biomethane industries. In contrast, Canadian governments – both federal and provincial – have provided limited policy encouragement and it has been the natural gas utilities themselves that have led development of the RNG industry. In numerous cases, the regulatory structure overseeing the natural gas utilities has been a major impediment to establishment and growth of the industry despite efforts of the utilities.

Although Germany and the UK both have large and competitive biomethane industries, the countries have used very different and contrasting policy tools to support development and encourage investment. In the UK, a Renewable Heat Incentive – akin to a Feed-in-Tariff for heat with guaranteed 20-year contracts – has been the primary policy driving development. In Germany, the ability of utilities to distribute the costs of biomethane injection across the entire German customer base has been essential. In both cases, requiring utilities to provide distribution or transmission grid access to biomethane producers in a timely, non-discriminatory, and cost effective manner has been a key policy.

Based upon interviews with Canadian natural gas utility representatives, it is clear the utilities have a strong desire to include RNG within their fuel supply. However, the notably higher cost of RNG compared to natural gas and the distributed supply nature of the fuel mean the present regulatory and policy situation in Canada and its provinces, which were designed around a homogeneous natural gas product, must be modified if RNG is to play a meaningful role in reducing GHG emissions in Canada.

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1 Introduction

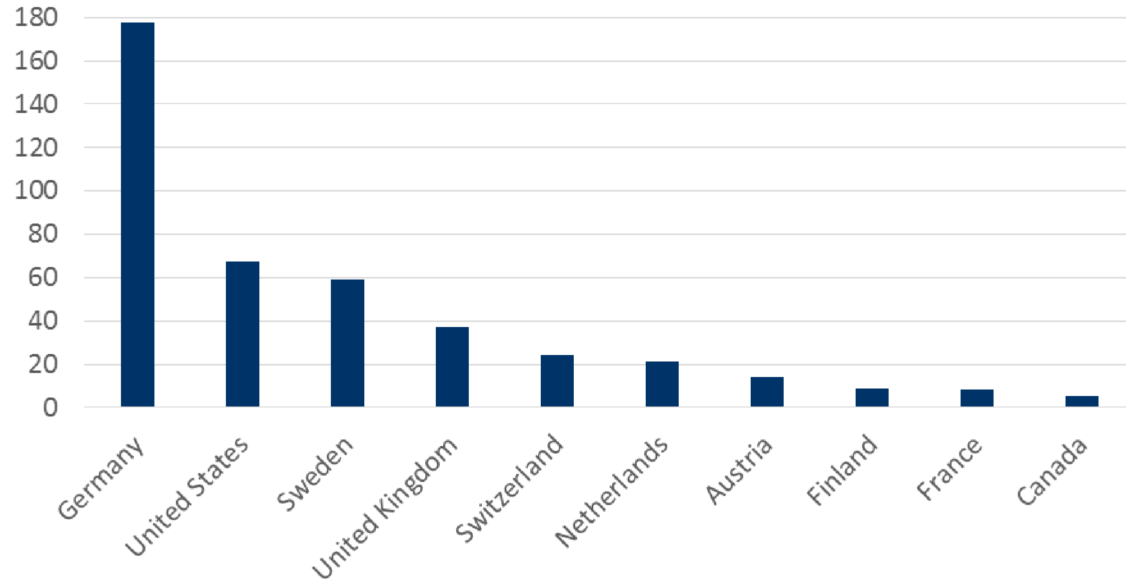
Canada has committed to reducing its greenhouse gas (GHG) emissions by 30% from 2005 levels by 2030, which requires a reduction of 220 Mt CO_2 eq from 2014 emissions of 732 Mt CO_2 eq.[1] This aggressive reduction over a short time frame will necessitate utilization of the existing energy infrastructure due to the very long lead time for infrastructure turnover. While significant attention has been paid to renewable electricity, Canada already has the third lowest electricity GHG intensity in the G20 and most provinces already have a grid GHG intensity below the lowest of the G20 nations – France.[1,2,3] Therefore, decarbonisation of non-electrical energy infrastructure – namely fuels carried by pipeline – needs to be a major priority if Canada is to meet its climate policy commitments. These include transportation fuels and Canada's major heating and industrial fuel – natural gas.

Canada is a major consumer and exporter of natural gas. It is the third largest per capita consumer of natural gas in the OECD (behind smaller markets of the Netherlands and Luxembourg) and in the G20 (behind major oil producers Saudi Arabia and Russia). In 2014, Canada consumed over 90 billion cubic meters of natural gas with an energy content, at 3.7 EJ, equal to approximately one third of Canada's total primary energy supply.[4] Canada has approximately 450,000 km of natural gas distribution pipelines and over 80,000 km of natural gas transmission pipelines.[5] It is highly unlikely that a significant proportion of this infrastructure will be stranded in the next decade, and therefore, reducing the carbon intensity of the fuel transported by pipeline is of great importance to meeting climate commitments. While there is certainly opportunity to reduce the upstream GHG intensity of natural gas recovery operations, a highly promising avenue for decarbonisation is blending renewable natural gas (RNG), also known as biomethane, with natural gas. RNG is methane (CH_4) produced from biological materials that has been upgraded to meet the specifications of the natural gas grid. It can be produced from a variety of materials via traditional anaerobic digestion processes, which generate methane rich biogas, or via thermochemical routes such as gasification followed by methanation of the resulting syngas. While the RNG industry in Canada is in its infancy, previous studies have highlighted the significant potential of RNG to reduce GHG emissions in Canada while leveraging previous natural gas infrastructure investments.[6]

2 Natural Gas Network Access

Natural gas network access is a necessity for Canada's RNG industry to move beyond niche transportation and local heating operations. The ability to leverage previous investments in natural gas infrastructure and to be blended with natural gas provides RNG producers the opportunity to access a multitude of markets, including many where gas demand far outstrips potential RNG supply. However, Canada's legislative and regulatory regime for natural gas has limited the ability of RNG producers to economically access the natural gas network – in some cases, thwarting efforts by network operators to include RNG in the gas supply. In Canada, it has been the network operators seeking to blend RNG with natural gas – as a means to diversify supply, meet the demands of environmentally-conscious customers, and access growing markets such as transportation – despite the constraints of utility regulations. This could be considered the utility-led approach. This is in stark contrast to Europe, where it has been political and legislative actions that have driven growth of the RNG (termed biomethane in Europe) market and imposed requirements on network owners and operators to provide access. This could be considered the government-led approach.

Figure 1. Renewable Natural Gas/Biomethane Plants, 2014*



*As of December 31, 2014, except United States, which is May 12, 2014

The utility-led approach in Canada is also is evident in Canadian RNG documents and presentations, which differ in approach and tone compared to European regulations, acts, and government guidance documents. Although the voluntary willingness of gas utilities to include RNG in their networks was identified as a key component of industry growth in the *Renewable Natural Gas Technology Roadmap* prepared by the Canadian Gas Association, legislative and regulatory examples from Europe indicate that a 'willingness' is not required if regulated utilities are legislated to provide natural gas network access.[6] This is not to say Canadian utilities are unwilling, but simply that in other jurisdictions that have employed a government-led approach, it has been mandates and regulated utility requirements that have led to industry growth – not entrepreneurial activities by utilities. Establishment of national biomethane targets and goals have also been a role of governments in Europe, while in Canada, it has been left to the Canadian Gas Association and its members to propose national targets – 5% RNG by 2025 and 10% by 2030.[7]

In contrast to market and physical network access conditions, general RNG quality requirements for inclusion in the natural gas network are fairly consistent across jurisdictions and do not appear to be a technical hurdle to growth of the RNG industry. The RNG quality requirements are created to ensure: 1) safety; 2) efficient network operation; and 3) equality between customers. In all cases, the aim is for RNG to meet or exceed the quality standards of natural gas. In general, there are typically four RNG characteristic requirements:

1. **Gas Safety**
   Due to a lack of odour or hue, all natural gas is odorized to enable the detection of leaks. The odorizer varies from country to country, but is often a sulphur-containing compound (mercaptans/thiols such as methanethiol). Methyl and ethyl acrylates can also be used. All RNG must be odorized prior to entering the natural gas network to ensure safety and consistency. In all jurisdictions, the natural gas network operator is responsible for ensuring RNG is odorized.

However, the permitted operator (RNG producer or network operator) of odorization equipment varies from jurisdiction to jurisdiction.

2. **Gas Purity**
   In most cases, RNG must meet the same gas purity requirements of natural gas. The purity requirements are typically included in natural gas legislation and long predate RNG industry development. For example, in the UK, RNG must meet the quality requirements established in the Gas Safety (Management) Regulations of 1996. Contaminants that have maximum values established in purity requirements can include CO_2, H_2, O_2, H_2S, N_2, H_2O (or water vapour dewpoint), and total sulphur [including mercaptans added for odorizing such as methanethiol (CH_3SH) and ethanethiol (C_2H_5SH)]. Hydrocarbon dewpoint is also used as a standard requirement.
3. **Energy Content**
   Natural gas is largely composed of methane but typically has moderate volumes of propane and butane (and sometimes longer chain hydrocarbons) included. These gases have a higher energy content than methane and therefore increase the energy content of natural gas beyond that of methane. In contrast, RNG contains only methane (with small amounts of other gases, such as CO_2) and is thus lower in energy content than a natural gas containing propane and butane. In order to ensure consistency throughout the natural gas network and equality for all customers in energy delivered, it may be necessary to add propane and/or butane (in the form of LPG) to RNG prior to injection.
4. **Interchangeability**
   The Wobbe Index (WI) or Wobbe Number (WN) indicates the interchangeability of gases, as dictated by their combustion energy output. It takes into consideration both higher heating value (energy content) but also specific gravity. As with the gas energy content, different regions have different standard Wobbe Index values which typically reflect the propane and butane content. Propane and/or butane may need to be added to the RNG prior to network injection in order to meet Wobbe Index standards. As with odorization, it is the responsibility of the natural gas network operator to ensure a consistent Wobbe Index across its network but jurisdictions vary on the role of the network operator/RNG producer in propane/butane addition.

1.1 Canada

Canada's federalist approach to natural gas regulation means each province has its own regulatory body which governs all intra-provincial natural gas lines. The National Energy Board (NEB) is the regulatory authority for interprovincial and international natural gas transmission pipelines. In addition, the NEB regulates major energy developments. The NEB promotes safety and security, environmental protection, and efficient energy infrastructure and markets in the Canadian "public interest" (a balance of economic, environmental and social interests that change as society's values and preferences evolve over time). The NEB also monitors energy supply, demand, production, development, and trade which are the jurisdiction of the federal government.

The NEB plays an important role in setting the tolling regime for transmission of gas for the largest (Group 1) pipeline companies. It regulates pipeline tolls and tariffs "so that they are just and reasonable" and to ensure "no unjust discrimination in tolls, service or facilities."[8] In some cases, transmission lines operate under a negotiated settlement regime between gas shippers and transmission line operator based upon a cost of service toll (such as the TransCanada Mainline from 2007-2011). However, the NEB can also fix tolls for transmission lines (as it did for multiyear contracts on the TransCanada Mainline in 2013).[9] The process for establishing the regime and the tolls themselves for the large pipeline companies typically involves a detailed tolls application filed by the company that owns and operates the pipeline – ideally with support of its main gas shippers (customers) established through a negotiated settlement. The tariff regulation for the smaller gas pipeline companies (Group 2) and two of the larger companies (Group 1) used a complaint-based system.[8] In other words, pipeline owners and gas shippers establish agreements themselves and the NEB only becomes involved in setting tolls when a complaint is filed.

Should an RNG project wish to connect to an NEB-regulated pipeline, it may be necessary for the NEB to play a previously unfamiliar role by mandating preferred access to pipelines for certain (i.e., RNG) producers and in ensuring the RNG injection costs are distributed throughout the system (as is the case in Germany). Given the two groupings of NEB-regulated pipelines and the absence of the NEB input on tolling rates for Group 2 pipelines, this may pose some challenges. However, there may be alternative mechanisms for this federal financial role, such as federal government incentives to producers.

The NEB would likely not be the regulator for most RNG projects as the vast majority of projects are likely to connect to intraprovincial pipelines. However, there are two potential exceptions, both of which are particularly relevant for forest-based RNG projects due to their location and likelihood of scale much larger than agriculture or municipal feedstock projects. The first is the NEB is the regulatory body for interprovincial pipelines, including Westcoast Pipeline, Alliance Pipeline, Nova Gas Transmission Line system, and the TransCanada Mainline. An RNG project connecting directly to an interprovincial (or international) natural gas transmission line would form part of the regulatory responsibility of that pipeline. Forest-based RNG projects are likely to be much larger in scale and more likely to be located in regions where the only connection is a major transmission line (vs. local distribution line). The second exception is if an RNG project is considered a "major resource project" and is subject to environmental assessment under the Canadian Environmental Assessment Act.

The NEB can potentially consider the following attributes of a project:

- Engineering;
- Environmental and socio-economic matters;
- Economics and financial matters;
- Land matters; and
- Any public interest that may be affected by granting or refusing the application.

Connection to a natural gas transmission line could technically occur at any point along the transmission line and is not restricted to compressor stations. There is no major benefit, in cost or technical ease, to connecting at the location of a compressor station.[10] In contrast to some gas distribution companies, gas transmission companies are unlikely to be involved in the biogas upgrading to biomethane. However, due to the technical and regulatory situation, it is likely natural gas transmission companies will desire (or even be required) to own and operate the biomethane injection facility. This will need to include analyzers for gas purity (e.g., H_2S, CO_2 levels) and quality, and an automatic block valve for injection cut-off in the event of biomethane not meeting required gas characteristics. It should be noted that natural gas in eastern Canada has a very high methane content (>98%) and low levels of butane and propane because the natural gas has been stripped of these higher energy content gas prior to transmission to central and eastern Canada. Therefore, addition of supplemental butane and propane will not be required.[11] This is not the case for gas in British Columbia or Alberta, where supplementation may be necessary.[10]

Two provincial regulatory regimes regarding intraprovincial natural gas distribution network access are presented below.

1.2 Ontario

In Ontario, the Ontario Energy Board (OEB) facilitates natural gas competition, transmission and distribution system expansion, and maintenance of a financially-viable industry. It seeks to "protect the interests of consumers with respect to prices and the reliability and quality of gas service".[12] In contrast, the Technical Standards and Safety Authority (TSSA) is the entity required to enforce compliance with safety standards. Safety requirements for RNG pipelines and injection will be consistent with those of natural gas and should not be a significant hurdle to RNG industry growth. In contrast, the OEB's role in pricing and the differential in cost between natural gas and RNG means the OEB will play a critical role in whether RNG becomes a viable industry in Ontario.

As identified above, the Canadian model for RNG industry growth to date has been a utility-led approach and Ontario is no exception. The OEB has not prohibited RNG producers from accessing the natural gas network but has denied preferential treatment of RNG over natural gas, thus preventing industry growth due to economic competitiveness challenges. In September of 2011, Ontario's two major gas distributors – Enbridge Gas Distribution (Enbridge) and Union Gas Limited (Union Gas) – submitted a joint "Renewable Natural Gas Application" to the OEB requesting approval of an RNG program to kick-start the industry. The application stated:

> *The purpose of this application is to establish a Renewable Natural Gas ("RNG") Program to enable the development of a viable industry in Ontario. This will allow the benefits outlined in this evidence to be realized. The benefits represent significant opportunities, including the opportunity to offer greater choice for energy consumers, and the opportunity to maximize the efficient use of biogas resources. Establishing a RNG Program now, when these opportunities are available, will ensure that these benefits are not passed over.*[14]

The OEB, as part of Ontario's efforts to deregulate the industry and create competition, prohibits natural gas distribution companies from entering into long-term supply contracts with customers and suppliers. They must purchase natural gas at market prices and pass these prices onto customers without markup. As in many jurisdictions, natural gas distributors, due to their monopoly on infrastructure and delivery, are also barred from producing natural gas (or RNG) or owning equipment to produce/extract natural gas (unless approved by the OEB). The OEB sets the transmission and distribution charges for the distributors.[12] Since RNG production costs are higher than market prices for natural gas, the gas distributors required permission to pass on the costs of acquiring RNG to customers since no legislation gave preference to RNG within the natural gas network. In addition, in order for potential RNG producers to finance facility development, long-term offtake (purchase) agreements would need to be established with utilities. Enbridge and Union Gas proposed an RNG program similar to the Ontario's electricity Feed-in-Tariff (FiT) program, with 20-year contracts. The RNG Application also proposed 1) connection procedures and capital cost contributions of RNG producers to connection costs; 2) gas quality standards; 3) allocation mechanism to ensure equitable access to gas network.[14]

In July 2012, the OEB rejected the RNG Application from Enbridge and Union Gas, stating a lack of "evidence of the technical and operational considerations of potential developers in Ontario; a rigorous cost benefit analysis; evidence on like programs in North America and elsewhere; consideration of the potential involvement of gas marketers; and the appropriate size of this program and customer acceptance of the resulting bill impacts."[15] Since that time, the Ontario Government has recognized the ability of RNG to deliver on the government's policy priorities, namely GHG reductions, and in December 2016 Ontario Energy Minister Glenn Thibeault requested the OEB consider RNG as part of Ontario's natural gas supply. However, no specifics on what "move[ing] forward in a timely manner to include RNG as a potential fuel…" constitutes.[16]

In summary, there is currently a conflict between the Ontario Government's goal to include RNG within the natural gas network and the OEB's mandate and associated limitations, including establishment of long-term contracts, on distribution companies. Without an ability to pass on the higher cost of RNG to gas consumers, which includes the capital costs of network connection, distribution companies are unlikely to offer connections to RNG producers. In addition, without a legislated prioritization for RNG connection and network capacity over natural gas, industry growth will be limited.

1.3 British Columbia

In British Columbia, the regulator for natural gas pipeline transportation is the BC Oil and Gas Commission and gas quality and safety must meet the requirements of the BCOGC. However, market and distribution utility regulation is the jurisdiction of the BC Utilities Commission (BCUC) and it is this body that is the focus for RNG access to the natural gas distribution network.

As in Ontario, the push for RNG in BC has been utility-led. In 2010, the BCUC approved a RNG/biomethane pilot program proposed by FortisBC.[17] Following approval of an exemption for biomethane and biogas producers under the BC Utilities Act, the full program came into effect in 2013.[18] It was further modified by the BCUC in August of 2016.[20] As in Ontario, the gas distributor's ability to purchase gas at above market prices has been historically limited in BC. Therefore, the BC RNG program design relied upon a consumer-pay model in which customers willing to cover the additional cost of RNG over natural gas could voluntarily sign up to have 5-100% of their gas as RNG. The BCUC established a Biomethane Energy Recovery Charge (BERC), which represented the all-in costs for RNG purchase and running the RNG program distributed amongst buyers of RNG. The BERC also included operating costs associated with natural gas network connection but the capital costs of FortisBC-owned equipment (assets) were distributed amongst all FortisBC customers.[19] In some currently-connected RNG projects, FortisBC owns the biogas upgrading equipment (to produce biomethane), the costs of which are distributed amongst all customers, while in other cases, the producer owns the upgrading equipment and the cost is worked into the BERC.[21] In both cases, the customer-pay model inherently results in utilities limiting the number and volume of RNG connections to RNG demand in the marketplace. Due to the small-scale of the RNG industry, it also leads to a large differential between consumer prices for RNG and natural gas, which in turn limits demand for RNG and hence connections. Under the FortisBC program, potential RNG producers have to apply for a connection, which is reviewed by FortisBC and can be rejected at the utility's discretion. Criteria for connection including aspects such as demonstrating "technical and business competence".[21] Terms are negotiable and reaching agreement can take in excess of 6 months. Supply agreements must then be approved by the BCUC. The incentive for FortisBC to develop and maintain the RNG program is that the BERC is higher than FortisBC's costs to acquire, process, and inject the RNG and FortisBC makes a return on capital invested.[33]

The pricing regime for RNG changed in 2016 (as described in Section 2.3), with the goal of increasing RNG demand, but the network connection approach remains the same.[20] Instead of the government or the BCUC mandating FortisBC to accept RNG into the natural gas network as a GHG reduction measure, FortisBC has discretion over which RNG projects will be connected and when. FortisBC requires a sufficient 'local' demand/load for RNG and is not required to give preferential treatment to RNG.[33] As contracts with RNG producers are negotiated on a case-by-case base by FortisBC, the utility has virtual authority over the rate of growth of the RNG industry in BC. Under current conditions where network connections are permitted only when sufficient demand exists and the significant price premium of RNG over natural gas, which limits demand, it is unlikely the RNG industry will experience rapid growth in BC. The onerous process for securing a network connection, including negotiation with FortisBC and approval of agreement terms by the BCUC, further limits industry growth.

1.4 Germany

In contrast to Canada, Germany has taken a government-led approach to biomethane industry development in order to meet the government's environmental goals. Injection into the German natural gas network started in 2006 following passage of the Gasnetzzugangsverordnung (GasNZV; Grid Access Regulation) in 2005.[22,24] Under GasNZV, biomethane producers are given priority to connect to the German natural gas network and, following an application to the network operator, the network connection must be completed by the operator within a maximum of 18 months. Pipeline capacity priority is given to biomethane over natural gas and the gas network operator must provide access to the network for injection at least 96 % of the time. In other words, network operators cannot limit the physical market access of biomethane producers by unilaterally shutting valves. While the biomethane producer is responsible for upgrading biogas to biomethane and meeting German natural gas quality standards, as established under DVGW G 260/262, it is the responsibility of the network operator to adjust the biomethane for local energy content (by adding propane or butane) and odorizing the gas.[22,23] The Network Entry Facility, which includes these gas adjustments in addition to compression, monitoring, and flow management equipment, and monitoring is owned by the network operator. The operating costs of this facility must be covered entirely by the network operator. [25] In addition, 75% of the capital costs for this facility and a network connection pipeline (up to 1 km in length) must be covered by the network operator. The biomethane producer is responsible for the other 25% of capital costs up to a maximum of €250,000. Any pipelines extending from 1-10km from the gas network must be split 75:25 for the network operator and biomethane producer (no maximum value), while pipelines beyond 10 km from the existing network must be entirely paid for by the biomethane producer.[22,23] There are no network pressure limitations placed on biomethane producers and connection is permitted for both high pressure transmission systems and lower pressure distribution systems.

Given the penalties placed on network operators for a delay in providing a biomethane producer connection to the network, the GasNZV recommends creation of a "realization roadmap" (implementation plan, which details steps for implementing the connection, as agreed upon by the operator and the biomethane supplier.[22]

The German government clearly understood the importance of network access to biomethane industry growth and this is reflected in legislation which requires regulated utilities to provide a transparent process for network connection. They must provide potential biomethane producers clear step-by-step instructions for establishing a connection. In addition, the legislation places the majority of connection costs on the network operator for distribution amongst all natural gas consumers. This removes a major barrier to biomethane project development – the uncertain and often high costs for network connection – and disincentives utilities to overcharge for connection. However, this approach does result in higher energy costs for all natural gas consumers, whether they wish to consume biomethane or not.

1.5 United Kingdom

As in Germany, natural gas network operators in the UK are required to provide access to the natural gas grid for biomethane producers. Condition D12 of the Gas Transporter License (GTL), which came into effect on April 1, 2007, is entitled "Requirement to offer terms for the provision of gas entry points".[26] Provisions of Condition D12 include the date when the licensee shall allow gas to be introduced into the pipeline system, the maximum flow rate available from time to time on the pipeline system, the requirement of the applicant to pay the licensee's reasonable costs incurred and a reasonable element of profit, and dispute terms. A holder of a GTL (i.e., natural gas network operator) must offer terms not more than 6 months after receipt of an application and must publicly publish those terms no later than one month from the date on which it enters into a gas entry agreement.[26] Under the condition, all costs association with connection to the natural gas network are the responsibility of the biomethane (or natural gas) producer.

In the UK, the Office of Gas and Electricity Markets (Ofgem) is responsible for economic regulation of the gas market while technical network operation requirements are established under the Uniform Network Code (UNC). The UNC is a set of guidelines for all gas industry participants and requires biomethane producers to enter into a Network Entry Agreement (NEA) with a Gas Transporter prior to injecting into the network. Specifically, the UNC "is the operating regime around which the competitive gas industry revolves. It is a legal and contractual framework to supply and transport gas. It has a common set of rules for all industry participants, which ensure that competition can be facilitated on equal terms. The UNC is managed by the Joint Office of Gas Transporters. Ofgem is the regulator for Britain's gas and electricity industries. Its role is to promote choice and value for all customers."[29]

Under UK regulations, GTL holders (e.g., National Grid) must operate or monitor the Network Entry Facility for natural gas/biomethane injection. The construction of the Network Entry Facility is a competitive activity and can be performed by the GTL holder or by a third party according to specifications (Functional Design Specifications) described by the GTL. The Network Entry Facility ensure the biomethane quality meets the Gas Safety (Management) Regulations of 1996 and the energy content complies with The Gas Calculation of Thermal Energy Regulations of 1996.[30] Network Entry Facilities, as with those in Germany and other jurisdictions, include remotely operated valve (ROV) and telemetry units (RTU) to ensure these gas standards are maintained. Whether the Network Entry Facility is owned by the biomethane producer or the GTL holder, the ROV and RTU are owned and operated by the GTL holder.[27] These units can be purchased by the biomethane producer but must be transferred to the GTL holder.

Under the regulatory framework for gas in Britain, a GTL holder cannot also hold a Gas Shipper license. Gas Shippers make agreements with gas suppliers/producers to bring gas into the system, GTL holders to transport the gas, and Gas Suppliers to sell the gas. Gas Suppliers in turn sell the gas to consumers. In order for biomethane producers to inject gas into a British gas distribution or transmission network, they must first have a sales agreement with a licensed Gas Shipper.[30]

While the UK mandated GTL holders to provide grid access (and agreement terms) to methane producers in 2007, and the profit for the GTL holders on this activity was limited, the inability to spread biomethane production and network connection costs over a broad customer base meant five years passed between the institution of condition D12 and the commissioning of the first biomethane plant in 2012. It was the Renewable Heat Incentive (as discussed in *Section 2.5*), enacted in 2011, that provided financial incentives for biomethane network injection and created the conditions required for economically-viable network connections.[31]

2 Business Structures and Pricing

RNG, like natural gas, is a highly-flexible fuel that can be used for heating, transportation, electricity production, and as a feedstock for chemicals (e.g., methanol, hydrogen, nitrogen fertilizer). This has meant jurisdictions have used a broad variety of measures to support the development of a domestic RNG industry, with policies and regulations reflecting the specific needs and goals of each jurisdiction. First among these goals has typically been a desire to reduce GHG emissions, although improving energy security by sourcing domestically-produced gas and supporting rural communities and businesses have also been important drivers. The sector of priority for GHG reductions has been partially dictated by the GHG profile of each jurisdiction. In order to make 'best use' of RNG from a GHG perspective, a sectoral comparison GHG impact of RNG use must be completed and updated over time. For example, Sweden has prioritized the transportation market for RNG due to the already-low GHG profile of its electricity and heat sectors (in addition to a low natural gas penetration rate compared to many other European countries). This is in contrast to Germany, which has prioritized electricity generation and the UK, which has prioritized heat markets. When considering development of the RNG industry in Canada, the alternative uses for biomass feedstocks need to be taken into consideration. This is particularly true for solid lignocellulosic feedstocks, such as woody biomass, which can be converted into a multitude of solid, liquid, and energy products. For example, a policy that prioritizes electricity generation (e.g., a Feed-in-Tariff) may limit the growth of the RNG sector due to competition for feedstocks and project capital.

The business structure and contracting for RNG will reflect the policies and incentives instituted in each jurisdiction. Based upon the review of gas network access approaches (above), network access alone has been insufficient in all jurisdictions to kick-start the RNG industry. This is due to economic competitiveness challenges of RNG relative to incumbent natural gas. The following assessment of RNG incentives, support programs, and pricing regimes describes some of the possible approaches for encouraging growth of a Canadian RNG industry, but should not be considered a definitive assessment of all possible options.

2.1 Canada

Under the federalist system, provinces are largely responsible for regulation of heat and electricity markets. This has meant the federal government's approach to supporting renewables in the heat and electricity sectors has been supplemental to provincial government efforts. Much of the support for renewables that could be considered relevant for the RNG industry has come in the form of grants for capital expenditures and technology commercialization. However, these grants are typically one-offs and do not support long-term growth of the sector. Unlike many European nations, Canada has not established national policies or regulations that could be considered supportive of RNG.

The federal government has played a more active role in the transportation sector with establishment of the Ethanol Expansion Program in 2003 to support commercial facility buildout, the ecoENERGY for Biofuels program in 2008 to provide volume-based support for biofuels production, and the Renewable Fuels Regulations of 2010 (SOR/2010-189). The Renewable Fuels Regulations requires renewable content be included in the gasoline and diesel fuel pools at levels of 5% and 2% respectively, the costs of which are integrated into the consumer prices. However, neither the Renewable Fuels Regulations nor the ecoENERGY for Biofuels program provided opportunities for potential RNG producers as they were limited to liquid renewable fuels only. A small (<$1M) ecoENERGY Alternative Fuels program provided support to kick-start natural gas-based transport fuel supply hubs but there was no carve out for RNG.

In November 2016, the federal government announced the country would work with the provinces and territories to establish a national clean fuel standard with the goal of reducing annual GHG emissions by 30 Mt CO_2 eq by 2030. The government announced the clean fuel standard "would be flexible, and it would promote the use of clean technology, lower carbon fuels, and promote alternatives such as electricity, biogas, and hydrogen." Although transportation has been targeted as a key sector for GHG reductions, it appears, based upon a recently released discussion paper, that building and industrial sectors are also going to be included. Consultations are ongoing, but it is anticipated that the clean fuel standard will be a key federal government tool for supporting growth of the RNG sector in the near term.

Gas transmission companies are not involved in retail sales of gas to small volume customers. Transmission companies are paid for transportation of gas and are not typically the counterparty for gas sales. Gas producers must establish an agreement with a gas buyer/consumer, with the gas transmission companies paid a toll. Therefore, RNG producers connecting to the gas transmission system will need to establish a purchase agreement with one or more buyers prior to contracting with a gas transmission company.[10] Whether or not a supplementary payment system for injecting RNG into the transmission system will be a possibility remains to be seen.

2.2 Ontario

The current regulatory framework in Ontario does not permit growth of a significant RNG industry. Despite the provincial government expressing support for RNG, the mandate of the Ontario Energy Board to ensure low cost energy without consideration for environmental attributes prevents utilities from including RNG within the gas supply. This is in contrast to the Independent Electricity System Operator (IESO), which, as a crown corporation, is directed by government to consider environmental attributes in addition to system reliability and competitive pricing for electricity. This dichotomy creates a disadvantage for the RNG (and the broader gas industry) relative to the electricity industry when seeking to deliver energy products with attractive environmental attributes but at a higher cost than fossil fuel incumbents.

The three main hurdles faced by Enbridge and Union Gas to inclusion of natural gas in the pipeline in Ontario are: 1) a restriction on offering long-term offtake agreements to RNG (or natural gas) producers due to a requirement to purchase gas a market prices; 2) the inability to pass the higher acquisition cost of RNG (as compared to natural gas) onto customers; and 3) a limitation on owning equipment involved in the production of RNG (or natural gas) such as the network entry facility for RNG injection.[32] The only way that the RNG industry could develop in Ontario without modifying the utilities' restrictions, as determined by the OEB, would be for third-party gas marketers (as per Gas Suppliers in the UK) to purchase the RNG from producers and sell to customers, using the gas network only for transport. However, unlike the UK, where gas network operators cannot also be Gas Shippers, gas network operators in Ontario can sell directly to customers. This means Gas Marketers would have to price gas higher than Enbridge or Union Gas if they wanted to include RNG in their offering. While there may be niche opportunities (e.g., the Bullfrog Power model of electricity marketing, where consumers pay a premium for positive environmental attributes of their energy), broad market adoption of RNG would be unlikely.

Under Enbridge and Union Gas' joint Renewable Natural Gas application in 2011, the utilities requested establishment of a framework for offering 20-year RNG supply contracts with similar rules to Ontario's Feed-in-Tariff system.[14] Given the public backlash to this system, the utilities are currently considering a competitive bidding system. Under the 2011 framework, different prices would be offered for landfills and anaerobic digestion plants and modified depending upon scale. The higher cost for RNG acquisition would be distributed across the entire rate base, with the total RNG supply capped at 2%. It was estimated by the utilities in 2011 that a 2% RNG blend would increase the cost of gas to the average customer by $18 per year. Under the proposal, customers could opt out by purchasing gas from a gas marketer. The utilities also proposed that they be permitted to own the network entry facility for RNG injection and, ideally, from their perspective, the biogas upgrading facility (to RNG) as well.[14]

Ontario's renewable energy policies over the past two decades have prioritized electricity, and to a lesser extent, transportation. The Feed-in-Tariff program, launched by the Ontario Power Authority in 2009 (and which built upon the earlier Standing Offer Program), provided renewable electricity generators with 20-year power purchase agreements at fixed rates. Biogas-generated electricity was included as an eligible technology in the FiT program and gave rise to over 60 biogas electricity projects. However, no similar program exists for RNG and Ontario is home to only one RNG project at present. Although the FiT program is still accepting applications for biogas projects during limited windows, the project size is capped at 500 kW, project criteria have become more stringent, and it is now a competitive process with limited capacity availability. Therefore, it is likely a reasonably attractive RNG program to support pipeline injection would not face significant competition for projects and feedstocks from the electricity sector in Ontario. Certainly from a forestry sector perspective, the FiT program is now unattractive due to the limitation on project capacity and the economies-of-scale required for financially-competitive biopower projects.

2.3 British Columbia

As with Enbridge and Union Gas in Ontario, FortisBC in British Columbia sought to showcase the utility's ability to reduce GHG emissions using existing infrastructure via the blending of RNG with natural gas.[33] This contrasts with an emphasis on electrification (of heating, transportation) contained within BC's Clean Energy Act of 2007. Support for RNG also provided FortisBC an opportunity to participate in transportation markets with RNG/natural gas blends. The full FortisBC RNG program was launched in 2013 with a user-pay system in which the full cost of FortisBC RNG acquisition and program management was required (by BCUC) to be recovered by the Biomethane Energy Recovery Charge (BERC).[18] Only customers purchasing RNG were charged the BERC. The capital and operating costs for

RNG facility equipment owned by FortisBC were distributed amongst all customers. FortisBC, unlike Enbridge and Union Gas, is permitted to enter into long-term agreements and was able to sign 15-20-year offtake agreements with biomethane/biogas producers. These long-term offtake agreements with a large utility have allowed RNG producers to secure financing for their facilities.[18,33]

While offtake agreements with RNG producers were near competitive with market natural gas acquisition cost during the pilot program design period (pre-2010), the precipitous drop in natural gas prices and an increase in costs for RNG supply (from new producers) meant the FortisBC customer price differential between natural gas and RNG became very large. FortisBC's highest cost supply of RNG is over $15/GJ, while natural gas prices have gone below $2/GJ.[33] Due to this price differential, demand for RNG was limited and major customers such as UBC balked at the price. In order to increase demand, FortisBC applied to the BCUC in the fall of 2015 to switch from a full cost recovery model to a fixed premium pricing model for RNG.[20] Under this model, RNG consumers pay $7/GJ above the market price for natural gas, with long-term contract customers receiving a $1/GJ discount from this rate. The difference between the RNG acquisition cost and the BERC + natural gas commodity price is distributed amongst all FortisBC customers.[20] Despite the modified pricing model now in operation in BC, evidence from Europe (e.g., Germany) suggests it is unlikely that the industry will experience rapid growth without an even broader distribution of the costs for RNG across the rate base.

As the program is currently designed, FortisBC seeks to align RNG supply and demand. Approximately 40% of RNG production is used by <10 commercial customers, while the remaining 60% is distributed amongst 7,500 customers.[33] Given FortisBC serves 1.1 million customers, this is a 0.7% customer adoption rate. It is an entirely voluntary approach and the importance of major customers such as the University of British Columbia, who can monetize environmental attributes via marketing and branding, cannot be overstated. FortisBC currently purchases biomethane or biogas (for upgrading in FortisBC-owned facilities) from four suppliers – two of which are landfills and two of which are agricultural-based anaerobic digestion systems.[34]

FortisBC requires each potential RNG supplier to provide complete clarity on financial projections and reviews those projections for accuracy and assumptions. Securing an offtake agreement with FortisBC requires a negotiation process which can take longer than 6 months and then the agreement must be approved by the BCUC before coming into force.[21] This process means that each RNG producer receives a different rate from FortisBC. In addition, potential producers must prove the worthiness of their proposed (commercial) technology and the technical and business expertise of their team.[35] FortisBC can also place other constraints upon RNG producers. This is dramatically different than Europe.

British Columbia is also home to Canada's first Renewable and Low Carbon Fuel Standard (LCFS). As with the federal Renewable Fuel Regulations, the first part of the BC regulation establishes renewable fuel content standards for gasoline and diesel. However, the second part requires fuel suppliers to progressively decrease the average carbon intensity of their fuels to achieve a 10% reduction in 2020 relative to 2010.[36] Under this low carbon fuel requirement, RNG can be utilized as a compliance fuel – whether it is injected into the natural gas network initially or not. This means that RNG producers can potentially sell RNG directly to customers without reaching a negotiated agreement with FortisBC.

BC Hydro, the British Columbia electricity utility, has a Standing Offer Program for Independent Power Producers that includes generation of electricity from biomass.[37] However, the current price is too low to incentivize development except for very large projects with economies-of-scale. BC Hydro held two

Bioenergy Calls, Phase I in 2008 and Phase II in 2010, and awarded eight power purchase agreements in total.[38] Most of these were to forestry companies who were seeking to generate electricity from mill and forest residues. All indications are that BC Hydro is focused on developing the Site C hydroelectric dam at present and will not be seeking to procure large amounts of biopower in the near future. However, due to the Mountain Pine Beetle infestation and the resulting reduction in sawmill output, competition from existing biomass CHP facilities for woody feedstocks should not be underestimated by potential RNG producers.

2.4 Germany

The primary mechanism for supporting biogas projects in Germany has been the electricity Feed-in-Tariffs, as mandated under the Renewable Energy Act (Erneuerbare Energien Gesetz/EEG).[39,41] Biomethane is only eligible for the prescribed 20-year FiT contracts if the projects are CHP and include 100% heat utilization. In other words, heat demand must dictate the project scale, with electricity FiT revenue providing a financial incentive for development and operation. Under this program, biomethane is injected into the natural gas grid and then utilized for CHP generation at a site distant from its production. The natural gas grid permits the transportation of biomethane from a producer to a location where there is demand. The FiT rate is dictated by plant scale and by feedstock (landfill vs. anaerobic digestion).[40] No allowance is made for gasification-based RNG generation. The prioritization of biogas utilization in the electricity sector is partially due to the continued operation of coal-fired power plants in Germany and a relatively high GHG intensity of electricity, especially when compared to jurisdictions such as Ontario or British Columbia.[42,2]

As described in Section 2, German gas network operators must cover 75% or more of the network connection capital costs and 100% of the operating costs for biomethane project grid connection facilities. Under the Gasnetzentgeltverordnung (GasNEV; Gas Network Tariff Regulation), which was implemented in 2005 and most recently revised in 2013 (to take effect in 2014), all costs incurred by network operators for biomethane grid connections must be reported to gas transmission system operators and then recovered from the gas shipper community.[43] The gas shippers charge customers a biogas neutrality charge, to cover the costs incurred by network operators, which is consistent throughout Germany for all customers on an energy unit basis. In addition to avoiding the costs associated with network injection, German biomethane producers injecting into the distribution system receive 0.7 Euro cents/kWh for forgoing the use of the German gas transmission system.[23,25]

Although there is no renewable heat incentive or heat-based FiT, Germany does employ a renewable heat standard to encourage development. The Renewable Energies Heat Act (Erneuerbare Energien-Wärmegesetz / EEWärmeG) requires 14% of Germany's heat demand to be met by renewable resources. Buildings built after 2008 must also utilize renewable heat sources or employ high energy efficiency designs, including extensive insulation.[41,44]

In the transportation sector, Germany instituted the Biofuel Quota Act (Biokraftstoffquotengesetz / BioKraftQuG), a renewable fuel standard, in 2007. It requires that the average biofuel blend in the transportation fuel pool be a minimum of 6.25% (as of 2010) on an energy basis, with an increase to 7% by 2020.[41,45] Germany must also abide by the EU Renewable Energy Directive (RED) of 2009, which requires 10% of all energy consumed in the transportation sector to be sourced from renewable resources.[46] RNG is considered an acceptable compliance fuel for both BioKraftQuG and the EU RED, although BioKraftQuG required a revision in 2009 from the original text in order for this to be the case.

Based upon evidence from the German policy approach, it is clear a biomethane/RNG industry can be developed in the absence of a renewable heat incentive or feed-in-tariff-like program. However, renewable fuel/energy standards or incentives for electricity and/or transportation markets are required. In any case, long-term agreements and policy certainty are necessary for developers to secure project financing.

2.5 United Kingdom

Although the UK has required Gas Transport License (GTL) holders to provide and prioritize biomethane gas network connections since 2007, it was not until the UK Renewable Heat Incentive (RHI) was introduced in 2011 that biomethane producers began to develop and commission projects.[31] The RHI is a broad heat support policy which goes beyond biomethane and includes heating with wood pellets, agriculture residues, other biomass materials, heat pumps, and solar thermal. The program is divided into domestic and non-domestic components; biomethane is included in the latter. Anaerobic digestion projects are eligible for RHI support but landfill gas is not. The RHI, which was amended in 2015, provides a guaranteed 20-year tariff rate for biomethane injected into the grid with payments made to biomethane producers on a quarterly basis by HR Treasury (i.e., tax payers). The tariff is calculated on the net energy content of the injected biomethane. Natural gas or other fossil fuel inputs used to produce the biomethane are discounted from the gross energy of injected biomethane.[47]

The RHI launch tariff price for biomethane injection was set at 7.71 pence/kWh or C$0.1234/kWh (C$34.28/GJ) for all volumes. However, the tariff has been reduced throughout the life of the RHI program and volume-based bands were introduced to favour smaller projects. The RHI tariff for biomethane injection for projects connecting to the gas network post January 1, 2017 stands at 3.89 pence/kWh (C$0.06224/kWh or C$17.29/GJ) for the first 40,000 MWh, 2.29 pence/kWh (C$0.03664/kWh or C$10.18/GJ) for the second 40,000 MWh, and 1.76 pence/kWh (C$0.02816/kWh or C$7.82/GJ) for remaining production.[48] The RHI tariff for biomethane is in addition to the commodity price of the gas supplied.

The UK has a number of other policies which influence the growth of the biomethane sector. As in Germany, the UK has a Feed-in-Tariff for renewable electricity produced from biogas (and other renewables, such as wind and solar) for projects up to 5 MWe.[49] In addition to the Feed-in-Tariff, the UK employs a renewables electricity standard called the Renewables Obligation, which places an obligation on UK electricity suppliers to source an increasing proportion of the electricity they supply from renewable sources.[50] While the Feed-in-Tariff is focused on small, distributed projects, larger generation projects are typically developed with the RO in mind. The RO revolves around the use of tradeable Renewables Obligation Certificates (ROCs), which enable electricity suppliers to prove compliance with the RO.

Biomethane is an eligible compliance fuel under the UK's Renewable Transport Fuel Obligation. As with the RO, the act requires fuel suppliers meet renewable content standards on a percentage basis. In the case of the RTFO, fuel suppliers can show compliance via ownership of Renewable Transport Fuel Certificates.[51] Under the rules of the RFTO, biomethane produced from waste feedstocks receives twice the number of certificates per unit of fuel as biomethane produced from energy crops.

Given the multitude of potential uses of biomethane and support schemes, the UK relies upon the Green Gas Certification Scheme to track biomethane through the supply chain (contractual rather than physical) and prevent double-counting of registered biomethane. The Green Gas Certification is operated by Renewable Energy Assurance Ltd., a subsidiary of industry organization Renewable Energy Association.[52]

3 Greenhouse Gas Emissions Quantification

3.1 Overview of Greenhouse Gas Considerations

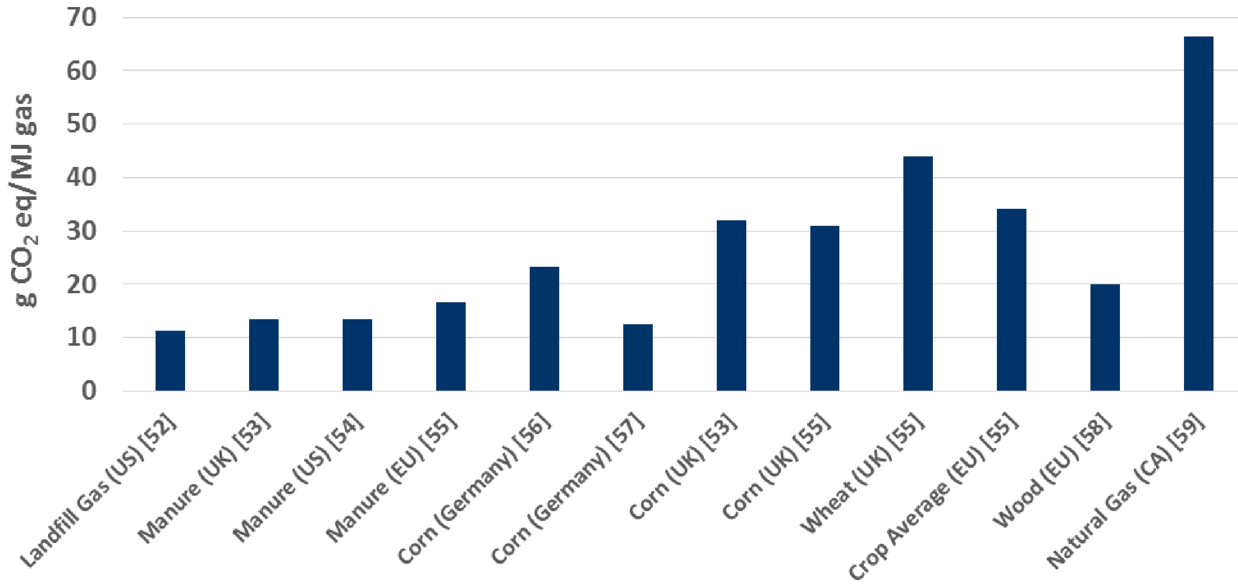
The GHG impacts of substituting natural gas with RNG are highly dependent upon the business-as-usual emissions of the feedstock used to produce the biogas, the emissions associated with production and preprocessing of the feedstock for biogas use, and the biogas upgrading process. In some cases, the business-as-usual management operation for RNG feedstocks results in atmospheric release of methane (e.g., animal waste management, landfill gas). Avoiding these emissions results in a GHG reduction beyond that achieved by avoided natural gas combustion emissions. Since methane has a global warming potential (GWP) 25 times that of CO_2, the GHG benefit of avoided methane emissions can be significantly greater than that provided by avoided natural gas combustion emissions. In addition, the potential life cycle GHG reduction achieved by substituting RNG for natural gas depends upon the production, processing, and transportation of the natural gas itself. For example, fugitive methane release can vary significantly for source to source.

RNG, like other forms of bioenergy, is not a 'carbon neutral' fuel on a life cycle basis. Fossil fuels are typically used in the production of RNG, whether that is in trucking of feedstocks, natural gas used for process heat, or fossil fuel-generated electricity used in biogas production and upgrading processes. However, in most GHG accounting systems, the actual CO_2 emissions from RNG combustion are discounted (zero rated) as the carbon in those emissions was extracted from the atmosphere by biological processes. Unlike fossil fuels, there was no net addition to the biosphere carbon pool.

The variability in GHG performance of different RNG producers means life cycle assessment is a critically important tool for policies such as the California or BC Low Carbon Fuel Standards, which require fuel distributors to reduce the GHG intensity of the fuels they sell. For fuel producers to be eligible for credits under these standards, complete and certified LCAs need to be completed. These LCAs are also ultimately necessary for fuel distributors to prove compliance with the applicable standard. To showcase the variability in LCA performance of biomethane, a number of results from academic, industry, and government studies are presented in Figure 2.

The flexibility of RNG as a fuel for heating, electricity generation, transportation, and as a chemical feedstock means that policies and programs pricing carbon or providing incentives for renewables generation need ensure accurate tracking of biomethane production, transportation, and use are achieved. In addition, schemes that prioritize decarbonisation of one sector (e.g., low carbon fuel standards for transportation) need to consider the potential impact on RNG supply and competitiveness of other sectors to decarbonize. As an example, a high Feed-in-Tariff rate for electricity generation using RNG (or biogas) in a jurisdiction with a low grid GHG intensity factor could limit the ability of the transportation sector to decarbonize.

Figure 2. The Life Cycle GHG Emissions of Various RNG Sources



3.2 Treatment under Carbon Pricing Schemes

The typical methodology to ensure the GHG impacts of RNG are monetized is to exempt (or zero-rate) RNG from carbon pricing mechanisms such as carbon taxes and cap-and-trade. In BC, the Ministry of Finance issued a Tax Bulletin to provide instructions and clarity on how biomethane (RNG) would be handled.[61] Under BC law, RNG is considered 'carbon neutral' and not subject to the carbon tax. If a carbon tax is charged (as part of a blended sale), biomethane credits, generated under the rules of the Biomethane Credit Program, can be used for reimbursement of the carbon tax paid proportional to the percentage of biomethane blended with natural gas. In other words, "the credit is equal to the carbon tax payable on the specified volume or percentage of biomethane".[61]

As the price of carbon increases, a carbon tax/cap-and-trade exemption for RNG will improve the competitiveness of the fuel relative to non-exempt natural gas. However, as discussed above, the production and combustion of biogas and biomethane can also result in avoided methane emissions associated with uncovered stockpiling or landfilling of feedstocks. In order to monetize these emissions, which can be larger than natural gas avoidance due to the high GWP of methane, a GHG credit offset system is required. Alberta provides a good example of a well-developed offset system and several protocols have already been approved that are applicable to avoided methane emissions. These include Anaerobic Decomposition of Agricultural Materials, Landfill Gas Capture and Combustion, and Energy Generation from the Combustion of Biomass Waste.[62] A critical aspect of claiming the GHG offset credit for avoided methane emissions is establishing a defendable baseline that includes release of methane into the atmosphere.

Offset systems can work in conjunction with either carbon tax, as implemented in BC, or cap-and-trade, as deployed in Ontario and Quebec, systems. Tradeable offsets are typically a core component of cap-and-trade schemes. They can be essential to meeting aggressive GHG reduction targets – particularly for industries that have limited means of reducing GHG emissions (e.g., steel production) via efficiency or fuel switching. However, under carbon tax schemes, additional legislation beyond a straight carbon tax applied to fossil fuels, is typically required. In BC, many offsets are associated with the BC government's legislative requirement to ensure a carbon neutral public sector. In the future, they may play a large role in the government's carbon intensity goals for the emerging LNG industry.[63] Differences on the pricing of offsets may have a notable impact on the rate of RNG sector development between provinces.

The life cycle GHG performance of RNG is typically a key consideration for eligibility as a renewable fuel. The most common method of determining eligibility is a minimum GHG performance requirement. As an example, the UK Office of Gas and Electricity Markets (Ofgem) provides an online Biomass Carbon Calculator so producers can determine the eligibility of their project for Renewable Heat Incentive and Renewables Obligation programs. To be eligible for the Renewable Heat Incentive, biomethane must have lifecycle GHG emissions equal to or less than 34.8 g CO_2 eq/MJ biomethane (as measured on the net calorific value). Supplemental gases added to the biomethane (butane, propane) to boost its energy content are not included. To be eligible for the RO program, gaseous biomass fuels used to produce electricity must have a GHG intensity of 66.7 g CO_2 eq/MJ electricity or lower. This drops to 55.6 g CO_2 eq/MJ electricity in 2020 and 50.0 g CO_2 eq/MJ electricity in 2025.[65]

GHG performance is also indirectly considered by systems that price the net RNG production (and typically grid injection) from a facility. Natural gas or other energy used to produce RNG is deducted from the gross energy value of the RNG injected into the pipeline under the UK's Renewable Heat Incentive. Without this deduction, producers may be incentivized to use natural gas (or even coal in the absence of carbon pricing) for thermal energy or other applications at the production site.

Some jurisdictions, such as Alberta, the UK, and the EU, have also established minimum GHG performance criteria for transportation biofuels to be considered 'renewable' and compliant under renewable content requirements. The criteria is usually a percentage reduction relative to fossil fuel baseline on a fuel energy basis. These cut-offs have historically been quite low (e.g., 25% relative to gasoline or diesel in Alberta),[66] but are becoming increasingly more stringent. For example, the EU and the UK required sustainable biofuels to have a GHG intensity 35% below baseline fossil fuel comparator. This performance requirement has now been increased to 50% (2017) and will increase again to 60% in 2018 (on biofuel from new facilities). These levels are equivalent to 41.9 and 33.5 g CO_2 eq/MJ respectively. Only fuels that meet this requirement can receive government support or count towards national renewable energy targets.[67]

A challenge could arise when GHG reduction performance relative to a fossil fuel baseline, as used for renewable fuels in the transportation sector, is applied to RNG grid injection. In some cases, RNG may not provide a sufficient (e.g., 60%) GHG reduction relative to the fossil fuel baseline because natural gas is already much lower in carbon intensity than gasoline or diesel. As an example, the Netherlands requires a 60% reduction in life cycle GHG reduction relative to natural gas at 69.0 g CO_2 eq/MJ. This means a maximum intensity of 27.6 g CO_2 eq/MJ, which is lower than the average crop-based RNG of 34.0 g CO_2 eq/MJ.[68] Therefore crop-based RNG is typically not viable in the Netherlands. It is important to consider the GHG intensity of the fossil fuel baseline before establishing performance requirements that may not be reachable.

3.3 Ownership and Transfer of Fuels and Credits

Due to the blending of RNG with natural gas in pipelines, it is important to track ownership and consumption of the RNG. As previously identified, the UK uses the Green Gas Certification Scheme to track biomethane through the supply chain (contractual rather than physical) and prevent double-counting of registered biomethane.[52] For natural gas distributors such as FortisBC, tracking is a relatively simple accounting procedure. It is when multiple sales occur within a supply chain that a centralized, independent tracking system becomes more imperative.

A certificate of sustainability must be generated in cases when RNG is being used to meet renewable content obligations and the RNG is transferred from RNG producer to gas transporter or shipper and then to gas consumer. In carbon pricing systems, such as cap-and-trade, the GHG performance of that RNG must be included in the certificate of sustainability in order for end consumers to prove their performance and compliance with carbon reduction schemes. As identified above, BC has developed a Biomethane Credit Program to ensure carbon tax is not unnecessarily applied (or reimbursed where appropriate) to biomethane.

Currently all RNG-specific regulation in Canada is under provincial jurisdiction and the RNG is consumed in the same province it is produced.[32] However, transmission system-connected RNG projects and general growth of the RNG industry in Canada will likely necessitate the transferability of both RNG ownership and the certificates of sustainability across provincial boundaries. A mechanism for doing this has not been established and provincial programs designed to encourage development of the RNG industry need to take into account the ability of RNG to cross borders using existing natural gas infrastructure. The federal government may need to play in role establishing a national RNG registry for tracking RNG production and consumption. This would become very important if there were significant differences between provinces on RNG policy (e.g., some supportive, some not) but a desire to maximize total RNG production, utilizing locally-available feedstocks, and consumption in Canada. The U.S. Renewable Fuel Standard and its Renewable Identification Number (RIN) program for tracking renewable fuels provides a good example of a national system that takes into consideration sub-national (i.e., state) differences.

3.4 Potential GHG Reductions in Canada

There have been several estimates of the potential for RNG to reduce emissions in Canada. In 2010, the Alberta Research Council (ARC; now Alberta Innovates) and the Canadian Gas Association estimated the ultimate annual RNG potential from residues and wastes was 36,800 Mm^3.[69] This estimate included production via both anaerobic digestion (16% or 5,888 Mm^3) and gasification + methanation (84% or 30,912 Mm^3). A report prepared by Kelleher Environmental in 2013 for the Canadian Biogas Association estimated the national annual RNG potential to be 2,420 Mm^3.[70] However, this estimate only included 'wastes'; crops and forest resources were not considered. If only these feedstocks were considered in the ARC report, the estimates would be comparable. To put these numbers in context, Canadian consumption of natural gas in 2014 was slightly over 90,000 Mm^3. Based upon the ARC report, it is clear forestry and agriculture crop residue feedstocks processed via gasification have the largest ultimate potential for RNG in Canada.

The Alberta Research Council report estimated the potential GHG reduction to be 108 Mt CO_2 eq while the Canadian Biogas Association estimated it to be 37.5 Mt CO_2 eq (by comparison Canada's GHG emissions totalled 732 Mt CO_2 eq in 2014).[1,69,70] The reduction per m^3 RNG is therefore calculated to be

2,935 g/m^3 for the ARC report and 15,495 g/m^3. By comparison, the life cycle GHG emissions of natural gas in Canada have been estimated to be 60-70 g CO_2 eq/MJ (2,238 – 2,611 g CO_2 eq/m^3) depending upon source.[71] Therefore, while both the ARC and CBA reports inherently assume avoided methane emissions in their calculation, the CBA figure is highly aggressive and would need to assume anaerobic breakdown and uncontrolled methane release for a high percentage of the biomass material.

4 Investment and Support for Sector Development in Canada

In most cases, government programs and policies have played a critical role in establishment and expansion of renewable energy sectors. Canada is no exception and the growth of wind, solar, biogas, and biofuels industries have relied upon government involvement in order for these energy sources to compete in the marketplace with larger, established energy rivals. As described in the previous sections, a variety of policy and regulatory approaches have been employed by governments to ensure RNG producers have natural gas network access and can develop and operate economically-viable projects. In all cases, policies and regulations have had to either modify/amend existing natural gas network and market regulations or be designed with these regulations in mind. The following sections describe options for supporting RNG projects directly (capital support and technology development support) and for creating market and regulatory conditions attractive to private capital.

4.1 Direct Capital Support

RNG production using anaerobic digestion-derived biogas or landfill gas is commercial technology and does not require technology development support in order for the industry to grow. It is the market, policy, and regulatory hurdles that are currently inhibiting growth of the industry beyond a few niche projects. Direct capital support and/or loan guarantees by government can play a role in improving the economic performance of RNG producers, although historically, these policy tools are reserved for first-of-kind plants or uncompetitive markets (e.g., remote communities). Direct capital supports are now rarely used by European countries to support biomethane projects due to the competitiveness of the landscape and the other policy instruments that can be used to support broader sector growth. Direct capital supports typically entail choosing ‘winners and losers’ which may not lead to optimal market outcomes.

In Canada, it has been first-of-kind projects that have received most direct capital support in the bioenergy sector, although programs such as the Ethanol Expansion Program have supported multiple commercial facilities to encourage capital build-out.[72] It may be that direct capital support and/or loan guarantees will be required to drive development of first-of-kind forest feedstock-based RNG (e.g., gasification & methanation) projects. Several biogas and biomethane producers have received direct capital supports from provincial and/or federal government funds under the premise of jurisdictional first-of-kind (i.e., not technology development) establishment. These include support from the BC Bioenergy Network and BC’s Innovative Clean Energy Fund for a biomethane project at the Salmon Arm landfill,[73] the Climate Change and Emissions Management Corporation of Alberta support for the Slave Lake Pulp (West Fraser) Bio-Methanation Project,[74] and funding from the Canadian Forest Service Investments in Forest Industry Transformation (IFIT) program for the Millar Western Bioenergy (biogas) project in Alberta.[75]

It is unlikely that ongoing taxpayer-funded programs to provide capital support, in order to overcome economic barriers, for RNG facilities employing commercial technology will prove attractive to provincial or federal governments. It is also not the approach that has been taken by European governments. In the absence of attractive markets and/or policy and regulatory regimes, industry growth may also cease should capital supports be removed (i.e., capital supports create only temporary industry growth).

4.2 Technology Development Support

While there are always opportunities to improve the performance of biogas- and landfill gas-based RNG production technologies through targeted technology development investments, the large number of commercial projects in Europe and the U.S. indicates technology is not a major hurdle to establishment of a vibrant RNG industry. A focus on technology development may in fact delay industry growth. The exception to this rule is RNG production from woody biomass, which performs poorly in anaerobic digestion facilities. The largest scale woody biomass-to-RNG plant is in Göteborg (Gothenburg), Sweden and is considered a demonstration facility. The G4 Insights PyroCatalytic Hydrogenation technology was tested by Gaz Métro and is considered to be pilot scale.[11] Therefore, there is opportunity for Canada's arms-length federal and provincial technology development support agencies, which include Sustainable Development Technology Canada, Emissions Reduction Alberta (formerly Climate Change and Emissions Management Corporation), Ontario Centres of Excellence, and BDC Capital amongst others, to make strategic investments in woody biomass-to-RNG technologies. Government department support programs, such as the IFIT program of CFS, may also advance commercialization of this technology opportunity. However, technology support in the absence of an accepting market or regulatory framework (or plan to create such conditions) may not prove worthwhile. This has been the case for Canadian support of cellulosic ethanol technology to date.

4.3 Non-Capital Policy Approaches to Sector Growth

As described in Sections 2 and 3, Canadian governments have not provided a legislative or regulatory framework that can support growth of an RNG industry in Canada. It has been natural gas distribution utilities that have taken the lead in trying to develop the industry with limited to no policy or regulatory support. The utilities' desire to see growth of the RNG industry is largely borne because of a Canadian policy emphasis on electricity when planning for climate change mitigation and low carbon energy. Examples of this focus on electrification for heating and transportation include the 2007 BC Energy Plan, the 2010 BC Clean Energy Act, the 2010 Ontario Long-Term Energy Plan, and the 2016 Ontario Climate Change Action Plan. As utilities with significant carbon-based fuel transmission and distribution infrastructure, it was important for utilities to showcase their ability to play a major role in meeting GHG reduction targets while recognizing the importance of previous infrastructure investments. However, the policy and regulatory environment has limited the ability of utilities to utilize RNG as a tool for GHG reduction.

The policy and regulatory changes required for growth of the RNG sector in Canada can be directly attributed to the pricing differential of natural gas and RNG, and the single homogeneous commodity fuel design of the natural gas regulatory structure. If RNG was cost competitive with natural gas, there would be no need for regulatory changes. However, if RNG production and consumption is to grow in Canada and bring about the desired GHG reductions, alternative policy and regulatory approaches from business-as-usual will be required. Several of the options are presented below.

Permit Utilities to Distribute the Cost of RNG across Their Customer Base

Provincial natural gas regulatory frameworks require utilities to obtain gas at commodity market prices and pass that cost onto customers without a markup. Utilities make their profit on the transport of the commodity. This arrangement is a result of the utilities receiving a monopoly on natural gas delivery. In some jurisdictions, gas marketers (resellers) are permitted to resell gas and enter into long-term supply agreements with customers. This arrangement creates competition in the retail gas market. However, the inability of utilities pass higher RNG acquisition costs on to customers or gas marketers means utilities would be losing money for any RNG purchased above the market price for natural gas. A change in the regulations of natural gas utilities by regulators such as the Ontario Energy Board or the BC Utilities Commission would be required in order to permit distribution of RNG acquisition costs (or at least network connection costs) across the customer base. This would bring regulation of natural gas utilities more in-line with that of electrical utilities, which can acquire higher cost electricity with positive environmental attributes (e.g., solar) and distribute costs across the electrical customer base.

This approach increases the cost of gas for all gas consumers served by a utility. However, as evidenced in British Columbia, voluntary RNG purchase programs will not result in significant industry growth. In order to limit cost increases to customers, the volume of RNG permitted as a percentage of the total gas volume could be limited. The UK has not needed to implement this approach because gas utilities, such as the National Grid, are not permitted to sell gas directly to customers. This is the role of Gas Shippers, which in turn sell the gas to Gas Sellers who interact directly with customers.

Permit Utilities to Enter Into Long-Term Supply Agreements

As with any large equipment investment, security of long-term sales is essential for securing competitively-priced financing. Some utilities, such as those in Ontario, are barred from entering into long-term offtake agreements with RNG producers. This is in direct contrast to biogas-electricity generators, which can secure 20-year power purchase agreements with the IESO (formerly the OPA). These agreements are essential to facility financing and the dichotomy of the two approaches creates an inequality in the energy sector that penalizes RNG producers. Biofuel producers in the transportation sector are also permitted to enter into long-term offtake agreements with fuel distributors, and again, these agreements are necessary for facility financing. Even if utilities are permitted to distribute the costs of RNG across their customer base, RNG producers will need long-term purchase agreements. These can be with utilities or alternatively with government-backed agencies/regulators under Renewable Heat Incentive/Feed-in-Tariff schemes (see *Implement a Renewable Heat Incentive* below). However, an agreement on a long-term connection, pipeline capacity, and transport of the RNG will be required in all cases.

Allow Utilities to Own Network Entry Facilities

In Ontario and some other jurisdictions, distribution utilities are prevented from owning any type of equipment involved in gas production. Their role is one of gas transportation and sales only. However, given the varying quality of biomethane, the need for it to meet strict specifications, and the responsibility of the utilities to ensure the specifications are met, it may be preferable for a utility to own and operate the network entry facilities connected to its grid. It is the preference of some of the Canadian natural gas utilities to also own the biogas upgrading (to RNG) facility, although evidence from other jurisdictions (e.g., UK, Germany) shows this is not required in order to develop the RNG industry.

A change in regulation would be required in some provinces for the natural gas distribution utilities to own network entry facilities and upgrading facilities.

Prioritize RNG in the Natural Gas Network

As with electricity producers, RNG producers rely upon a network/grid for customer access. Utilities are the gate keepers to that grid. Germany, the UK, and France have all legislated prioritization of biomethane in natural gas networks. They have also legislated for the utilities to provide network connections to biomethane producers, and in some cases such as Germany, mandated the utility to cover the majority of these costs (in the UK and France, the biomethane producer covers the cost but these are recovered via the RHI/FiT). Requirements on maximum connection time and minimum network availability (e.g., 96% in Germany) have created certainty for biomethane producers.

Implement a Renewable Heat Incentive

An RHI is the heat sector equivalent of an electricity Feed-in-Tariff or Standing Offer Program. Predetermined prices are offered for renewable heat generation in order to reduce GHG emissions associated with natural gas, heating oil, and propane use. It is logical for RNG to be included in a broader RHI, as a standalone RNG Feed-in-Tariff would likely disadvantage heat consumers not connected to the natural gas grid. With the biomethane component of a RHI, a single rate for biomethane injection on a net energy basis could be offered or alternatively, different rates could be offered for different processes (e.g., anaerobic digestion vs. landfill gas). The biomethane tariff could be on top of the commodity price for natural gas, as in the case in the UK, or could include the commodity price. The latter approach would likely require greater modification to natural gas market regulatory regimes than the former.

In order to prevent double-counting of RNG in incentive programs (e.g., payment for grid injection, payment for use in transportation), an RNG tracking system must be operated. This system would keep account of all contractual transfers of RNG and likely have a design similar to the UK Green Gas Certification Scheme.

Institute a Clean/Low Carbon Fuel Standard

The Canadian federal government has committed to adopting a national clean fuel standard in consultation with the provinces and territories. This clean fuel standard would likely require a decreasing carbon intensity for fuels over time and would ideally include RNG as one potential compliance fuel. Whether or not the clean fuel standard would be limited to transportation applications remains to be determined. Certainly use of the natural gas network for distribution of low carbon RNG would assist with meeting standard requirements in a cost-effective manner. A fuel supplier could purchase RNG directly from a producer and use the natural gas distribution network for transportation and delivery to customers. In this approach, the utility would not need to be involved in pricing of the RNG. However, several regulatory hurdles would still need to be addressed, including prioritization of RNG in the natural gas network and ownership of network entry facilities by utilities.

5 Conclusion

RNG is a highly-flexible commercial renewable fuel that can be blended with natural gas and utilized for space heating, electricity generation, industrial operations, and transportation. While the potential of RNG to reduce GHG emissions in a capital-efficient manner has been recognized by Canada's natural gas transmission and distribution utilities and some governments, necessary policy action to overcome hurdles to commercial deployment has be severely limited. Of prime importance is addressing provincial and federation natural gas utility regulations which prevent natural gas distributors from acquiring and supplying RNG at prices above those of natural gas. A variety of policy tools have been used by European governments to overcome similar RNG deployment regulatory and market hurdles. Learning from the experiences of these countries will enable Canada's provincial and federal governments to efficiently and effectively design policies to deliver on their RNG industry development objectives.

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Appendix 1. Summarized Comparison of RNG Regulations and Policies for Selected Jurisdictions

	Germany	United Kingdom	Canada	Ontario	British Columbia
General Market Status	Developed	Developed	Not Developed	Not Developed	Developing
Technical Grid Access	Legally required; RNG prioritized over natural gas; 96% minimum access required	Offer by utility to producer to connect legally required; moderate profit allowed for utility; terms of access, including availability, must be reasonable	No legal requirement; decision at the discretion of the utility	No legal requirement; decision at the discretion of the utility	No legal requirement; decision at the discretion of the utility
Biogas Upgrading Facility	Owned and operated by biogas producer	Owned and operated by biogas producer	Owned and operated by biogas producer	Utilities not permitted to own or operated facilities	Utility or biogas producer may own and/or operate
Network Entry Facility Ownership and Operation	Owned and operated by utility; biomethane producer must cover 25% of capital cost to a maximum of €250,000 when within 10 km of pipeline; utility must cover remainder and all operating costs	Utility or biomethane producer may own and/or operate, but key equipment in facility must be remotely monitored by utility if owned by biomethane producer; all costs the responsibility of the producer	Unknown, but likely owned and operated by utility	Unknown, but likely owned and operated by utility upon permission by OEB	Owned and operated by utility
Guaranteed Contracts for RNG Producers	Market largely dependent upon electricity Feed-in-Tariff; biomethane used for CHP, with heat utilization required	20-year biomethane injection contracts with government body via Renewable Heat Incentive; contracts at natural gas market prices with utilities	Long-term contracts permissible at the discretion of the utility and approval by the NEB	Utilities not permitted to enter into long-term contracts, unless exception approved by OEB	Utilities permitted into long-term contracts at their discretion and approval by BCUC
Distribution of Costs Across Customer Base	Cost of network entry facility installation and operation incurred by utility spread across all natural gas consumers in Germany	Commodity natural gas price distributed across customer base; RHI payment direct from national government (HR Treasury)	No ability to distribute costs across asset base; buyer of biomethane must assume costs	No additional costs beyond market natural gas price may be distributed across customer base	Utility-owned assets and minority of cost premium distributed across all customers; majority of RNG purchase premium borne by RNG consumers
Low Carbon/Renewable Fuel Standard	Biomethane eligible under renewable fuel standard; must comply with EU Renewable Energy Directive GHG rules	Biomethane eligible under renewable fuel standard; must comply with EU Renewable Energy Directive GHG rules	Renewable fuel standard not applicable to gaseous fuels; low carbon (clean) fuel standard in development	Renewable fuel standard not applicable to gaseous fuels; low carbon fuel standard being considered	Existing renewable fuel and low carbon fuel standards; biomethane is eligible under the LCFS

GREEN GAS GRIDS

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BIOMETHANE GUIDE FOR DECISION MAKERS

Policy guide on biogas injection into the natural gas grid

INTELLIGENT ENERGY EUROPE

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BIOMETHANE GUIDE FOR DECISION MAKERS

Policy guide on biogas injection into the natural gas grid

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www.greengasgrids.eu

GREEN GAS GRIDS

THE GREENGASGRIDS PROJECT PARTNERS

German Energy Agency - dena (Germany)

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Austrian Energy Agency (Austria)

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European Biogas Association

Consorzio Italiano Biogas (Italy)

Agentschap NL (The Netherlands)

Krajowa Agencja Poszanowania Energii – KAPE (Poland)

Slovenská Inovacná Eneregetická Agentúra - SIEA (Slovakia)

Natural Gas Vehicle Association - NGVA

CONTENT OF THE SECTIONS

The Biomethane Guide for Decision Makers includes six sections, each providing an insight to strengthen the process of policy decision for biomethane development.

Introduction

Section I **Biomethane as a high value renewable energy source**
This section helps in generating the basic understanding of biomethane and discusses the underlying importance of biomethane as a renewable natural gas substitute. The section also describes the available potential in terms of production of biomethane and the extent of climate benefits which are derived from biomethane utilisation.

Section II **Biomethane as an integrated energy solution**
This section is intended for decision makers to become aware of the linkage between the key EU (European Union) level policy drivers and biomethane production and utilisation. It also highlights the role biomethane can play by integrating within the existing natural gas infrastructure and fulfilling the renewable energy targets.

Section III **Best practice along the value chain**
This section describes the value chain of biomethane to natural gas grid injection. It covers:

- Biogas production and feedstock
- Gas upgrading technology and emission control
- Grid injection, biomethane trade and utilisation

Section IV **Support policies in Member States**
This section provides information on the regulatory framework as established in EU countries. It further describes the financial instruments which are being encouraged within EU countries for the promotion of biomethane.

Section V **Assess your biomethane strategy**
This section describes a framework to create a strategy for biomethane development within your country or region. The framework is a set of questionnaire which acts as a guide to identify weak issues within biomethane development strategy. Identification leads to aligning the policies to address the weak issues and promote the growth of biomethane industry.

Summary

INTRODUCTION

Biomethane – the green natural gas substitute

Biomethane is methane sourced from renewable biomass such as organic waste, sewage, agricultural residues or energy crops. It can also be derived from woody biomass like forestry residues through production of synthetic gas. In each case it offers a climate friendly way of substituting fossil natural gas and is a flexible energy carrier for fuel, electricity and heat applications, moreover, material use for biomethane offers additional possibilities. Spacial separating the biogas production plant from its point of utilisation offers a lot more potential for increase the energy efficiency by serving heat sinks with thermal energy from cogeneration in a biomethane combined heat and power plant (CHP).

Countries like Sweden, The Netherlands, Germany and Switzerland already gained experience in integrating this environmentally friendly technology into its energy system. Throughout Europe there are in total more than 200 biomethane plants in operation (Table 1), a fact that clearly shows: gas upgrading technology is mature and proven, thus technology is no longer to be regarded as a restricting factor.

Biomethane offers tremendous potential when it is produced and injected into the natural gas grid. The existing natural gas infrastructure can be used for transporting the green gas to its final consumer, where due to its flexibility, biomethane can make a contribution to reducing greenhouse gases (GHG) in all three sectors - electricity, heat and transport.

Table 1: Number of biomethane production plants, biomethane to grid plants, plants producing biogas from organic sources (incl. landfill, sewage, biowaste and agricultural sector) in several European countries (source: Fraunhofer UMSICHT 2013)

Country	Biomethane plants	Biomethane plants feeding the grid	**Biogas plants total** (incl. LFG, sewage, agricult.)	Agricultural	Biowaste (incl. organic MSW)	Sewage	LFG
Austria	10	7	**503**	approx. 300	55	134	14
Croatia	-	-	**12**	9	-	2	1
France	3	1	**269**	40	98	60	71
Germany	107	105	**9.200**	approx. 7.400	100	1.700	
Hungary	1	-	**58**	36	-	14	8
Italy	-	2	**810**	498	32	60	220
Netherlands	21	21	**235**	98	21	75	41
Poland	-	-	**219**	30	2	approx. 200	
Slovakia	-	-	**57**	34	4	10	9
UK	2	2	**360**	60		100	> 200
Sweden	47	8	**229**	14	23	135	57
Switzerland	17	15	**600**	140		460	
TOTAL	**208**	**161**	**12.552**	**8.659**	**335**	**2.950**	**621**

The GreenGasGrids Project promotes the European biomethane market

The Biomethane Guide for Decision Makers is part of the initiatives within the Intelligent Energy for Europe (IEE) funded project GreenGasGrids. The three years project is running until June 2014 and includes a consortium consisting of 13 European partners, involving key stakeholders from biomethane, natural gas and renewable energy industries, as well as EU level and national level policy makers.

GreenGasGrids aims to promote a significant contribution of biomethane to the Renewable Energy Directive (RED) targets of 20 % renewable energy and 10 % renewable energy in transport in 2020 as well as the renewable energy targets set by individual EU Member States.

Aim of the Biomethane Guide for Decision Makers

The Biomethane Guide for Decision Makers is intended as a source of quick reference for municipal, regional and even national level decision makers and authorities with influence over policies. This guide describes the benefits offered by biomethane and the ongoing policy schemes in EU countries supporting the development of biomethane.

This guide also provides a framework to analyse the current state of biomethane development within your region and a devise and strategy to identify the weak areas within development of biomethane industry. The framework is meant to encourage a deeper understanding in biomethane production and utilisation and initiate a proactive role in aligning the policies for further development.

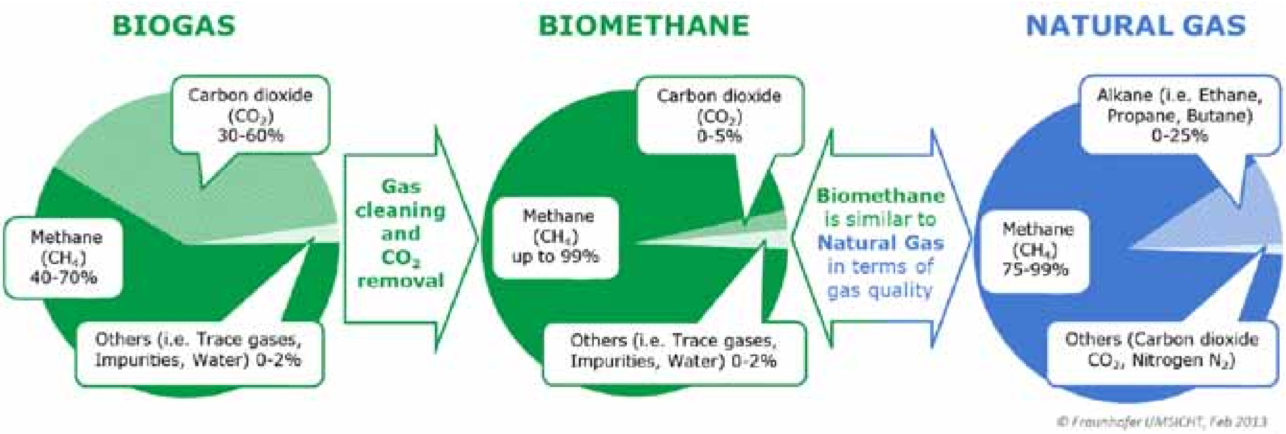
SECTION I BIOMETHANE AS A HIGH VALUE RENEWABLE ENERGY SOURCE

Biomethane is purified biogas

Biomethane is derived from biomass and has the major constituent in common with natural gas, which is methane. Intermixing with natural gas is possible in almost all proportions, thus biomethane is often referred to as a green natural gas substitute.

Biogas, the pre-stage of biomethane, can be sourced from almost all kinds of organic matter. Wet organic matter with low lignocellulose content, e.g. organic waste, sewage sludge, manure, is appropriate for biogas production by anaerobic digestion. Anaerobic digestion is a naturally occurring process where bacteria act upon moist organic material and decompose it into biogas as well as the nutrient rich digestate. The biogas thus produced, is cleaned of its impurities and upgraded to increase the methane content. The upgrading and purification is carried out to match natural gas specifications.

Figure 1: Chemical compounds and approx. share of biogas, biomethane and natural gas



The Biomethane Guide for Decision Makers focuses on the above described gas derived from anaerobic digestion. Additionally other renewable methane gases are embraced by the term biomethane, e.g. Synthetic Natural Gas (SNG) derived from woody biomass, or methane built by hydrogen from electrolysis and carbon dioxide by biological methanation process, also called Biogenic Synthetic Gas (BioSNG).

These technologies are on the way and offer potential on the mid and long term. However, since they lack of large scale applications they will not be focal point of this document. Nevertheless further information on alternative ways of producing biomethane is summarized in a separate report available at the GreenGasGrids project webpage www.greengasgrids.eu.

Biogas potential in 2020 is 41.6 Mtoe – to be combined with high flexibility when taking the biomethane option.

Biomethane is cleaned, upgraded and conditioned biogas. To evaluate the existing potential for biogas, substrate streams from agriculture, from waste water treatment and organic biowaste have been estimated by different studies (Table 2). AEBIOM assumes 25 million hectares agricultural land in EU-27 being available for bioenergy production, 5 million of which for energy cropping for biogas production. Including other substrates from the agricultural sector such as manure (assumed percentage of use of 35 %) and straw (assumed percentage of use 5 %), the agricultural sector raises a biogas potential of about 32.8 Mtoe. Additionally, the waste sector comprising sewage, municipal and industrial biodegradable organic wastes, generates substrate flows that with the appropriate treatment processes result in a biogas potential of 8.8 Mtoe. In sum, a total biogas potential of up to 41.6 Mtoe (1,741 PJ) primary energy is assumed to exist.

Tabel 2: Biogas potential of EU-27 (source: based on AEBIOM 2009, IE Leipzig 2007)

Origin (according to template of NREAP)	Potential (109 m³ methane)	Assumed percentage of use until 2020	Primary energy (109 m³ methane)	Primary energy (Mtoe)
Agriculture	58,9		35,4	32,8
Agricultural crops directely provided for energy generation	27,2	100%	27,2	25,3
Agricultural by products / processed residues	31,7		8,2	7,6
o straw	10,0	5%	0,5	0,5
o manure	20,5	35%	7,2	6,7
o rest (Landscape management)	1,2	40%	0,5	0,4
Waste	19,0		9,5	8,8
Biodegradable fraction of municipal solid waste including biowaste (biodegradable garden and park waste, food and kitchen waste from households, restaurants, caterers and retail premises, and comparable waste from food processing plants) and landfill gas	10,0	40%	4,0	3,7
Biodegradable fraction of industrial waste (including paper, cardboard, pallets)	3,0	50%	1,5	1,4
Sewage sludge	6,0	66%	4,0	3,7
TOTAL	**77,9**		**44,8**	**41,6**

Assumptions and parameters	
Heating value biomethane (kWh/m³)	10,8
conversion factor Mtoe/TWh	0,0860

10.9 Mtoe (456 PJ) primary energy were produced from biogas (i.e. agricultural, sewage, landfill gas) in 2010. Biogas energy is mainly recovered in the form of electricity. However, the efficiency degree of this energy utilisation is always linked to the degree of utilisation of heat from cogeneration and therefore with the availability of a suitable heat sink. Since the most biogas plants are located in rural areas and lack of useful heat utilisation, at the majority of the existing biogas plants there is scope for optimisation and for an increase in energy efficiency.

Biomethane production is able to decouple biogas production from use and offer much more flexibility to make efficient use of the existing potential. Thus, it is assumed that at least a third of the above described biogas potential is more efficiently used when converted to biomethane. On that basis the total biomethane potential sums up about 14 Mtoe annually (582 TWh).

Biomethane applications reduce carbon emissions

Biomethane is a renewable gas and replaces fossil energy carriers in the fields of transport, electricity production and space heating. Therefore, it is able to make a significant contribution to climate protection and CO_2 emission reduction.

The extent of the CO_2 savings resulting from biomethane applications depends on three important factors:
- Kind and source of **feedstock**,
- **Mode of operation** of the biomethane plant and
- **Utilisation pathway** of the produced biomethane.

Manure and organic waste are the most climate friendly feedstock

Biogas generation from manure and dung causes the most significant GHG reduction. Besides the production of renewable energy, the GHG mitigation effect results from capturing climate harming gases such as methane, nitrous oxide which are prevented to emit into the atmosphere. Therefore, the anaerobic treatment of these kinds of agricultural residues should enjoy maximum political support. Another substrate with a low carbon footprint is organic waste. Most commonly municipal biowaste is treated in composting plants. Provided using state of the art technology, biogas production from organic waste offers a more beneficial GHG balance than composting.
Biomethane from energy crops is the cleaner solution compared to fossil fuels. Even growing energy crops for biomethane production involves effort and energy. However, if digestate is used for manuring, nutrients will be kept in the biological cycle – which saves emissions from an energy-intensive mineral fertiliser production.

Mode of operation: Energy efficiency and methane slip influence the Life Cycle Assessment (LCA)

The careful and wary mode of operating a biomethane production plant is a key factor in an emission saving biomethane production. Especially when using energy crops for gas production special attention should be drawn on minimizing methane emissions. Methane is both, an energy carrier and a GHG. Thus, for safety, ecological and economical reasons best practice plants prevent methane from being lost to the atmosphere and have an eye on gas leakage and flue gas treatment. Best practice plant operation can be supported by requirements that act as prerequisites for financial support, but also educational trainings for the local authorities.

The appropriate biomethane utilisation with most CO_2 saving – a question of national conditions.

For evaluating the climate effectiveness of biomethane it is a key question which energy carrier is replaced by the use of biomethane. It is crucial to analyse the national situation and use biomethane where it has the greatest benefit.

All countries face different conditions regarding the emissions from their national average electricity, fuel and heat mix. Nations whose electricity production is substantially based on black and brown coal achieve a great effect when replacing electricity with renewables. Biomethane used in a CHP delivers not only electricity - it also provides renewable heat.

SUMMARY SECTION I WHAT TO KEEP IN MIND

- Biomethane is cleaned, upgraded and conditioned biogas. Its main component is methane, which makes it a potential substitute for natural gas.
- Biogas can be obtained from all organic matter, being wet organic matter the most commonly used, processed by anaerobic digestion.
- Biomethane production separates biogas production from consumption. Using the well developed natural gas infrastructure, the gas can be transferred to where it is needed.
- Biomethane is a flexible energy carrier and can be used as electricity, heat and vehicle fuel. As one of the few storable renewable energies it is able to provide energy on demand.
- Biomethane's contribution to emission mitigation is dependent of national conditions (national emission factor for electricity, heat and fuel) and the chosen utilisation pathway.
- Manure, energy crops, sewage and municipal organic waste offer a biogas potential of 41.6 Mtoe, a third of which (14 Mtoe) are assumed to be available for biomethane production – to increase efficiency and flexibility.

Figure 2: Harvesting and silage making from energy crops

SECTION II BIOMETHANE - THE INTEGRATED ENERGY SOLUTION

Biomethane satisfies all three principles – security of supply, sustainability and competitiveness.

The European energy policy for 2020 is built on three core objectives namely security of energy supply, sustainability and competitiveness. The principles are understood as follows:

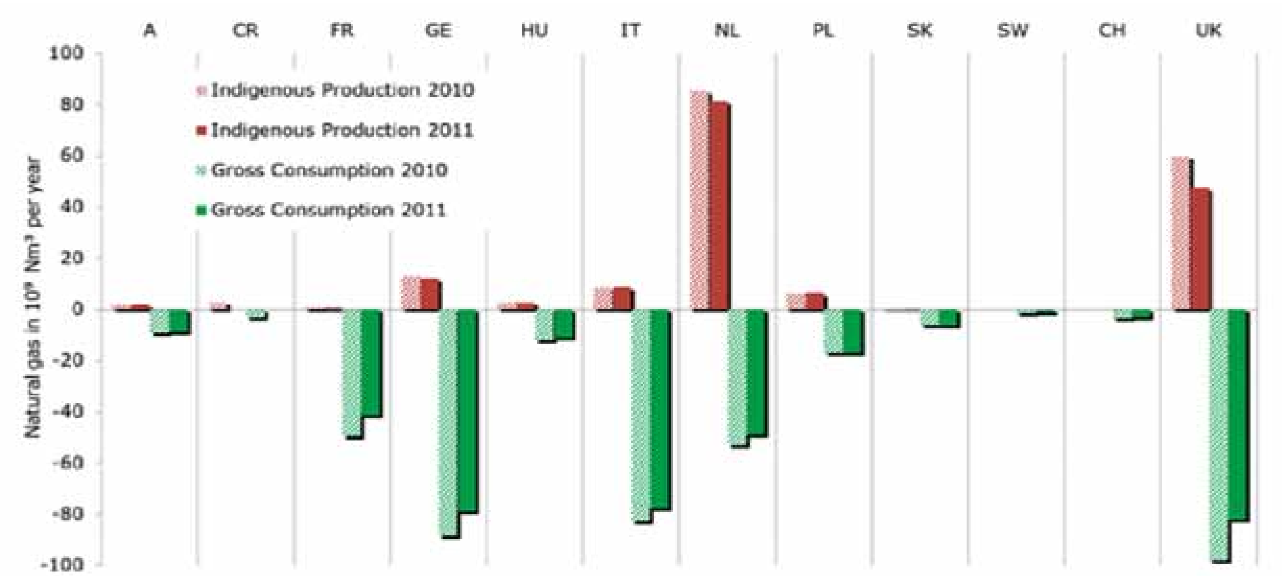
Security of energy supply - A strong need exists to minimize risk of exposure towards fossil fuel price volatility and ensure security of energy supply by diversifying the existing energy production sources.

Sustainability - The commitment towards sustainability calls for a reduction in greenhouse gas emissions, energy recovery from waste and increment in developing a healthier environment for future generations.

Competitiveness - Promotion of localized production of energy, and simulating technological innovation is the key to develop a competitive energy market and increased employment opportunities.

For a decision maker, it is crucial to understand how biomethane offers an integrated advantage and it is able to satisfy the referred policy goals.

Figure 3: Inland production and gross consumption of natural gas in different European countries (source: IEA 2012)



Principle 1: Security of energy supply

Fossil energy reserves are limited. To a high percentage fossil gas and oil are imported from non-European countries and already today in most European countries gas consumption exceeds inland production (Figure 3). In contrast, substrates for biomethane production are renewable and homemade or are sources from domestic processes. When injected in natural gas infrastructure, biomethane can displace fossil fuel usage proportionate to its production and therefore, enhances the security of energy supply. Key policy driver linking biomethane to security of energy supply are represented in Table 3.

Table 3: Key policy drivers linking biomethane to the principle of security of energy supply

EU policy directive	Target of the directive and link to biomethane
Renewable Energy Directive (2009/28/EC) on share of RES in overall final energy consumption	aims to achieve 20 % share of the overall final energy consumption from renewable resources by 2020. The binding target is translated individually for each member and stated in the National Renewable Energy Action Plans (NREAP). The NREAP provides a detailed road map of achieving individual countries renewable energy generation targets by setting out sectorial technology mix in their long term energy strategy.
➔ **Biomethane can be a valuable part in this mix and is able to contribute to raising the renewable share of the final energy consumption in different utilisation pathways.**	
Renewable Energy Directive (2009/28/EC) on share of RES in transport	calls for a 10 % share of energy from renewable resources in each member state's energy consumption in transport. By definition the directive includes contribution from biofuels and biogas, as well as hydrogen and electricity from renewable resources. There are no individual targets but vast proportion is expected to be met by biofuels. Transport biofuels derived from waste, residues, non-food cellulose material and lingo-cellulose are counted double for satisfying biofuel obligation to meet the target.
➔ **Biomethane is a clean vehicle fuel and can help achieve the renewable fuels target in most efficient way. The transport sector is fastest growing sector in terms of emissions and biomethane is a means to lower vehicular emissions achieving sustainable transport.**	
Renewable Energy Directive (2009/28/EC) on regulatory conditions to establish grid connection	Member states shall ensure non discriminatory charging of transmission and distribution tariffs against gas from renewable resource. Where relevant, member states have the responsibility of assessing gas network infrastructure to facilitate the integration of gases from renewable resources and area also required to publish technical rules regarding conditions for establishing network conditions and connection tariffs.
➔ **Renewable gases such as biomethane are to grant non discriminatory access to the gas grid**	

Principle 2: Sustainability

Biomethane is derived from anaerobic digestion of organic waste, industrial waste as well as purposefully grown energy crops. It is a renewable fuel and can effectively contribute within climate change strategies of reducing emission. Production of biomethane via anaerobic digestion is also a key part of an integrated waste treatment process. It is an effective means to counter waste disposal, achieve landfill objectives coupled with production of energy. Key policy drivers, such as the Fuel Quality Directive (2009/30/EC), the Landfill Directive (99/31/EC) and Sustainability Criterion of the Renewable Energy Directive (2009/28/EC), link biomethane to the principle of sustainability (Table 4).

Table 4: Key EU policy drivers linking biomethane to the principle of sustainability

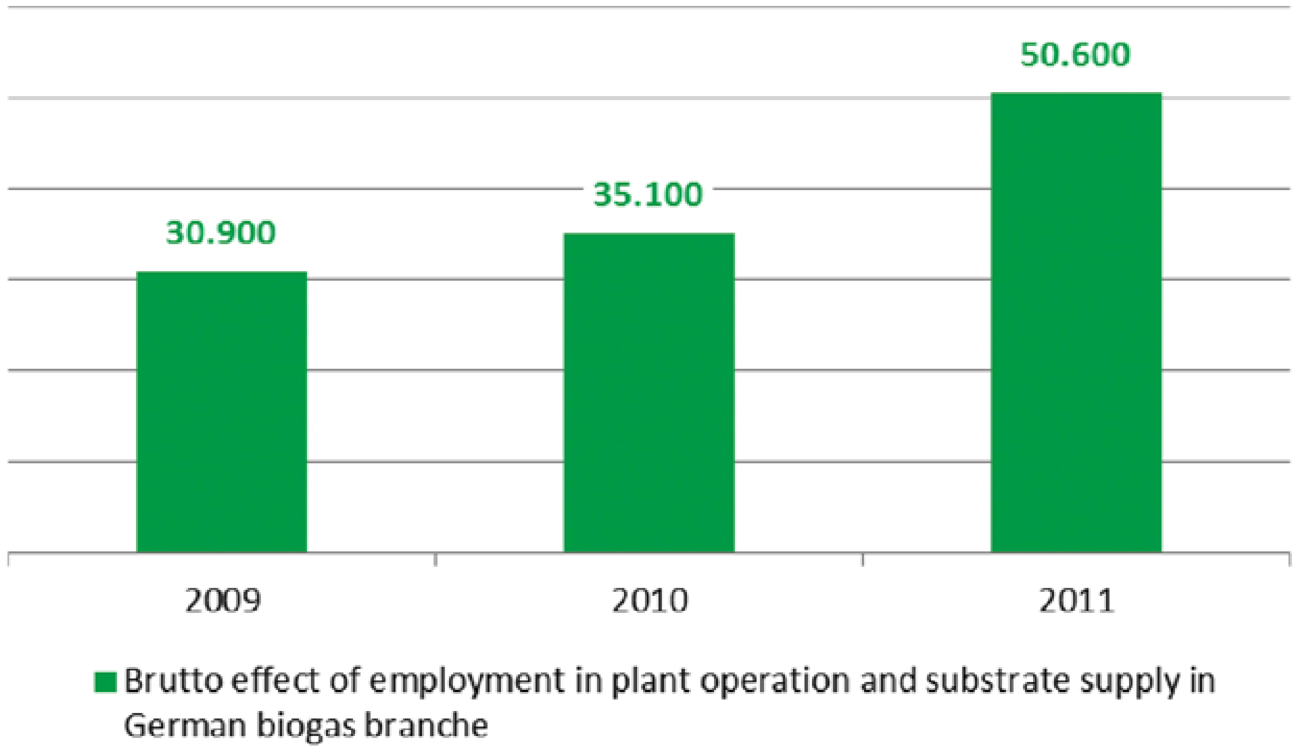
EU policy directive	Target of the directive and link to biomethane
Fuel Quality Directive (2009/30/EC)	aims to reduce the emissions from production and usage of fuels. The directive states from 1st of January 2011 onwards fuel suppliers must annually report a gradual reduction in GHG emission intensity by at least 6 % of average European GHG value of fossil based fuels for 2010.
➔ **Biogas produced from municipal organic waste, wet manure and dry manure; upgraded and blended with natural gas provides means to satisfy targets in Fuel Quality Directive.**	
Landfill Directive (99/31/EC)	mandates member states to ensure biodegradable municipal waste going to landfills to be reduced by 35 % of total amount produced in 1995, 15 years after it comes in force.
➔ **The avoidance of land filling of biodegradable component and satisfying the targets for the criteria makes a case for production of biomethane via anaerobic digestion.**	
Renewable Energy Directive (2009/28/EC) about the sustainability Criterion	sets criteria for biofuels and bio liquids for compliance to meet the obligatory targets. The GHG emission savings from the use of biofuels and bio liquids should be 35 % compared to fossil fuels and by January 2017 the target shall be increased to 50 % compliance value and further increment of 60 % is expected by January 2018.
➔ **Biomethane is able to fulfill the requested GHG emission reduction. Over the past recent years mechanisms have been developed to evaluate sustainability biomethane sourced from different feedstock.**	

Principle 3: Competiveness

Biomethane production generates high local added value. It is sourced from domestic biomass which is processed at local plants.
Despite its market price is higher compared to fossil natural gas, the increased local added value generated by biomethane production needs to be set off. Inland energy generation offers benefits such as

- Increased local added value,
- Support of the agricultural sector in the region,
- Generation of qualified jobs in planning, engineering, operating and maintaining of biogas and biomethane plants,
- Increased tax revenues in municipalities.

Figure 4: Effect of employment from biogas technology in Germany (source: Federal Environment Ministry Germany)



SUMMARY SECTION II WHAT TO KEEP IN MIND

- Biomethane integrates European Union energy policy goals:
  Sustainability of energy supply, security of energy supply and local competitiveness.
- High added value on local level.
- Biomethane can help achieve the renewable energy generation targets for production of heat and electricity. Biomethane usage in gas vehicles can balance the proportion of renewable fuels in transport.
- Anaerobic digestion and subsequent production of biomethane is an effective strategy to move towards targets of
  - Renewable Energy Directive (2009/28/EC)
  - Landfill Directive (1999/31/EC)
  - Fuel Quality Directive (2009/30/EC)

Figure 5: Biomethane production plant Könnern II, Germany

SECTION III BEST PRACTICE ALONG THE VALUE CHAIN

The dominant biogas production pathway is anaerobic digestion.

Anaerobic digestion is a complex biological process where organic material is converted into a gaseous mixture as well as residual digestate rich in nutrients. The organic substrate is pre-treated and cleaned and then undergoes decomposition in an oxygen free environment in digesters. The digestion takes place in a number of steps leading to the final production of methane, carbon dioxide and the residual digestate.

Organic waste and Manure are preferable substrates, purpose grown crops offer large potential

Biogas production through anaerobic digestion can utilise all kinds of organic material except lignocellulose (wood based) products.
A variety of feedstock is being used for biogas production. A broad categorisation can be made in terms of biomass from agriculture by-products and biomass from waste streams.

Table 5: Examples of biogas substrates

Agriculture based crops and by-products	• Farm manure and slurry • Agricultural by-products (i.e. sugar beet residue, spoiled corn, grass cut, cereals residue) • Purpose grown crops
Waste streams	• Sewage sludge and waste water treatment • Organic fraction of municipal solid waste • Residue from food industry (i.e. stillage, failed batches, vegetable trailings, potato peels, fruit pulp, brewer's grains, pomace, press cake) • Food waste and animal by-product from slaughterhouse

Farm manure and slurry occur as agricultural by product and are the traditional feedstock for biogas production. Using manure and slurry for biogas production mitigates GHG emissions and, moreover generates a suitable fertilizer, since after anaerobic treatment the nutrientscontained, e.g. nitrogen), are better accessible to plants after mineralisation. However, compared to other feedstocks such as biowaste or energy crops, these substrates contain comparably less energy due to a lower organic fraction. Thus, the required reactor volumes and consequently the specific investment costs per generated kilowatt hour for biogas from manure are higher than from energy rich substrates.

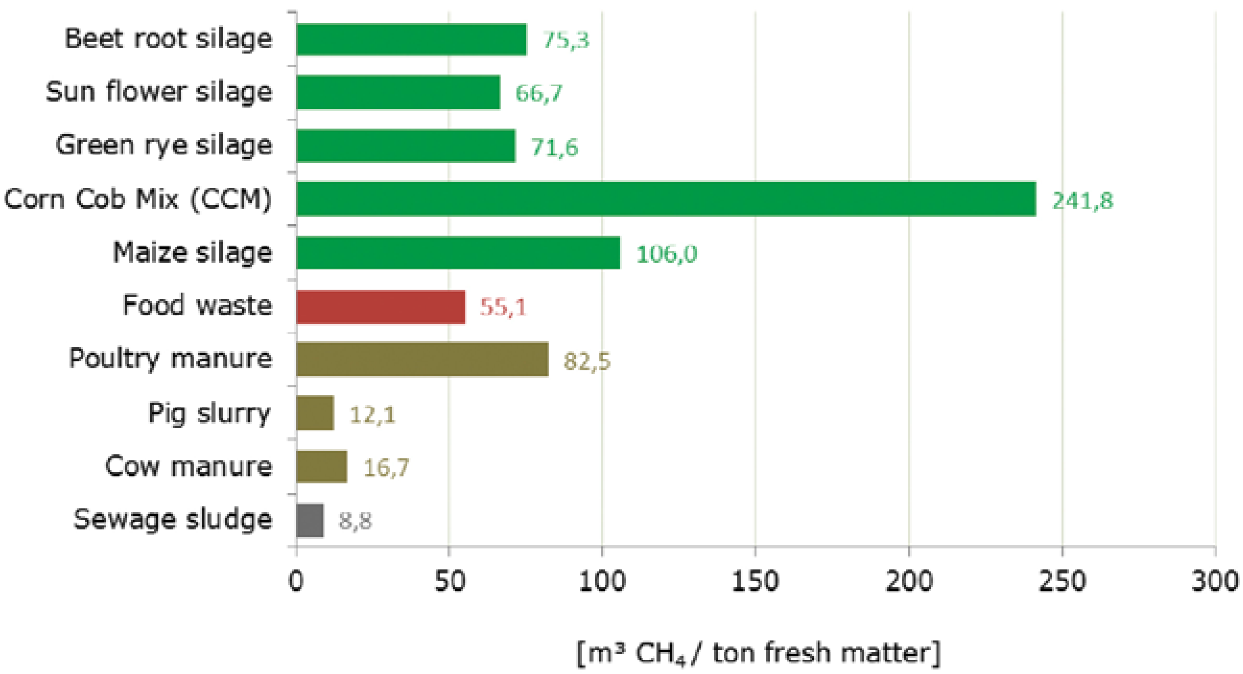
Purpose grown crops, also referred to as energy crops, can be specially cultivated for anaerobic digestion. Crops including maize, beet root, potatoes or grass silage are high yielding substrate that can be integrated in crop rotation practice as well. Blending energy crops with farm manure is a common practice to maximize yield and stabilize the process. The potential biogas yield from a single feedstock is shown in Figure 6. The choice of feedstock is based on gas yield data, annual availability as well as compliance to appropriate regulation. The range of gas yield available from the choice of feedstock is quite wide and multiple yields can be expected in cases of co-digestion.
When growing energy crops farmers benefit from an interesting additional segment and a second market for

their products. This market is able to compensate supply in years of rich harvest and creates demand for spoilt bulks. On the other hand, countries with high percentage of energy cropping experienced cases of competition for arable land which occurred primarily in regions with high livestock density. In order to avoid these conflicts, especially support measure for biogas production must pay attention to the specific regional conditions such as livestock density, dominant land use category and main crop.

Organic waste occur e.g. at food processing industry, as market wastes or from separated communal waste collection. An important step prior to the actual anaerobic treatment is substrate pre-treatment and removing contaminants such as plastics or packaging residues. Changing substrate load and the packaging remains require careful management and appropriate plant technology. Therefore, this process differs in plant design compared to digestion plant using agricultural substrates or sewage sludge.

Sewage sludge refers to the residual, high water containing remains from waste water treatment processes. Anaerobic digestion is an efficient technology for sludge treatment. Digestion decreases the sludge volume as well as volatility. The remaining digestate can be checked for toxicity and sent to landfill or used as landscaping purpose. Due to high water content the gas yield related to fresh matter seems to be low compared with gas yields derived from energy crops (Figure 6). Considering that waste water treatment capacities are expected to extended, sewage sludge bears considerable potential for biogas and biomethane production.

Figure 6: Methane yields from different biogas substrates related to fresh matter (sources: KTBL, Archea GmbH)



Gas upgrading and emission control

Raw biogas obtained from anaerobic digester, sewage treatment facilities or landfills are not suitable to be fed into the gas grid with its formative composition, since it is contaminated with impurities that may cause damage to downstream distribution and utilisation equipment. Hence raw biogas needs to be cleaned of its impurities and upgraded to match the combustion specifications of natural gas in the grid. The necessary process steps are in general removal of impurities, gas drying, removal of carbon dioxide while the order of the steps is linked to the applied CO_2 removal technology. Before gas injection it might be required to adjust the heating value. The chapter on grid injection will address these process steps more in detail.

Gas pretreatment: The treatment of biogas starts with a cleaning process that removes trace components harmful to the natural gas grid, appliances or end-users. Based on the substrate and technical design of the reactor, raw biogas may contain impurities that have a detrimental effect on end equipment. Table 6 provides an overview on the most important substances.

Raw biogas composition varies depending on the feedstock and digestion process. Each country has its own set of quality regulations for feed-in of gases in the public supply. When injecting the raw biogas in gas grid, cleaning and upgrading of raw biogas is performed to match the local specifications of natural gas. The technical standards are usually defined for unconventional gases including biomethane produced via gasification or via anaerobic digestion.

Table 6: Contains and contaminants of biogas, its sources and impacts on plant technology

Impurity	Source	Impact
CO2	Mineralisation of carbon from organic biomass (main component of biogas)	Reduces overall calorific value; promotes corrosion of metallic parts by formation of weak carbonic acid.
H2S	Proteins, manure, organic waste	Acts as corrosive in pipelines; causes SO2 emissions after combustion or H2S emissions in case of incomplete combustions; poisons the catalytic convertor.
H2O		A major contributor to corrosion in aggregates and pipelines by forming acid with other compounds; formation of condensation leading to the damage of instruments; freezing of accumulated water in high-pressure low temperature conditions.
NH3	Proteins	Leads to an increase in antiknock properties of engines; causes formation of NOx.
N2	Air input e.g. by desulphurization with air	Leads to an increase in antiknock properties of engines; leads to a reduction in calorific value as well.
Siloxanes	Cosmetics, antifoaming agents, washing agent, hydraulic fluent	They are mainly present in biogas formed out of landfill or sewage gas. These hydrocarbon acts as quartz of silica, grinding motor parts.
Terpene	Essential oils (e.g. from plants, fruits, cosmetics)	
Ester	Fruits, fruit aroma	
Dust		Damages vents and exhaust by clogging

CO_2 removal: The main process step in the biomethane production process is the removal of carbon dioxide. Currently there are several technologies in practice that are used to clean and upgrade biogas to reach the required specification for natural gas grid injection. A brief description of these techniques is given in Table 7.

Table 7: Processing principals for CO_2 removal from biogas

Basic Principal	Process technology	Process description
Absorption	High pressure water scrubbing	Water absorbs CO_2 under high pressure conditions. Regenerated on depressurizing
	Chemical scrubbing	Amine solution absorbs CO_2 regenerated on heating.
	Organic solvent scrubbing	Polyethylene Glycol absorbs CO_2 regenerated on heating or depressurizing.
Adsorption	Pressure swing adsorption (PSA)	Pressurized gas is led through an adsorber bed where the molecules adsorb with different strength at the adsorber. The separation effect is caused by the different strength of junction depending on the kind of gas.
Membrane	Membrane separation	Pressurized gas is passed through a membrane system, which has selective permeability for CO_2 respectively methane.
Cryogenic	Cryogenic separation	Biogas is cooled till CO_2 separates out as liquid form.

The energy demand for CO_2 removal differs and is dependent on process conditions such as

- Process conditions such as ambient temperature,
- Condition of the raw biogas e.g. methane content, contaminants,
- Requirements for product gas (biomethane) methane content in the biogas.

However, all technologies bear their own strengths and weaknesses. A well engineered site specific solution takes advantage of the strengths and engineers an energy efficient plant.

- **Example 1:** A heat requiring process e.g. an amine scrubber is suitable for a plant site where a cheap heat source is available, e.g. cogenerated heat from a CHP. If such a heat source heat is not available and has to be generated e.g. by burning wood pellets, costs are added and the overall efficiency of the technological process is slightly lowered.

- **Example 2:** Some biogas upgrading technologies operate at over pressure and produce compressed biomethane, e.g. membrane technology operating at up to 16 bars provides biomethane at almost the same pressure level. Feeding this compressed gas into a gas grid with similar pressure level, compression energy can be saved. If the gas is fed into a grid section at a much lower pressure level, the technology's advantage will remain unused.

Well implemented political measuressupport efficient plant engineering and provide incentives for all involved actors, most commonly biomethane plant operator and gas grid operator.

Emission control is necessary for safety, economic and first of all for ecologic reasons.

Methane emissions are often a result of failures in construction works or of poor plant operation. Gas losses may cause

- **Deterioration of the GHG balance**, since methane has a global warming potential of 25 compared to CO_2,
- **Odour problems** and resulting conflicts with residents,
- **Decline in revenues** from gas sale,
- **Safety** problems (danger of explosion and poisoning)

and therefore are to be prevented by appropriate measures. Regular checks with sniffer or with special gas cameras conducted by trained staff as well as appropriate plant engineering and well chosen operating parameters must become a matter of course.

Besides leakages at gas pipes or gas storage tanks, the lean gas stream of the CO_2 removal plant may be a source for methane emissions. Only amine scrubbing plants reach concentrations lower than 0.1 %. Here a post treatment of the lean gas can be waived. Other upgrading technologies operate with residual methane contents in the lean gas stream in the range of 0.6 % to up to 8 % related to raw gas concentration, depending on type of technology, plant set up and mode of operation. For these cases lean gas treatment is advised. Proven technologies for air purification are already used in other applications. For lean gas treatment at biogas upgrading plants good experiences were made with using for example:

- Thermal air combustion,
- Catalytic air combustion,
- Flameless oxidation (FLOX).

The German regulation limits methane emissions from upgrading plant's lean gas down to 0.2% related to raw gas. The financial support is linked to this minimum limit. Germany's biogas production relies strongly on purpose grown crops.

Grid injection, trade, utilisation

The biomethane plant is connected to the natural gas grid by a gas pipeline of several meters to kilometers depending on the distance between the biomethane plant and the choosen grid connection point. A facility of major importance is the grid connection station which completes several tasks:

- Measuring gas quality and flow are measured by calibrates instruments,
- Adjusting the heating value e.g. by adding propane, butane or air,
- Compressing biomethane to the required pressure level.

To ensure a safe and smooth operation of gas grid and connected gas utilisation equipment, biomethane has to meet **gas quality standards**. The requirements differ between the countries and even between single grid sections within one country. Apart from methane number, wobbe index and heating value also the minimum limits for various trace gases vary. Reasons are different natural gas qualities and their origin; however, also particular characteristics of some national grid like type of material used are given reasons. Several gas standards offer the possibility to feed biomethane off spec gas, meaning gas that does not fully comply with the limits, as long as the resulting gas quality is in line with the requirements. This praxis offers an economic option when feeding high calorific gas grids at high volume flow.

In 2011, the European Committee decided to give a mandate to a new CEN technical group (CEN TC 408) to develop a **common standard for biomethane** which is currently under development. The scope of CEN TC 408 encompasses both biomethane and natural gas as fuels and biomethane for injection into natural gas grids.

Biomethane injection is possible at any pressure level of the natural gas grid.

The natural gas grid contains different sections that are operated at different pressure levels and suit different purpose. The grid parts can be divided into

- Interregional transportation grid (usually > 16 bar),
- Regional transportation grid (about 4-16 bar),
- Distribution network (usually < 4 bar),

while the pressure ranges differ between the various countries. Naturally both options, injecting in the high pressure grid as well injection in the low pressure grid, bear pros and cons. At lower pressure levels, injection requires less effort for gas compressing and therefore less energy and costs are to be spent. On the other hand, these grids may be limited in its take-up capacity. In times of low gas consumption in the connected supply area this might become an issue. Grids at higher pressure levels transfer most commonly high gas volumes and therefore are less limited in gas take up capacity.
This advantage has to be paid. Energy demand for compression increases with required pressure level and is linked with costs.

Both investment and operation costs for grid connection need to be considered when developing financial support mechanisms for biomethane injection. Grid operator and biomethane producer should look for the most suitable and most efficient grid connection point in terms of

- Distance between biomethane plant and grid connection point (length of connection pipe),
- Injected pressure level,
- Design and equipment of the gas connection station.

Transparency for all administration steps is an important issue. Documents for planning grid connection such as

- Maps of transportation and distribution gas grid
- Draft agreement for grid access
- Requirements for gas quality

should be easily accessible for all involved stakeholders.

Biomethane trade takes primarily place within a nation's border. Cross-border trade is able to balance the markets and increase flexibility.

Biomethane transport makes use of the natural gas infrastructure and thus underlies partly the rules of national gas trade. This requires calibrated metering, energy balancing.

Biomethane is a green gas and distinguishes from natural gas by an important feature: it is renewable and has the green feature. To keep track of this valuable characteristic after having been mixed with fossil natural gas, a tracking mechanism is needed. Mass or energy balances serve reliable and complete retracing of biomethane from its production site to the final consumer. They can serve various purposes

- Providing proof of the green feature,
- Keeping track of the parameters related to the gas production that relevant for financial support (kind of substrates used, plant size, certificate for complying with emission limits, energy efficiency of the plant etc.),
- Avoiding doubled sale.

Therefore, several countries already established its national tracking system, the biogas register (Table 8).

Table 8: Tracking mechanisms for biomethane in different countries

Country	Name of mechanism	Institution in charge	Status
Austria	Biomethane Register Austria	AGCS	In operation since May 2012
Denmark		Energinet	In operation
France	GoO register	Gaz réseau distribution France (GrDF)	Under development
Germany	German Biogas Register	German Energy Agency (dena)	In operation since 2011
The Netherlands		Vertogas	In operation since July 2009
Poland	Register of energy companies producing agricultural biogas	Agricultural Market Agency	
Sweden		Energigas Sverige	In operation
Switzerland		Federation of Swiss Gas Industry	
UK	Green Gas Certificate Scheme	Renewable Energy Association REA	In operation

Biomethane trade predominantly takes place in the country of its production. There are only a few examples of physical cross border biomethane trade, e.g. from Germany to Sweden, and to The Netherlands as well as from the UK to The Netherlands. If the market is not balanced, meaning demand exceeds supply or vice versa, cross border trade is able to increase flexibility and transfer biomethane where it is needed. Barriers are often created by the different national regulatory frameworks, but they can be removed by harmonising the national tracking systems which means that two different biogas registers are able to exchange biomethane amounts from the country of production to the country of final consumption.

German Biogas Register and Dutch Register of Vertogas harmonised their systems in order to be able to exchange biomethane amounts between the two countries.

European Committee's aim to strengthen the EU internal energy market is an objective that goes in line with the principle of competitiveness. Establishing a European biomethane market brings Europe a further step into the right direction.

Various choices for biomethane applications – for electricity or heat generation on demand or for vehicle fuel or material use

Electricity generation: Biomethane is used for electricity production in gas engines, such as biogas. Electricity is fed into the public electricity grid while the cogenerated thermal energy is used for heating or drying applications. The energy efficiency of the overall process increases with the degree of heat utilisation. Separating the biogas production site from the final place of consumption via biomethane production, much more heat sinks become available. In order to justify the energetic effort for biogas upgrading process and grid injection, biomethane must be used in cogeneration in CHP and minimum limits for heat utilisation should be defined.

In energy systems with a major share from fluctuating energy sources such as wind and solar, storable energy carriers are becoming more and more important. Biomethane is storable and uses the public gas grid as energy storage. This allows the biomethane CHP operator to generate green electricity on demand.

Heat generation: In the same way as natural gas, biomethane can be used for household applications such as cooking and heating. Compared with other renewable heat sources biomethane is one of the more costly fuels, however, it offers to operate an existing natural gas heating system with green energy. If a country is weighing to give priority to this biomethane utilisation pathway, contribution of other renewable heat sources need to be taken into consideration and support mechanisms need to be arranged accordingly.

Vehicle fuel: Biomethane can fuel CNG and LNG vehicles and thus is able to green both public and private transport. CNG and biomethane complement one another in the transportation sector. Both share the CNG infrastructure of fuel stops and gas grids and serve CNG cars. Moreover, biomethane is able to green CNG traffic while fossil CNG provides quantity.

The stage of development regarding CNG fuelled mobility in European countries varies. Number of CNG service stations and CNG vehicles registered are indicating to which extent gas fuelled mobility has already taken market share. If biomethane is planned to play a major role in the transport sector, the development status of CNG infrastructure becomes a significant issue. To successfully introduce biomethane as a vehicle fuel, an established CNG infrastructure must exist or, in case of long term planning, must be supported and promoted in parallel.

Check out for more information on natural gas mobility the Webpage of NGVA at www.ngvaeurope.eu

Material use: Natural gas is used as a reactive carbon source in chemical processes e.g. for fertilizer production (Haber Bosch process) and iron-ore reduction processes. Furthermore, natural gas is expected to gain increasing importance as resource for the chemical industry, especially for the production of short chain olefins. However, in view of the fact that fossil resources are on decline, the chemical industry is aware that its raw material base needs to be widen. Apart from the expiring fossil oil and gas, the industry starts now looking at biomass as renewable resource. Biomethane can replace fossil natural gas as a resource for the production of base chemicals via intermediates like synthesis gas or methanol.

SUMMARY SECTION III WHAT TO KEEP IN MIND

- Waste and manure are preferable substrates, while purpose grown crops offer large potential. Financial support for biogas from energy crops has to be developed in accordance with regional and agricultural conditions in order to avoid conflicts and undesirable developments.

- Biogas upgrading means gas pre-treatment (gas drying, removal of contaminants) and CO_2 removal. For all steps proven technology is available.

- Site specific engineering is essential to ensure the most efficient technical solution - and to maintain the public acceptance for this technology. Policy support should address all involved stakeholders and set incentives for building an energy efficient plant.

- Biomethane offers various utilisation pathways such as
  - Vehicle fuel
  - Electricity generation
  - Heat generation
  - Material use

- In energy systems with high percentage of fluctuating energy carriers (wind, solar) storable and flexible energy carriers are required to ensure stable grid operation. Biomethane CHP can deliver green electricity generation on demand.

Figure 7: Biomethane piping and measurement equipment in the grid connection station

SECTION IV SUPPORT POLICIES AND MEASURES

Various support measures are applied in biomethane forerunner countries.

Biomethane capacity development is not only a result of the political will targeting the inclusion of biomethane as a renewable fuel with prime importance in energy mix. The capacity is equally affected with reliable and long lasting financial support mechanisms and investment subsidies since under the current market conditions biomethane can not compete against natural gas in sales price.

There exists sufficient variation in support policies within nations driving biomethane demand. These support schemes mainly fall under measures such as feed-in tariffs (FIT), investment aids, quota systems or beneficial tax policies (Table 9). The success of all measures depends in the goodness of fit between sharing of project risks and revenues to ensure a balanced promotion of biomethane. Furthermore, programs for closely related fields such as promotion of natural gas applications in CHP or fuel applications must be coordinated with biomethane supporting measures to avoid competitive situations. Obviously in a quota system for renewable electricity it is unlikely that biomethane will prevail over other green electricity sources like wind and solar, if biomethane's particular talents, namely flexibility and its storage properties, do not pay.

Biomethane projects need long realisation times – and therefore need stable support conditions and long term policies

RES projects with long project development and implementation times face a risk in changing legal framework and in decreasing revenue streams. Especially for these kinds of projects a reliable and long term policy is important. Biomethane projects need several months, and in some cases up to few years, until the plants start its operating mode. The German example shows that even in countries with an established legal framework for biomethane the time period between planning stage and plant commissioning on average is around 32 months – while the procedure to negotiate and realise the grid connection takes the longest time period.

Table 9: Overview on different support measures for biomethane

Support measures at the production side
Direct investment support, e.g. in form of • Grants for plant construction, • Interest reduced loan.
Cost sharing for grid connection
Standardisation of licensing procedures for plant construction
Non discriminatory / priority access for renewable gas to the public grid
Transparency in terms of technical requirements for gas feed-in
... at the consumption side
Feed in tariffs, e.g. for • Renewable gas, • Renewable electricity from CHP.
Obligatory quota e.g. for the consumption of • Renewable fuel, • Renewable heat, • Renewable electricity.
Investment support, e.g. for • CHP-systems, • CNG cars, • Bus and vehicle fleets.
Beneficial tax policy featuring tax releave, exemption or refund, e.g. in terms of • Energy tax, • Fuel tax, • Electricity tax, • Income tax.
Revenues from emission trade

Apart from financial support additional measures addressing financing, licensing and legal aspects are essential for reducing project risks.

During planning stage the licensing procedure bears the risk to project delay. Clear licensing procedures are the key for a realisation according to time schedule. Guidelines for local authorities may help facilitating the permitting process and reduce the project risk at that stage.
The grid connection often turns out to be the bottle neck of a biomethane project. Therefore, rulings on network connection process need to name clear rights and responsibilities for all involved partners. A supervising authority (e. g. a governmental energy agency) can help to ensure a fair and effective negotiation and implementation of the grid connection.

The first step into this new technology is setting up a demonstration plant. Biomethane plants in pilot scale scientificly accompanied by appropriate R&D programs help to gain experiences, to identify technical and administrative barriers and to set a proper basis for industrial stage projects. Demonstration plants face a lot of barriers being a first of a kind in the country like unproven legal framework, inexperienced local authorities and gas grid operators, poor established service network for upgrading technology provider. Further information on Best practice approach to implementing a biomethane demonstration project is summarized in a separate report available at the GreenGasGrids project webpage www.greengasgrids.eu.

Examples from the GreenGasGrids member countries

Several countries already established support mechanisms for biomethane. Having a closer look at the strategies of these countries it becomes obvious that the applied mechanisms differ and come into action at various points of the biomethane value chain. In the following, an overview is given on the major support mechanisms of three biomethane forerunner countries i. e. Sweden, Germany, The Netherlands. The United Kingdom presents a country that just started its biomethane carreer and is included as an additional example. The measures of each country are shown along the biomethane value chain, starting from substrates and bioggas production up to grid injection and final utilisation in fuel, electricity, heat sector respectively for material use.

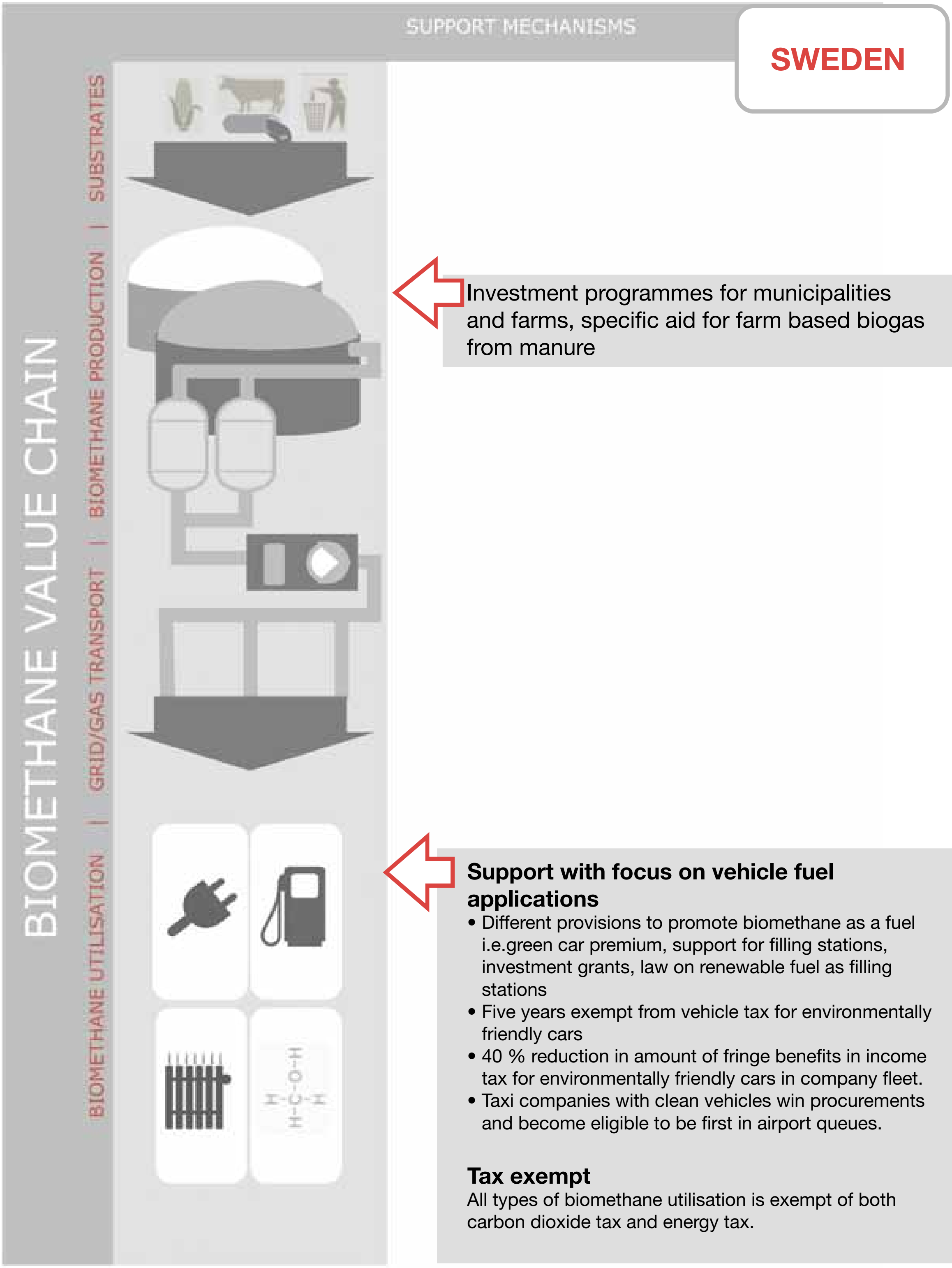
The Swedish example shows a promotion system that supported target orientated biomethane production via investment programs for municipalities and farmers and in parallel, created a demand for biomethane by promoting green transportation (Figure 7).

Just like Sweden also the UK goes for a two stage scheme and provides investment support on the one hand to directly support plant construction, and on the other hand established with the Renewable heat incentive (RHI) the instrument that is mainly driving the UK biomethane market. Besides the RHI biomethane receives support from other measures affecting the utilisation side of the value chain (Figure 8).

Germany sets their focal point at the end of the value chain and integrated biomethane support into the existing biogas feed in tariffs for electricity and the biofuel quota. Since grid connection has been identified to be a critical issue, the German ordinance on gas grid connection strengthens the position of the biomethane producer with several measures and provides priority access and transport for biomethane (Figure 9).

The Dutch support scheme approaches both biomethane production using its main support scheme called SDE+, and offers support for biomethane utilisation in the transport sector. The SDE+ scheme provides a feed-in subsidy covering the difference between production costs and energy price. (Figure 10). It operates on a first come first served basis within each categories eligibility criteria's whereby projects applying for support in low cost category will be served first. In 2012 for biomethane there are five categories ranging from 0.483 €/Nm^3 to 1.035 €/Nm^3.

Figure 8: The Swedish support measures shown along the biomethane value chain



Investment programmes for municipalities and farms, specific aid for farm based biogas from manure

Support with focus on vehicle fuel applications

- Different provisions to promote biomethane as a fuel i.e.green car premium, support for filling stations, investment grants, law on renewable fuel as filling stations
- Five years exempt from vehicle tax for environmentally friendly cars
- 40 % reduction in amount of fringe benefits in income tax for environmentally friendly cars in company fleet.
- Taxi companies with clean vehicles win procurements and become eligible to be first in airport queues.

Tax exempt

All types of biomethane utilisation is exempt of both carbon dioxide tax and energy tax.

Figure 9: The German support measures shown along the biomethane value chain

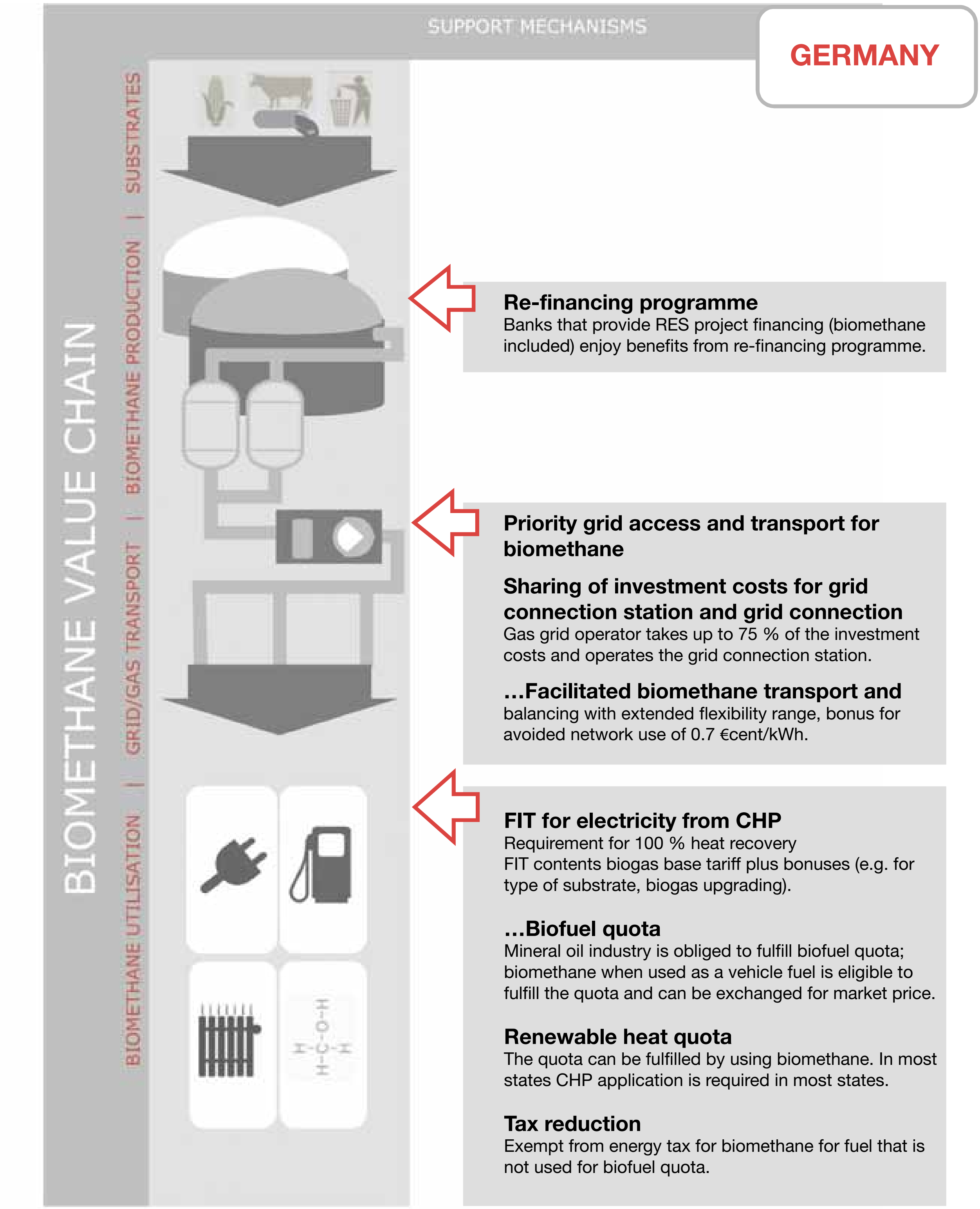


Figure 10: The Dutch support measures shown along the biomethane value chain

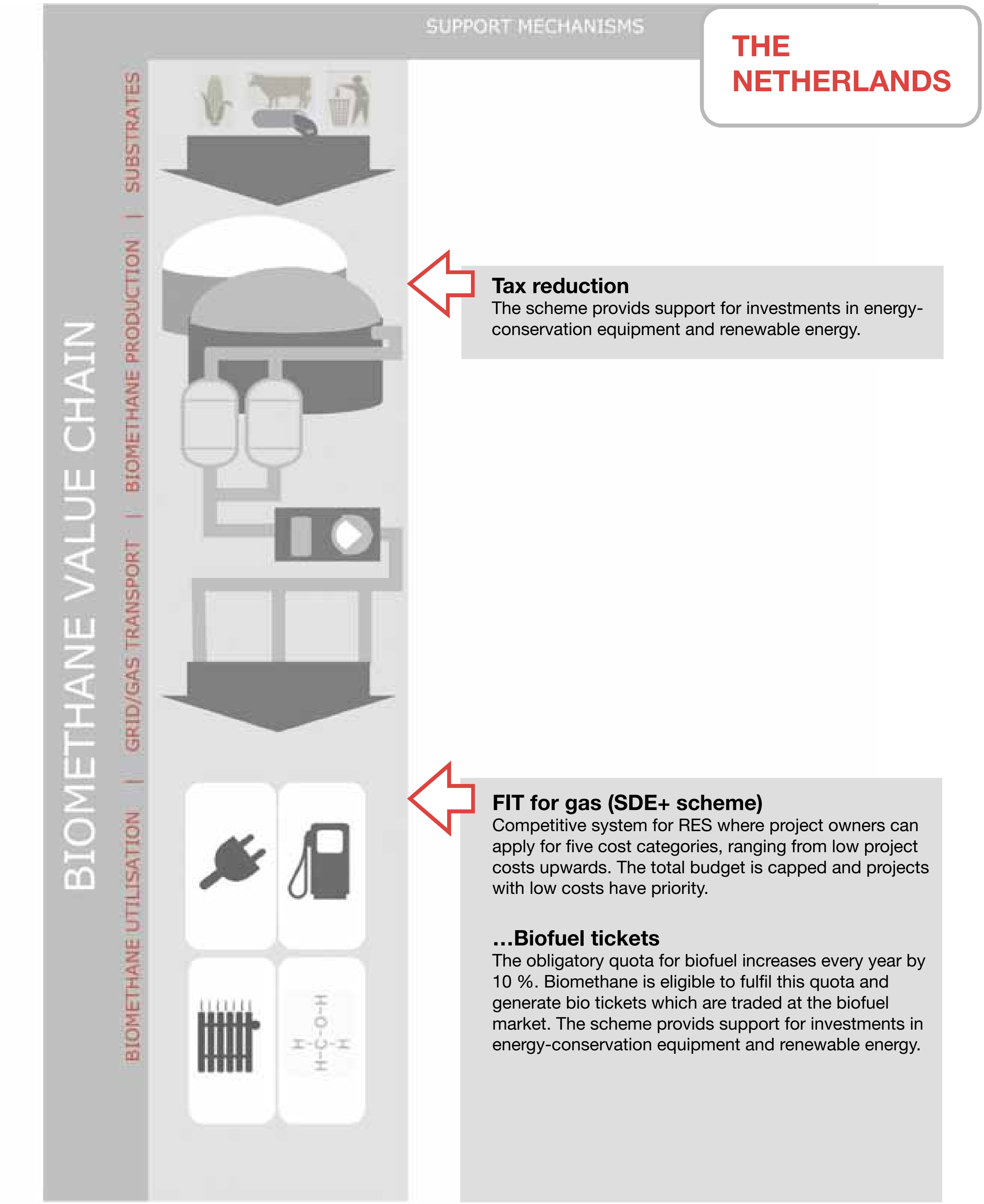
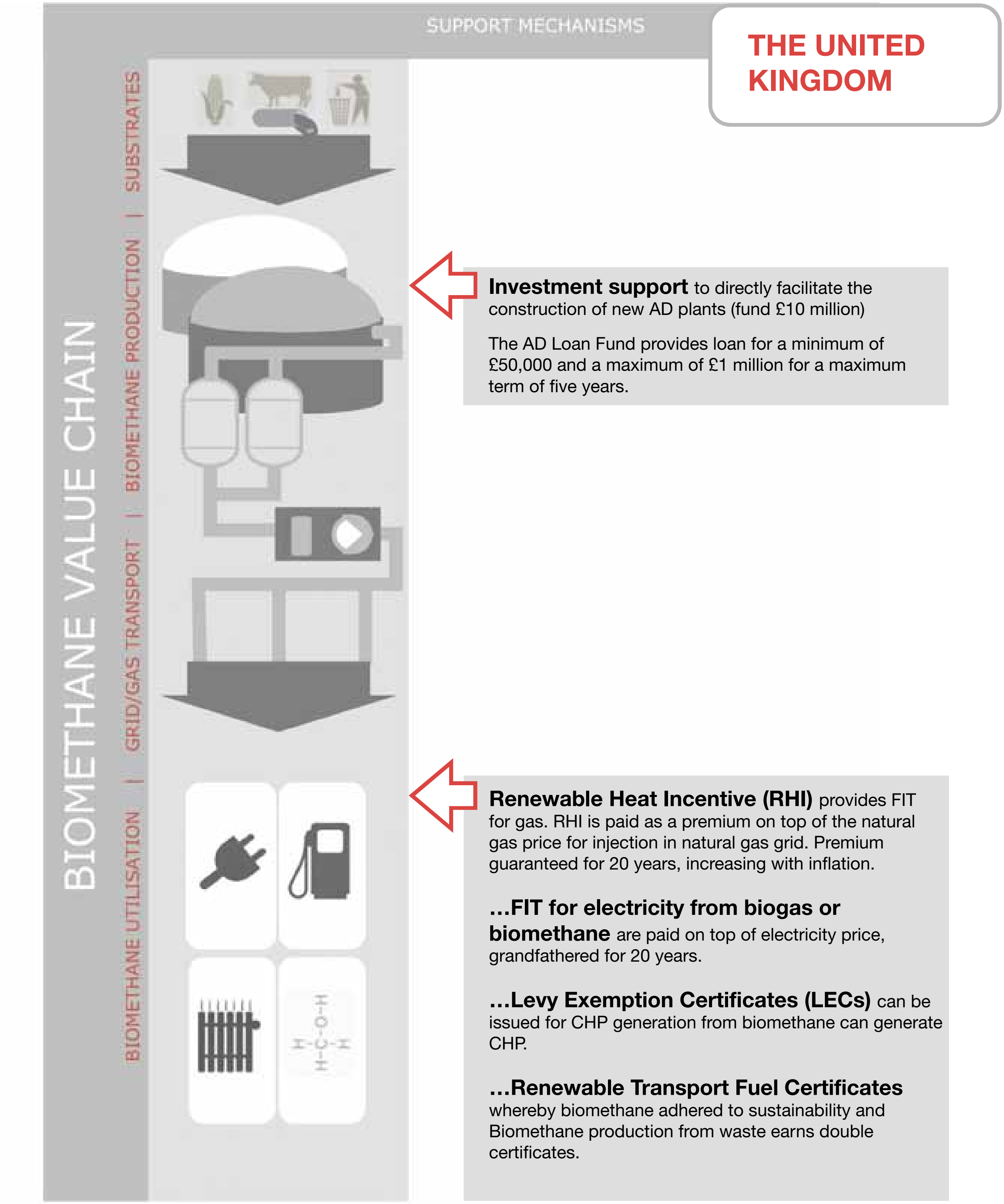


Figure 11: The UK support measures shown along the biomethane value chain



SUMMARY SECTION IV WHAT TO KEEP IN MIND

- Biomethane relies on support schemes since under the current market conditions biomethane can not compete against natural gas in sales price.

- Biomethane forerunner countries use divers support schemes for biomethane, most prominent
  - Feed-in tariffs for gas or electricity
  - Biofuel quota or certificate systems
  - Beneficial tax policy
  - Investment aid for biomethane production plant

- A pure quota system for green electricity does not pay biomethane's distinguished features and the resulting advantages for the energy system.

- Biomethane projects have long development periods and therefore are reliant on long-term policies offering stable conditions and grandfathering.

- Apart from financial support additional measures addressing financing, licensing and legal aspects are essential for reducing project risks.

SECTION V IDEAS TO ASSESS YOUR NATIONAL BIOMETHANE STRATEGY

In this section a framework is described that shall help decision makers to assess their national biomethane market. The framework is a set of questionnaire which acts as a guide to identify weak issues within biomethane development strategy. Identification leads to aligning the policies to address the weak issues and promote the growth of biomethane industry.

Assessment of the system functions will lead to the emergence of a functional pattern that highlights the strength and weaknesses of current biomethane strategy. In order to facilitate this understanding, the system functions are characterised by a series of questions.

The set of system functions are:

How strong is the presence of actors in thebiomethane industry?
- Is the number of actors in the value chain sufficient?
- Is the trend of growth of the actors in the value chain inclining or levelling?
- Is lack of actor in certain category forming a barrier for the development of a Biomethane to Grid Technological Innovation System (BTG TIS)?

What is the status of knowledge development and diffusion?
- How broad is the scope of research activities? Does it generate sufficient technical, operational and market-oriented experience concerning the categories of the value chain?
- Is sufficient number of pilot trials conducted?
- How many or how frequently are conferences and workshops being conducted?
- What is the participation level of the actors within the conferences and workshops?

Does the biomethane industry hold growth potential?
- Is the substrate potential of biogas / biomethane generation studied within the countries context?
- Is such a study available to the actors in the value chain?
- Do national targets for biomethane generation exist?
- Is there a national target or recommendation to substitute a percentage of natural gas with biomethane?
- What are the governmental policies in support of biomethane generation and grid injection (environmental or energy security or waste management)?
- Are the regulations for gas quality requirements for grid injection clearly specified?
- Is the procedural requirement to establish a grid connection established and clearly documented?
- Existence of any national targets for vehicle fuel substitution with renewable fuel?
- Are there any restrictions on usage of substrate?
- Is there a national policy regulating the purchase of biogas in gas grids?

What is the status of the market formation?
- Does a niche market application for biomethane exist, or is it being promoted?
- Do financial incentives for biomethane generation and grid injection exist?
- How reliable and extensive is natural gas infrastructure?
- What is the role of natural gas in current energy mix?
- What is the demand pattern for heat and CHP applications?
- Can biomethane drive a proportion of heat and electricity demand?
- How extensive is the CNG / LNG filling station infrastructure?
- Do CNG / LNG vehicles form a growing segment or niche segment?

Is the technology accepted by adopters?

- Is permitting or legal procedure with regional offices causing a barrier?
- What are the activities of lobbying group or promoting organisations?
- Is there an issue of public acceptance against biogas plant construction? Is such an issue being addressed?
- Is more mobilisation of resources needed to promote the biomethane industry?
- Are there any indirect schemes, schemes promoting end use of biomethane e.g. tax benefits on vehicles, investment subsidies etc.?
- Is sufficient skilled human resource available?
- What is the status of government funding of projects in this sector?
- What is the status of access to financing options?

ABBREVIATIONS

AD	Anaerobic Digestion
AEBIOM	European Biomass Association
BioSNG	Bio Synthetic Natural Gas
BTG TIS	Biomethane to grid grid – Technological Innovation System
CH4	Methane
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CO_2	Carbon dioxide
EC	European Committee
EU	European Union
FIT	Feed-in tariff
FLOX	Flameless oxidation
GHG	Green house gas
GWh	Gigawatt hour
IEA	International Energy Agency
IEE	Intelligent Energy for Europe
KTBL	Kuratorium für Technik und Bauwesen in der Landwirtschaft
LCA	Life Cycle Assessement
LEC	Levy Exempt Certificate
LFG	Landfill gas
LNG	Liquefied Natural Gas
Mtoe	Megatons oil equivanent
NREAP	National Renewable Action Plan
PJ	Petajoule
R&D	Research and Development
RED	Renewable Energy Directive
RES	Renewable energy sources
RHI	Renewable Heat Incentive
SDE+	Stimuleringsregeling Duurzame Energieproductie
SNG	Synthetic Natural Gas
TWh	Terawatt hour
UK	United Kingdom
WP	Work package

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RENEWABLE NATURAL GAS TECHNOLOGY ROADMAP FOR CANADA

CANADIAN GAS ASSOCIATION
ASSOCIATION CANADIENNE DU GAZ

December 2014

Glenmore Landfill Biomethane plant in Kelowna, BC
Photo courtesy of FortisBC

Disclaimer

This Technology Roadmap provides the perspective of numerous stakeholders and was prepared under the direction of the Renewable Natural Gas Technology Roadmap Steering Committee. The contents, conclusions, and recommendations are not necessarily endorsed by all participating organizations and their employees or by the Government of Canada.

Acknowledgements

A special thanks to the members of the Steering Committee and their organizations for the dedication and leadership demonstrated throughout the roadmapping exercise. Members met multiple times in person and over teleconference to ensure a fulsome debate and a collective effort were achieved. They also contributed their time and expertise producing draft material that was integral to the assembly of this roadmap.

Lastly, thank you to Stephanie Thorson of Viking Strategies for incorporating the contributions of Steering Committee members into early drafts of the roadmap, contributing her own expertise, and helping to set a course for the final product.

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Canada

Foreward

Society doesn't create the sunshine that energizes solar panels, or the rain that fills reservoirs for hydro-electric dams, or the wind that powers wind farms, but we do make a lot of waste and waste makes biogas and thus biomethane (collectively termed renewable natural gas or RNG).

Of all the types of renewable energy RNG has perhaps the best reasons to be supported and developed. Producing and using RNG will help eliminate what was otherwise a waste product and significant GHG emissions source by turning it into usable energy and in doing so make productive use of a greatly underutilized renewable resource. Turning this loss into an economical and environmental gain is the right thing to do both economically and environmentally. Success will be when RNG becomes business-as-usual for our natural gas networks.

But getting RNG into the grid is proving difficult. Like any "new" product or technology initial costs are higher than established incumbents, markets are uncertain and the way forward is not clearly defined.

Today's challenge is to find a model and approach that makes RNG viable. Technology needs to be understood, supply needs to be developed and to create a sustainable market there has to be real value. This will not happen by itself. To make RNG work, creative ideas need to be explored on all fronts — technological, commercial, social, regulatory and political.

This paper sets out an RNG technology roadmap. It is a step forward to bring us together and follow a common path to make the promise of RNG a reality.

Expertise from many different professions and interests has contributed to this project. So thanks to your efforts, your imagination and your know-how, this roadmap has recommended a way forward and fostered understanding between stakeholders that will help us make this vision real. To all the people who contributed, our sincere thanks.

Table of Contents

The Renewable Natural Gas Technology Roadmap

This Renewable Natural Gas (RNG) Technology Roadmap sets a vision of establishing a viable RNG sector in Canada and explores pathways to achieving the vision. Industry, academic and research groups, and governments have jointly identified market barriers, prioritized the opportunities and technologies and recommended the strategic research and development, and marketing and investment decisions needed for success.

This Roadmap begins by establishing a baseline that sets out the current status of the RNG market in Canada. It then goes on to identify the challenges and opportunities to achieving that vision, and makes recommendations on how to overcome the challenges and exploit the opportunity that is RNG in Canada.

The RNG Technology Roadmap is guided by a Steering Committee comprised of a Chair and leading RNG experts from across Canada. Steering Committee members contributed to Working Groups that addressed key issues identified through the process, the results of which are captured in this roadmap document. Steering Committee Members include:

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1.0 Executive Summary

The proposition for Canadian investment in Renewable Natural Gas (RNG) is strong.

RNG is considered to be a renewable energy form because it is methane produced from organic waste that is captured rather than released into the atmosphere and, as such is carbon-neutral. Once collected RNG can be cleaned to a level that meets pipeline specifications and mixed or used interchangeably with natural gas currently produced from wells.

There is little disputing the benefits that result from using cleaner forms of energy, like RNG, to meet our nation's needs. Reduced pollutants in the air, ensuring a future supply of clean water, and better management of our landmass all contribute to the economic, environmental and social well-being of Canadians.

Yet, the debate over which clean fuel sources are most suitable for the Canadian context continues to challenge investors and policy-makers, and the rapid pace of innovation introduces new and evolving energy solutions every day. Moreover the regional diversity of Canada's energy resource allocations further complicates the debate, with some regions having more fossil fuel resources while others are able to produce more renewable energy resources.

World-renown investor, Warren Buffet is quoted as saying *"Never invest in a business you don't understand".* In other words, play to your strengths. For Canada, this strength would be applying its century-old knowledge on investing and developing the fossil fuel sector toward the production of RNG supply. Add to this opportunity the benefits that Canada's agricultural sector, forestry sector, and municipalities would realize through cost-savings and new revenue streams, and the RNG proposition becomes even richer.

On May 31, 2012, members of Canada's private sector and government institutions gathered in Ottawa, Ontario to bring their collective strength to bear on the opportunity of RNG. The participating natural gas utilities, biogas producers, technology suppliers, research & technology development community, and federal and provincial governments assessed the current state of affairs, debated the hurdles, sought advice from experts across Canada, and charted a way forward.

Discussions between these experts were framed in a technology roadmap exercise with the intent of setting a course for Canada to achieve the vision of **Canada having a fully developed RNG marketplace by 2020 that helps meet the energy needs of Canadians, supports growth and innovation for business, and offers a solution to issues associated with waste and GHG emissions.**

Though the year 2020 may appear as an aggressive target for a fully functioning RNG marketplace in Canada, it's important to note that critical components are already in place. Over 480,000 kilometres of natural gas pipelines are in place to service more than 6.4 million Canadian customers. And growing awareness among consumers has already created opportunities to connect this existing infrastructure and customer base to renewable natural gas supplies.

For example, customers in Abbotsford, British Columbia, have been receiving RNG sourced primarily from on-farm agricultural waste, since 2010 as part of a project between Fraser Valley Biogas and FortisBC. A second project in BC was also opened up at the Salmon Arm landfill. In Ontario, the City of Hamilton established an arrangement with Union Gas in 2011, adding RNG produced from a waste water treatment plant into the utility's distribution network. Finally, green energy provider Bullfrog Power began to offer renewable natural gas environmental attributes to consumers across Canada, sourcing its supply from the EBI Énergie's Dépôt Rive-Nord landfill near Montreal.

Salmon Arm Plant

But many more opportunities are being held up for lack of the appropriate access to feedstock and understanding of the RNG potential. As the recommendations made within this technology roadmap are turned into actions, RNG projects will hopefully continue to multiply and the substantial economic, environmental, and social benefits will be realized by Canadians across the country.

Certainly innovations in pre-treatment facilities, gasification technologies, and upgrading systems will lead to new business opportunities, companies and jobs. Through RNG development value will be placed on low-value waste residues and no-value waste products, creating new revenue streams within the agricultural, forestry, municipal and waste management sectors. RNG, as a renewable energy source will help to offset negative environmental impacts within our energy supply network while extending the availability of our cleanest fossil fuel, natural gas. Communities involved in the sourcing and pre-treatment of feedstock for RNG will benefit from the training and local job creation that will come with a new green energy industry.

But before we can reap the rewards of a fully-developed RMG marketplace, Canada must attend to certain challenges.

- The current production cost premium faced by RNG energy will need to be reduced by a combination of targeted investments in the technology and the application of appropriate policy levers.
- A common understanding among stakeholders of the impacts and value of a RNG marketplace will need to emerge.
- Consistent industry standards and practices for managing feedstock and contractual expectations between renewable natural gas suppliers and distributers will have to be developed.

The challenges to scaling up production of renewable natural gas will vary by producer and chosen technology. It will also depend upon access to sufficient feedstocks.

There is an estimated 1,300 billion cubic feet of RNG supply potential in Canada (equal to 50 per cent of the natural gas consumption in 2012) albeit a much smaller portion would actually be made available to the market.

The forestry sector has the greatest supply potential at 51 per cent given its access to waste forestry biomass. The great potential within the forestry sector comes with great hurdles. Currently, there is no production of renewable natural gas within the forestry sector as the upgrading of gasified biomass to RNG is still an imperfect process requiring strategic technology investments.

Yet, much is being learned from the existing gasification projects and research and development investments in this technology continue. The forestry sector and the federal government are closely collaborating on innovative opportunities, as demonstrated in activities between Natural Resource Canada and FPInnovations, one of the world's largest private, not-for-profit forestry research centres.

The agricultural sector is expected to provide 36 per cent of the total RNG supply potential supported by its access to agricultural and feedlot waste streams. RNG production in this sector is largely based on anaerobic digestion technologies that are well understood and tested. As a result there are fewer

[1] *Potential Production of Methane from Canadian Wastes*, Alberta Innovates – Technology Futures, www.cga.ca/pdfs/RNGpotential.pdf

notable technology barriers to the production of biogas from this sector. However, the low-energy densities of agricultural feedstock, fragmented availability of feedstock resulting from smaller farm sizes, and regulatory barriers in many jurisdictions that prevent the mixing of off-farm feedstock are some of the issues that limit the RNG production potential of this sector. The costs associated with managing these issues, added to the capital costs of a renewable natural gas facility, are deterrents to farm-based RNG production.

The third major RNG supply sector is expected to be the municipal sector (13 per cent of potential supply) based on its access to the municipal landfill waste stream.[1] Municipalities will also play a unique role as a producer and consumer of RNG. Production comes with primary benefits of extracting value from municipal waste and waste diversion. Landfills, source separated organic treatment facilities, and wastewater treatment plants are potentially large sources of feedstock supply. Contaminants, such as the high concentration of nitrogen and oxygen in landfill gas collection systems, will pose some technical challenges to the quality of municipal waste based RNG production. This can be addressed with innovations in pre-treatment systems.

As consumers, municipalities can demonstrate leadership in sustainability by using RNG to heat public facilities and fuel their fleets. Policy levers can be applied to encourage uptake among residents and local industries, as well.

In parallel to scaling up RNG production is the need to raise the awareness among consumers of this carbon-neutral energy option and to apply policy levers that enable and encourage adoption. Among targeted adopters are municipalities, large industry and the power generation sector, and the transportation sector.

As potential RNG consumers that account for more than 50 per cent of current natural gas consumption in Canada, large industry and power generation can play a significant role in the growth of a viable RNG marketplace. Environment Canada's emissions regulation for coal power generation, introduced in 2012, is a signal to other large industry of the role they are expected to play in the federal government's greenhouse gas (GHG) agenda and RNG can be a key part of their response. While not prescribed by Environment Canada, industry's compliance options must be recognized and verified by the department. Currently, renewable natural gas is not recognized and should RNG be recognized, its interchangeability with natural gas would allow industry to become a major adopter and driver for RNG facilities in Canada.

In the transportation sector, renewable natural gas offers an interesting opportunity in that not only can it be blended or used as the exclusive fuel in various forms (CNG or LNG), it has the highest energy conversion of feedstock–to-fuel of the currently available sources of renewable transportation fuels.[2] In Canada, the means to validate the renewable natural gas composition for the transportation fuel sector is not yet established. To realize the benefits of this option, a reliable and transportable accounting mechanism needs to be established. Then, introducing renewable natural gas as a voluntary subscription product would be an attractive method for adoption in this sector.

Recommendations

To overcome the barriers, take advantage of the opportunities, and to realize the benefits presented by a vision of ***a fully-developed renewable natural gas marketplace by 2020,*** this technology roadmap makes the following recommendations:

Recommendation 1: Introduce Policy Tools to Incent the Market

Explore the introduction of government programs and policies that could spur the renewable natural gas marketplace. Further, ensure government recognition of renewable natural gas as an energy end user compliance option for reducing greenhouse gases.

Recommendation 2: Collaborate and Invest in Technology Solutions

Invest in technology priorities, the highest of which is applied biomass gasification research to bring this technology to full commercialization.

Recommendation 3: Provide Education/Awareness to Key Stakeholders

Research and source reliable data to strengthen

[2] Driving performance, measured as km/ha is 23,300 from biodiesel from canola, 24, 400 from corn ethanol, and 67,600 from biogas from corn silage. Data from Biomotion Biofuels, as quoted in *Vehicle Conversion to Natural Gas or Biogas*, Ontario Ministry of Agriculture, Food and Rural Affairs, August, 2012.

the renewable natural gas value proposition and effectively communicate the potential of renewable natural gas in a sustainable energy future for Canada. Further, the RNG industry should develop a central repository for information sharing as a tool to communicate RNG project success and best practices. This repository can be used by potential RNG hosts, project managers and others looking for the necessary steps and information that is critical for RNG project success.

Recommendation 4: Establish Necessary Rules and Standards between Utilities and Producers

Establish gas quality and metering standards, rules for pipeline connection, protocols for sharing data and conditions for accepting renewable natural gas at different points in the gas pipeline system.

Recommendation 5: Determine Green Attributes and Encourage Waste Diversion Policies to Support RNG

Develop a national standard to define, recognize and label the green attributes of renewable natural gas. Further, support energy recovery, and specifically renewable natural gas, as a component of the waste diversion hierarchy.

Recommendation 6: Explore the Use of Renewable Natural Gas for Vehicles

Investigate the natural gas and vehicle market impacts of a renewable natural gas supply for natural gas fuelled vehicles.

Next Steps

Given the recommendations above, the RNG Roadmap stakeholders and broader industry partners will have to assess and prioritize what of the recommendations they wish to implement and in what order. Ultimately, the RNG industry is committed and will work collectively towards achieving the RNG Roadmap vision, that is:

"By 2020, Canada has a fully developed RNG marketplace that meets the energy needs of Canadians, supports growth and innovation for business, and offers a solution to issues associated with waste and emissions."

2.0 What is Renewable Natural Gas

For the purposes of this Technology Roadmap, Renewable Natural Gas (RNG) is defined as methane gas derived from organic materials and waste streams that has been produced and cleaned (had impurities removed) to a level that meets current natural gas pipeline specifications set out by gas utility companies, or that meets natural gas vehicle fuel standards set out by engine manufacturers.

How RNG is produced

There are three main sources of inputs or "feedstocks" suitable for producing RNG:

1. Agricultural and agri-food sources such as unused crop residues, animal manure and food processing waste;
2. Forestry bi-products such as wood waste generated during harvest operations;
3. Municipal solid waste and bio-solids from wastewater.

RNG can be produced from these feedstocks using either *anaerobic digestion*, an established technology best suited for producing RNG from relatively wet feedstock and *gasification*, which is a rapidly developing technology best suited for producing RNG from relatively dry feedstock.

Anaerobic Digestion (microbial process)

Anaerobic digestion (AD) is a natural process of decomposition of organic materials by microbes in the absence of oxygen, in which biogas is produced. Anaerobic digestion occurs in landfills and sewage treatment and in industrial processes to convert manures, agri-food residues, industrial by-products and sorted municipal wastes to biogas.

The resulting biogas contains a much lower methane concentration than conventional natural gas[3] and can be used on-site with minor processing for its heating value or to run an electricity generator. However, upgrading technologies are available that can produce a clean, high energy RNG suitable for direct injection into existing natural gas pipeline infrastructure and able to be mixed with conventional natural gas.

Gasification (thermal process)

Biomass gasification is a high temperature (>500 °C) process in which organic material is converted into syngas in the presence of oxygen and/or steam. The syngas can be converted into RNG through a process called methanation and then be introduced into the natural gas pipeline infrastructure and mixed with conventional natural gas.

Gasification of coal is used on a large scale in power plants, where syngas is used as a fuel in gas turbines. Gasification of biomass material (such as wood waste) is in its development phase but progressing rapidly.

Gasification has some advantages over anaerobic digestion. First, a wider variety of non-homogeneous feedstocks that can be utilized, almost any type of organic material can be used as gasification feedstock, including forestry and agriculture residues, and sorted municipal waste. Second, the methane yield is higher. Production of methane from biogas through anaerobic digestion generally converts 20 per cent of the material while gasification, depending on the process and material utilized, can achieve from 65 per cent to 80 per cent conversion yield.

[3] Biogas is typically comprised of 50 per cent-60 per cent methane (CH_4), 40 per cent-50 per cent carbon dioxide (CO_2), with varying levels of hydrogen sulfide (H_2S) and other trace compounds.

3.0 Canada's Renewable Natural Gas Opportunity

This section includes a vision for RNG in Canada, describes the infrastructure and supply foundations on which this vision can be realized and outlines some of the operational RNG projects in Canada for context.

Vision for RNG in Canada

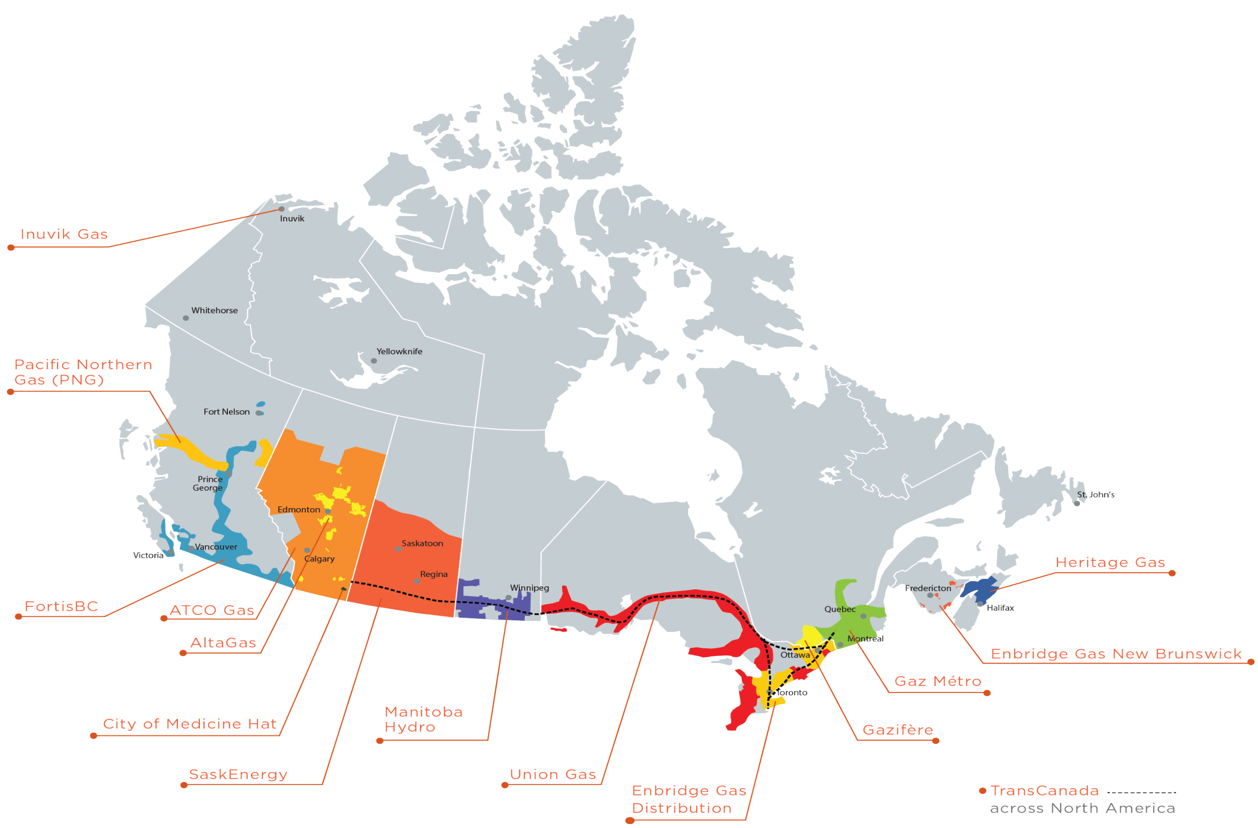
By 2020, Canada has a fully developed RNG marketplace that meets the energy needs of Canadians, supports growth and innovation for business, and offers a solution to issues associated with waste and emissions.

The Foundation – The Natural Gas Pipeline Infrastructure

The Canadian natural gas pipeline system is part of the larger North American natural gas market – a fully integrated system connected by over 4 million kilometres of natural gas transmission and distribution pipelines that fuel over 200 million homes, businesses, institutions, and industries all over the continent. This system links vast natural gas supply sources to demand centres across North America, and the pipeline transmission and distribution network operates with nearly 100 per cent reliability.

Natural gas has an established history in Canada, with the first well being drilled in Alberta over 125 years ago. Since this time, Canada has grown to be both a significant producer and consumer of natural gas. In fact, Canada ranks third globally in natural gas production. Currently, natural gas meets over 30 per cent of Canadian domestic energy needs, second only to petroleum products.[4] This versatile fuel is the single largest source of energy for Canadian homes and industry and is a growing source of input fuel for the generation of electricity and in transportation.

The extensive Canadian pipeline and underground gas storage network and the interchangeability of RNG with conventional natural gas means that in many cases, RNG can be introduced at its point of production, and transported and transported/delivered to the end user without a significant modification to pipeline infrastructure or to the end user's natural gas burning equipment.



[4] "The Facts on Canadian Natural Gas", Canadian Natural Gas, www.canadiannaturalgas.ca/media-library/factsheets/natural-gas-fact-book

The Foundation – Canada's RNG Production Potential

Over the past 25 years, governments and industry have made significant investments in developing and producing energy from renewable sources including biomass, solar and wind. However, there has yet to be a targeted push towards harnessing renewable energy in the form of RNG despite the size and potential of the RNG resource as a renewable fuel option for Canada.

Estimates from the 2010 Alberta Innovates Technology Futures (formerly the Alberta Research Council) study, *"Potential Production of Methane from Canadian Wastes"*, suggest the Canadian potential is equivalent to 1300 billion cubic feet (bcf) per year[5] – slightly over half the current annual consumption of gas (2500 bcf/year) in Canada.[6]

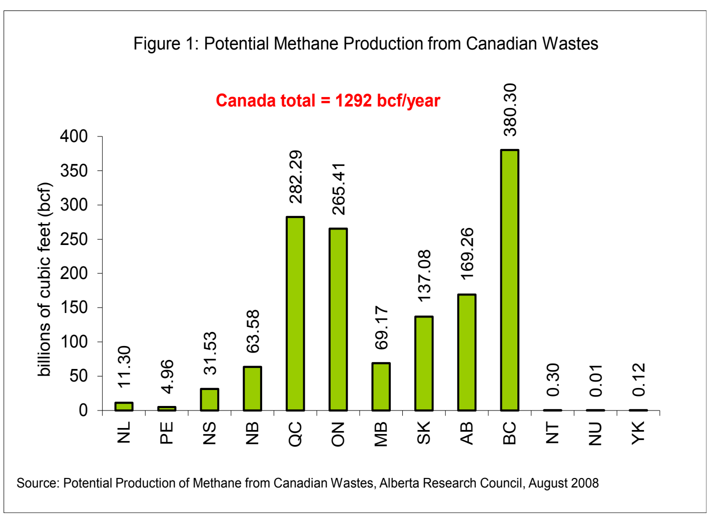
The use of gasification has the potential to produce most of the RNG in Canada (84 per cent of the total) while anaerobic digestion has the potential to produce 16 per cent of total. While AD could ultimately contribute a much lower percentage of the total RNG supply, it is still significant because of the greater availability and lower cost of AD-based RNG production technology.

From a regional perspective, the largest potential for RNG exists in British Columbia, followed by Ontario and Quebec due primarily to their large biomass resource base.

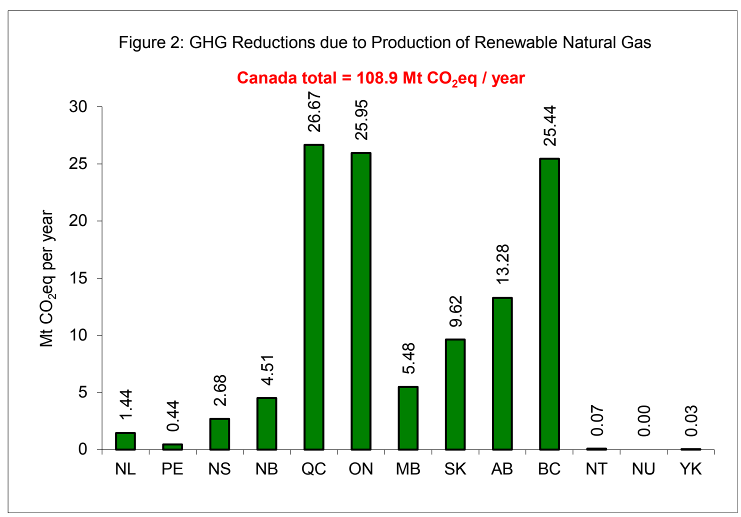
From a GHG reduction perspective, Canada's RNG potential could offer reductions of 108 metric tonnes of carbon dioxide equivalent (MT CO2/eq). If just 10 per cent of this total was realized it would be equal to the removal of 1 million cars from Canadian roads or meeting approximately 10 per cent of Canada's Copenhagen Climate Change Commitment to reduce GHG's by 17 per cent by 2020 (from 2005 as a baseline year).

CANADA's RNG POTENTIAL

RNG Production Potential



RNG Carbon Offset Potential



10 per cent of the potential is gas for 1 million homes in Canada

10 per cent of the potential = 1.8 million cars off the roads

[5] *Potential Production of Methane from Canadian Wastes,* Alberta Innovates – Technology Futures, www.cga.ca/pdfs/RNGpotential.pdf

[6] Salim Abboud et autres, Alberta Research Council et Association canadienne du Gaz, *Potential Production of Methane from Canadian Wastes*, septembre 2010, p. viii

The Foundation – Building on Current Operational RNG Projects

While the potential for production of RNG in Canada is significant, the number of projects in operation remains limited due to lack of awareness and higher initial costs associated with the early phase of RNG development in Canada. The current projects in Canada are summarized in Table 1.

The Berthierville project was the first to begin operation in Canada and is currently injecting RNG into the Trans-Quebec Maritime (TQM) pipeline in Quebec.

Fraser Valley Biogas in Abbotsford (formerly Catalyst Power Inc.) combines anaerobic digestion and a biogas upgrading plant to produce RNG primarily from on-farm agricultural waste. A small amount of off-farm waste is delivered from a local food-processing plant. FortisBC operates the interconnection facility at this project, monitoring gas quality and connecting this source of RNG directly to its customers. It began producing RNG in 2010.

The City of Hamilton, ON has been utilizing the biogas from the anaerobic sludge digestion at the Woodward Avenue Wastewater Treatment Plant to generate electricity since 2006. In 2011, the City of Hamilton began producing RNG with excess biogas generated at the site and injecting it into Union Gas's nearby distribution system.

At the Salmon Arm, BC landfill, FortisBC and the Columbia Shuswap Regional District (CSRD) partnered to upgrade and inject RNG derived from landfill gas into the local distribution system. In this case, FortisBC is purchasing raw landfill gas from the CSRD and it will own and operate the gas purification plant in addition to the interconnection facility and gas quality monitoring. It was commissioned in 2012 and first injected RNG into the pipeline in March 2013.

Table 1. List of Canadian RNG Projects

PLACE	SUPPLIER	SUBSTRATE	TECHNOLOGY	PLANT CAPACITY (Nm3/h raw gas)	iN OPERATION SINCE
Berthierville (QC)	UOP	Landfill gas	Membrane		2003
Abbotsford (BC)	Greenlane	Codigestion	Water wash	750	2010
Hamilton (ON)	Greenlane	Wastewater treatment gas	Water wash	800	2011
Salmon Arm (BC)	Xebec	Landfill gas	PSA	300	2013
Kelowna (BC)	ARC Technologies	Landfill gas	PSA	900	2014
PLANNED					
Delta (BC)	Greenlane	Codigestion	Water wash	400	2014
Chilliwack (BC)	Unknown	Codegestion	Unknown	400	2015
Richmond (BC)	Unknown	Wastewater treatment gas	Unknown	150	2016

4.0 Challenges to Meeting Market Potential

Successful RNG projects are those for which there is a positive alignment of a range of factors. This chapter outlines the challenges associated with building stakeholder awareness and around individual factors of project economics and costs, regional differences, pipeline access, feedstock, and technology.

Stakeholder Awareness

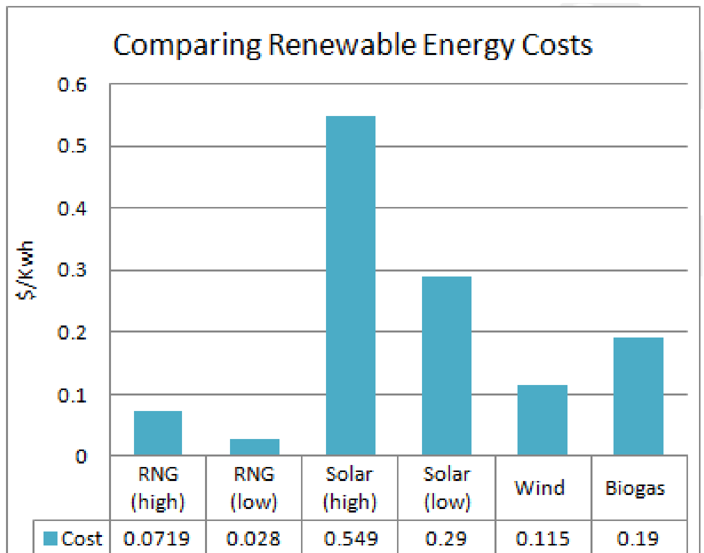
Building awareness around the potential for RNG in a sustainable Canadian energy future will be front and center to the long term success of RNG. While the waste management potential of producing RNG from manures, residues, agri-food wastes and sorted wastes is attractive, both public opinion and regulations indicate concerns about contamination of the environment and the proliferation of pathogens. As indicated in the recommendations of this report, the RNG industry should collaborate to develop a common set of messages and materials that could be used by the industry to engage and educate the key decision-makers and stakeholders who will be instrumental in realizing Canada's RNG potential.

RNG Project Economics & Costs

The cost of RNG varies significantly depending on the scale and location of a project. Generally, larger landfill projects have RNG supply cost estimates as low as $8/GJ. RNG supply costs for smaller projects, such as small-scale farm-based anaerobic digestion projects, are upwards of $15-20/GJ. The main drivers for the higher cost of RNG include costs associated with collecting feedstock and the capital equipment costs to removing impurities from the biogas in order to bring it to pipeline quality RNG. In the case of landfills, costs are associated with collecting and upgrading raw biogas and connecting to the pipeline. For other applications, costs can be broadly categorized into four components: converting feedstock to gas; upgrading; metering and monitoring; and connecting to the pipeline. The costs associated with each of these components will vary depending on the volume of gas and location of the facility.

Access to the gas pipeline network is an important cost consideration. Terrain and existing local conditions such as roads and existing infrastructure, also need to be understood. For projects that are too distant from the pipeline system, there is the option of compressing the RNG to use on site or for delivery by truck to natural as consuming markets.

To understand the full value of any RNG project the cost of RNG should be compared to other renewable energy options in addition to comparisons with the current market prices for natural gas.[7] The figure below presents various renewable energy costs include large and small scale RNG projects, wind power, solar power (small and large scale) and electricity generated from biogas. What is shown is that RNG is a cost effective renewable energy option when compared to prices offered for renewable feed in tariff (FIT) electricity sources.



Sources: RNG costs are estimates ($8/GJ and $20/GJ) based on various project sizes. The RNG $/Kwh values, above, are based on heating value of the gas. All other renewable costs are from Ontario's FIT Program for electricity.

Regional Differences

RNG is a new commodity in Canada and regional differences persist. Variations in provincial regulation of local distribution companies, terminology, and RNG quality management requirements are all challenges facing the RNG sector. But since utilities operate within a regulated environment, tariffs and rates to recover costs from customers must be approved by regulators. This includes and

[7] The market/spot price for natural gas varies depending on continental supply and demand. The average price in 2008 was $8/GJ and has fallen in recent years to $3/GJ due to robust supplies of natural gas. More information on the affordability of natural gas prices can be found here: http://www.cga.ca/

tariffs for treatment of RNG. Not surprisingly most Canadian utilities and regulatory authorities have not established tariff structures specific to RNG and the investment required to connect RNG into the natural gas system. Without an approved tariff, utilities cannot recover any associated cost such as any price differential between RNG gas supply and conventional natural gas supply.

Given that energy utility regulation is largely a provincial concern, there is no commonly accepted approach or standard to guide RNG suppliers looking to connect to the existing natural gas systems. Each project can have significant differences in items like supply pressure, piping material, safety features and connection points that can vary across utilities. Further, RNG projects face different jurisdictional codes, standards and environmental regulations including codes for pressure vessels, pressurized equipment, and environmental approvals and permits. Some of these codes and standards are well understood having been well established and used in industrial applications for many years. Other requirements may be imposed on an ad hoc basis by jurisdictions that have less experience with natural gas or that are unfamiliar with RNG.

Pipeline Access

Gaining access to the pipeline distribution network is a key hurdle for any RNG project. Access must be facilitated by a willingness of the gas utilities to have RNG in their networks. Canadian gas utilities Enbridge Gas Distribution, FortisBC, GazMétro, and Union Gas have all demonstrated willingness to accept RNG, though each has their own technical specifications for gas quality, grid connection and capacity management.

Utilities need to ensure the quality of the gas in their systems as this affects the reliability and potentially the safety of the system. Utilities must consider the impacts of the RNG product on their pipeline networks before considering RNG additions to the pipeline.

Prior to RNG being injected into a pipeline, it must meet the pipeline's established gas quality standards, particularly any limits regarding trace components, and heating value of the RNG. The technical specifications in the Bureau de normalisation du Québec (BNQ) standard[8] and Canadian Gas Association (CGA) guidelines[9] are very similar and a number of utilities have a list of criteria available. The CGA guidelines are available on the CGA website.

Responsibility for gas quality analysis, metering of the volumes accepted and its odourization and other safety measures are also the responsibility of the utilities. Analysis and metering can become a barrier if it is not clear what the measurement standards are or what the required protocol are for access by the utility to RNG metering equipment and other exchanges of data between the RNG producer and the utility distributor.

A further element affecting RNG access to the distribution network is capacity management. Capacity management refers to the ability of the grid at the injection point to accept the full RNG production at all times of the year. Grid connection becomes a barrier if there are no clear and appropriate criteria defining when and how a producer can get connected, or what volume of RNG they can inject into the network. This would include criteria for handling potential interruptions in RNG injection and rules for compensation in those situations. The grid carrying capacity must be accurately evaluated particularly to understand situations when gas consumption is at its lowest (warm summer nights, for example) and RNG production may be at its peak. It is reasonable to expect times when no RNG can be injected due to scheduled network downtime, breakdown, capacity-sharing, or quality reasons.

Feedstock

Achieving Canada's RNG supply potential will require a dedicated effort by the industry to contract with and compete for available RNG feedstock supply. Feedstocks such as biomass are already valued for their ability to generate other forms of energy, namely power and heat.

The potential limitation to achieving crucial economies of scale that is imposed by feedstock supply is most notable in the agricultural and agri-food sectors. Scale can be increased by

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[8] *BNQ 3672-100/2012 Biométhane : spécifications de la qualité pour injection dans les réseaux de distribution et de transport de gaz naturel, Bureau de normalisation du Québec,* juillet 2012

[9] *Biomethane Guidelines for the Introduction of Biomethane into Existing Natural Gas Distribution and Transmission Systems*, Association canadienne du gaz, février 2012.

acquiring low cost feedstock. However, many Canadian jurisdictions do not have clear regulatory pathways to mix off-farm material with manure and agricultural bi-products while still maintaining the agricultural designation of the farm or of the effluent digestate. Those jurisdictions that do have clear regulations require pre-processing of the off-farm material to neutralize pathogens which adds a processing cost.

In general, manure has a low energy density, meaning that if you want to consolidate larger volumes for RNG feedstock it may only be economical to transport it less than two kilometres. Similarly, agricultural crop residues are generally light and fluffy, and also of low energy density. Consolidating sufficiently large volumes of agricultural-residue RNG feedstock from several producers to one site can be expensive.

Courtesy of FortisBC

Urban organic waste and food processing bi-products are feedstocks that can be available on a larger scale, enabling larger biogas systems that match the scale needed for economic biogas upgrading.

Municipal solid waste operations are not yet contributing to RNG supply. There is a growing trend to sort municipal wastes and to assign particular waste streams to different processing. While the intention is to relieve landfill capacity by such waste diversion, the sorting and processing is more costly than previous landfilling. For large municipal waste-based biogas systems the difficultly may be to find suitable locations because of zoning limitations and proximity to concerned neighbours. The added costs of extensive odour control systems or significant setback distances are required to minimize potential odour impacts for neighbours. Of particular concern are the material unloading and handling buildings. Environmental assessments and meeting the requirements to have authorization certificates can be a significant expense.

For facilities that look to use gasification of biomass to produce RNG, challenges arise from the reduced scale of production and the wide variety in the quality of the biomass feedstock. Even with seemingly uniform biomass inputs like wood chips, a premium forestry sector feedstock, there can be major differences in characteristics and properties among batches, due to different chippers, different material, and different moisture content. The cost to securing an acceptable consistent quality of long term biomass supply is a key barrier to RNG production from gasification.

Technology Limitations

Each RNG project site is different and most project developers will have specific priorities for their project, including integration into existing farm or waste treatment facility operations. The financial viability of RNG projects must be clearly established at a project's outset to attract funding. In general, the adoption of low-cost AD-based systems that result in lower energy yields or RNG projects that require more operational effort (for instance, when controls are not all automated) put the viability of these projects at risk. Technology solutions do exist for these shortcomings. Developers can retrofit advanced controls or equipment onto systems but this changes the economics of projects that were initially lower cost.

The RNG production technologies, process design, and facility layout to produce pipeline quality RNG vary depending upon the biogas stream that is available. Processing of both the biomass inputs and biogas output continues to be a significant capital and operating expense for any RNG project. The size of available commercial RNG upgrading equipment does not reflect the scale of farms that operate in many parts of the country. The lack of smaller sized upgrading equipment limits the number of farms that can collaborate to produce RNG. There is an identified need for the fabrication of smaller units to meet smaller amounts of available on-site RNG feedstock.

A key technical challenge to biomass gasification is in raw syngas cleaning to remove chemical and solid impurities that impact the process of converting the syngas to methane and, in turn, RNG. The most challenging contaminant to deal with are the tars that are formed during the chemical reactions in the gasification process. While the use of very high temperatures for gasification generally reduces the amounts of tar produced, this increases the cost of the equipment and the operation. Ongoing research into making the gasification of biomass into syngas suitable for an RNG process is focusing on using oxygen and chemical reactor designs that reduce the formation of tars by retaining the tar precursors for longer periods at high temperatures. Syngas cleaning can cost more than feedstock procurement and initial gasification.[10]

Current research activities in gasification reactors and the cleaning of raw syngas in biomass gasification are looking to respond to these performance concerns.

[10] Salim Abboud et Brent Scorfield, Potential Production of Renewable Natural Gas from Ontario Wastes, Alberta Innovates Technology Futures, mai 2011

5.0 Achieving the Renewable Natural Gas Vision

This section describes the contributions that potential RNG producing and consuming sectors can make to achieving Canada's RNG market potential. The sectors discussed below include large industry and power generation; transportation; residents and businesses; farms and the agri-industry; forestry; and municipalities. Municipalities can act both as consumers and producers and are treated separately.

Large Industry and Power Generation

Large industry is a significant consumer of energy, accounting for 30 per cent of all Canadian energy demand in 2011.[11] The dominant fuel used is natural gas, which meets a third of industrial energy needs, mainly for heat requirements.

This energy use profile of large industry, combined with its existing pipeline connection to natural gas supply, make this sector ideal for RNG consumption. Further, by 2020 many large energy consuming sectors will be required by federal regulation, led by Environment Canada (EC), to reduce their greenhouse gas emissions, again making them a perfect target for RNG use. The first such regulations came into force in 2012 for coal-fired power plants. The next sectors to be regulated include oil and gas (oil sands, gas processing plants, oil refineries) and natural gas-fired power plants, followed by various large industrial sectors. The method, or compliance options, by which an industry reduces its emissions is not prescribed by EC, however compliance options must be recognized and verified by EC.


Plant

In addition to federal GHG reduction regulations, a number of provinces have in place or are advancing regulatory mechanisms to reduce GHG's including in British Columbia, Alberta and Quebec where carbon taxes are paid by consumers and/or industry. Also, Quebec is part of the Western Climate Initiative, a carbon cap and trade system with California. Further, most provinces and territories have or are examining commitments to reduce the GHG emission levels.

For industry, RNG is an attractive low carbon option given it is 100 per cent interchangeable with natural gas. This interchangeability would allow industry to remain in operation without having to shut down to replace or upgrade equipment. Using RNG also does not trigger the technology risk associated with changing a successful process and/or introducing new equipment or process steps. This is a significant consideration in a capital constrained financial environment. Further, industry would be supporting a renewable, domestic, green energy source while helping to monetize and manage waste streams.

However, there are a number of challenges and barriers that must be addressed before large industry can become significant consumers of RNG in Canada. RNG is relatively new in Canada and to date there has not been a concerted effort to educate Canadian policy makers and the general public on the product. There is a considerable lack of understanding about what RNG is, what the RNG potential for Canada is and the role RNG can play as a carbon-neutral fuel. Simply put, raising RNG awareness has not been a focus for government bodies and the use of RNG as a method to meet GHG reduction regulations has not been accepted by most governments in Canada. Second, there is the need for more fulsome dissemination of RNG project economics and costing information to allow potential RNG end users and customers to compare the cost of buying RNG or financing an RNG project to alternative compliance options such as new equipment upgrades or other efficiency investments and programs.

[11] Statistics Canada, Report on Energy Supply and Demand

Transportation

RNG is increasingly being used as a transportation fuel. The drivers for this are regulation and taxes on waste disposal, increasing the need for renewable fuel sources. In Europe, the European Commission's Biofuels Directive measures to improve local air quality, and the need for clean transportation fuels in urban areas has helped push RNG adoption.[12] Similar regulations and treatment for transportation uses of RNG compared to natural gas and fossil fuel options are not established in Canada.

That said, natural gas is currently significantly cheaper than gasoline and diesel fuel in Canada and as a result there is already a significant supply side response to the increasing market interest in using CNG and LNG for heavy duty and light duty vehicles. But given the lack of public refueling infrastructure, companies that invest in these vehicles must also install refueling stations. Return-to-base vehicles, usually fleets, are well suited to CNG or LNG and would enjoy similar cost savings.

Since RNG can be used interchangeably for natural gas and since RNG can be injected anywhere on the natural gas grid and wheeled to LCNG filling stations through gas marketing contracts, the demand potential for RNG from this market is apparent.

RNG is the environmentally preferable vehicle fuel because it essentially captures and neutralizes previously emitted methane and converts it into a high energy fuel. This methane capture and neutralization means a little RNG goes a long way in reducing GHG emissions. For example, if a transportation end user were to blend just 10 per cent RNG to their CNG or LNG, the carbon reduction benefit of switching from diesel to LNG or CNG is enhanced, bringing the total GHG benefit to approximately 50 per cent versus diesel or gasoline.

An attractive method to encourage the uptake of RNG as a transportation fuel is to include RNG as a "voluntary subscription" product. Since the RNG would be sold through the established mechanism of gas market contracts, any "subscribed" percentage of renewable RNG content can be blended in to accommodate the consumer's needs for a specific RNG content. Any percentage of RNG content in the vehicle fuel can be accounted for directly at the fuel pump. As this would be an optional product offering, pricing will be determined by market-driven demand. In jurisdictions like BC and Quebec where carbon taxes or emission caps are in place, consumers can benefit from avoided carbon costs, currently at \$30/ton CO_2e and \$10/ton CO_2e respectively.

Creating a flexible and transportable RNG product aligns with the initiatives outlined in the "*Deployment Roadmap for Natural Gas Use in the Canadian Transportation Sector*", which was facilitated by Natural Resources Canada, and involved a range of stakeholders. Some organizations and associations are helping promote RNG as a vehicle fuel such as the Biogas Association who has published a guide for the agricultural sector in 2013 called "*Farm to Fuel: Developers' Guide to Biogas as a Vehicle Fuel*". Despite the significant potential for natural gas and RNG to make a meaningful contribution to Canada's commitment to reducing GHG's, there remain technical, cost and policy impediments to large scale market adoption. Through this Roadmap, the industry will look to collaborate on solutions that will eliminate the technical and market barriers to wider adoption of natural gas and RNG for vehicles in Canada.

Residents and Businesses

Currently a number of individual consumers and businesses voluntarily pay a premium to certain renewable energy providers or their local utility to support and actively participate in the growth of renewable energy in Canada. In 2011, Bullfrog Power became the first entity to launch a RNG environmental attributes offering to consumers across Canada. FortisBC also offers its customers an option to buy RNG. The growing voluntary market for renewable energy in Canada and the US proves

[12] National Society for Clean Air and Environmental Protection, Biogas as a Transport Fuel, juin 2006 http://www.cleanvehicle.eu/fileadmin/downloads/UK/nsca_biogas_as_a_road_transport__084926300_1011_24042007.pdf

that consumer demand can play a vital role in the development of the RNG market in Canada.

The biggest barriers to widespread adoption of RNG among residential and small and medium enterprise (SME) customers are the cost, the availability of RNG, and the lack of awareness among consumers. Several specific strategies and tactics can be used to overcome these barriers and increase RNG adoption in these sectors.

One of the easiest ways to reduce the cost barrier is to offer a blended product. This is possible because of the interchangeability of RNG with natural gas. This could be achieved in a manner similar to what FortisBC has done, where customers choose to pay for a 10 per cent blend of RNG. Or it could be achieved by blending RNG into the overall gas supply. In either case, the full price premium of RNG is diluted by mixing it with the costs of conventional natural gas. By overcoming the cost barrier in these ways, utilities can make RNG available to their customers.

Awareness can be tackled in a similar manner to any new product introduction. FortisBC began marketing RNG by targeting messages to those customers who are more likely to take action – namely, their "green" customers. By targeting those early adopters, it is easier to build support for broader uptake. Customer recognition for early adoption and participation can also be a good tool.

Targeting customers in areas where RNG is produced can also be effective, since residential customers are likely to have a stronger connection with the projects, and a stronger interest when they feel they are investing where they live.

Producers

The main sectors that have potential to produce RNG are the farm, agri-industry and forestry sectors and municipalities.

Farms and Agri-Industry

Farm-based and agri-industrial biogas systems will be an important near-term contributor to the supply of RNG. While other sources of RNG are limited in their number and location (landfill and sewage biogas), or maturity of technology (gasification), the opportunity to deploy farm and agri-industry biogas systems widely today is largely limited by RNG offtake prices. Experience with electricity-based biogas systems in Europe has shown that feedstock supply, technology scale, and access to capital are not significant barriers when suitable financial incentives are in place.

Building farm-based and agri-industrial biogas systems at a large enough size to achieve improved economies of scale will be an important first step in this sector becoming a significant RNG production source. There are two potential approaches to achieve this critical size:.

1. <u>Develop Large Farm-Based Systems</u>
Securing sufficient feedstock supply in rural areas to achieve minimum efficient size can be achieved in several proven ways:

- *Mix off-farm materials with agricultural inputs*: Certain jurisdictions in Canada have established regulatory approvals which allow the mixing with up to 50 per cent off-farm materials. Although uncommon today, several medium-sized livestock facilities can economically combine their manure, transporting it by either by pipe or by truck, as long as they are within approximately five km of each other. Farms can also secure larger supplies of off-farm materials from food processors and organic waste suppliers, potentially enabling many mid-sized livestock farms to establish RNG projects. Thus, supply of inputs is not constraining in this context.
- *Use high-output agricultural energy crops:* Germany has paved the way demonstrating the use of corn silage as an energy crop fed directly into the RNG system. Using energy crops as an input means the siting of the RNG system is relatively independent of other constraints and can be sited according to where pipeline capacity allows interconnection. In general, using energy crops as the input to RNG production results in a higher cost of production because of crop production costs, compared to waste inputs.

2. <u>Develop Large Agri-Industrial Systems</u>
Recent developments in the regulations that control waste processing combined with the costs associated with conventional processing of wastes (i.e., landfilling of the entire unsorted municipal waste stream) have created an opportunity to use anaerobic digestion technology to process sorted wet organic wastes to create biogas suitable for RNG production.

Building biogas and associated RNG production systems at host waste generation sites or in industrial areas has the advantage of capitalizing on on-site synergies such as waste heat sharing, availability of existing on-site advanced technology for waste management and handling, or separating different streams of mixed waste. There are several models for this approach:

- *Locate at host waste generation sites*: Using on-site generated waste such as brewery or slaughterhouse waste, and reducing organics in wastewater, can build on cost savings from reduced sewer discharge fees. Typically, food companies will not bring in waste streams from other locations because of various limitations (space, waste approvals, non-core business activity), resulting in limits on the size of possible RNG systems.
- *Create waste management biogas systems*: Large waste management biogas systems have the opportunity to install large-scale materials separation equipment allowing variable waste streams to be used, including those with plastics and packaging contamination. By being located in existing industrial areas, there will often already be significant air emissions controls in place to minimize nearby nuisance issues. This type of system can be built large enough to employ existing biogas upgrading equipment competitively, and is generally only constrained by the market value of RNG compared to other green energy opportunities such as electricity generation.

Digester Pipes

Technology Considerations

RNG technology for the farm based and agri-industrial sectors is reasonably mature. These sectors have witnessed significant growth of RNG production around the world since the 1990's which has in turn signalled the market to develop innovative products. However, there remain opportunities to improve RNG project economics and the biogas and RNG production/cleaning processes through the development of more standardized equipment, for both AD and upgrading. Further, other areas for AD technology improvements include N2/O2 removal efficiency for landfill gas and improved digester stability and efficiency.

Forestry

Forest products residue streams can be used to produce RNG through both gasification and methanation. While this is a longer term opportunity, it has the potential to deliver significant domestic value, and should be considered an alternative to producing and shipping wood pellets to distant markets.

The gasification pathway would be the process of choice for RNG production from forestry residue. Gasifier manufacturers, which include some Canadian companies, could team up with Canadian consultants, research centres and universities to develop a first Canadian forestry-residue based RNG gasification demonstration project. Such collaboration could benefit from European experience in RNG production from biomass. A demonstration project would contribute to improving the Canadian RNG production portfolio and help the commercialization of this technology pathway for RNG production in Canada. It would also serve to address the remaining technological issues, which consist mainly of feedstock quality management, gas cleaning, and process integration.

Managing Feedstock Supply

RNG production from forestry residue on a large scale should be done in partnership with the regional forest products industry. RNG production should not adversely impact the forest products industry, but rather act as a revitalizing element.

Stakeholders have identified inconsistent feedstock quality as a concern given the range in woody biomass sources. One solution would be to implement a feedstock quality control process.

The integration of RNG production in this sector with existing combined heat and power (CHP) plants or pulp mills should be evaluated as potential approaches for utilizing excess heat from the RNG process. A co-location site will likely offer numerous advantages for an early demonstration plant, such as sharing existing infrastructure and skilled technical support, and providing additional revenue streams to the site. Co-location within an existing facility is likely to reduce both technical and financial risk. The costs of large-scale future plants will decrease with additional large-scale experience.

Technology Considerations

Forestry-residue based gasification technologies are being pilot tested in several jurisdictions. The International Energy Agency (IEA) Task Force 33, has an interactive map/database of gasification projects and the associated manufacturers around the world. A technology brief is included in each project summary.

Priority areas for collaboration among governments and industry include applied research and technology development related to biomass gasification, non-precious metal catalysts, syngas cleaning technologies, and integration of biomass gasification systems

It is important to consider that within the forest sector that RNG will need to compete with the other uses for the forestry-residue biomass. This includes uses such as combined heat and power production and/or the production of other bio-fuel and bio-products. Ultimately, the successful technology will be the one that offers the highest rate of return.

The forest sector is continually evaluating technologies and products which will improve the profitability of their operations. Therefore, improving technologies that gasify, methanate and clean biomass syngas are technology priorities for the RNG industry.

Municipalities

RNG has multiple benefits for municipalities, both from the supply side and the demand side. On the supply side the main benefits are extracting value from waste, reducing liability for landfill operations through waste diversion, cutting landfill GHG emissions and strengthening the local infrastructure and economy. As sustainability and good stewardship choices are top of mind for many local governments, the main benefit will be the possibility of greening their operations, for example by using RNG in heating of buildings or for transportation.

Municipal RNG Supply

Landfills, source separated organic (SSO) treatment facilities, and wastewater treatment plants (WWTP) have, collectively, been identified as large sources of biomass feedstock and in turn RNG supply in Canada.

Raw landfill gas is already being produced at large scale, and is the most cost-effective near-term source of RNG. Currently, landfill gas is usually captured and flared to meet environmental regulations, or burnt for its heating value, or used to generate electricity on-site. However, for landfills that are located near a natural gas pipeline and are of sufficient scale, RNG production may be the preferred option. Harnessing the energy content of urban organic waste allows municipalities to realize the economic, environmental and social benefits for residents and businesses.

Landfills are considered to be a preferred location for municipal digesters because of the following factors: preferential zoning; existing collection infrastructure; less concerns about odour and more experience with its control and containment; existing waste management expertise and equipment; availability of space and generally lower cost of land; ability to handle condensate; and integration with existing landfill gas collection improves economies of scale.

In Quebec, the provincial government is investing in municipal AD facilities and is phasing in a ban on sending biodegradable organics to landfills. This will help divert this material towards RNG production in that province. In Ontario, some industry associations are working with relevant government ministries on examining a similar ban on putting biodegradable organics in landfills. In BC, leading municipalities such as Metro Vancouver and Surrey are phasing in bans on biodegradable organic waste.

The small scale collection of SSO in many

Canadian communities limits the usefulness of this waste stream for RNG development. Communities that allow the mixing of yard waste with SSO may render the SSO unusable for AD, so separate SSO collection is best for RNG. Further, new SSO facilities can be located close to suitable pipelines.

Landfills have established collection infrastructure and many have collection systems already in place that can be used for RNG production, provided they are located near a suitable natural gas pipeline. SSO treatment facilities can also be co-located with landfills to maximize the economic investment in upgrading, compression and injection equipment. MSW gasification plants may also be well suited to these locations.

The energy potential from WWTP will continue to grow with population growth. The feedstock challenge in this case is that some communities prefer to operate smaller, decentralized treatment facilities, which affect the economics of RNG production.

Technology Considerations

Landfill gas has high concentrations of nitrogen and oxygen due to the intake of air by the gas collection system. This restricts the technologies that can be used to produce RNG from this feedstock source, driving their capital and operating costs higher. This can be mitigated by the scale of landfills because larger landfill projects are more cost effective.

Some SSO collection systems are heavily contaminated with material such as plastic bags, diapers and personal hygiene products. However, technology providers have developed pre-treatment technologies to overcome this hurdle, so municipalities can accept a wide range of organic waste and maximize resident participation.

Municipal RNG Consumption

Municipalities are potentially large RNG consumers as well. Some of the challenges to increasing RNG consumption within municipalities centre on the higher cost of RNG versus incumbent energy options and a general lack of awareness of the RNG option.

As described previously, blending strategies can be used to reduce the cost impact of RNG adoption. Additionally, a municipality could designate 100 per cent RNG for use at a single facility such as a community centre or City Hall, while still using traditional natural gas at its other facilities. A municipality could also promote access to RNG for local industries to draw in new businesses to their locality. Local industries would be able to use RNG to meet any upcoming GHG regulations without threatening their competitive position with having to make large capital investments in other forms of emissions abatement.

Improved RNG awareness can be built around the benefits of closing the loop for municipalities between treating the waste generated by their residents and businesses, and generating RNG based energy for local use. The production of RNG from diverted wastes should be identified as superior to other processes that do not produce an energy stream. An example of this approach can be seen in Surrey, BC where the plan is to use the RNG produced from feedstock provided by its source separated organics (SSO) facility to fuel waste trucks, starting in 2014.

Educating municipalities about the environmental, economic and social benefits of RNG, and pointing to other jurisdictions that have taken the lead, will encourage other municipalities to take action. This can be done through meetings with officials and elected representatives, presentations at conferences, tradeshows, and through targeted strategies carried out in partnership with associations of `municipalities, industry organizations, and not-for-profit organizations.

Woodward Water Wash Plant Photo

List of Definitions

Anaerobic Digestion

Conversion of biomass feedstocks to biogas through the action of microbial digestion of the biomass in the absence of air.

Biogas

An unpurified gas produced during the process of microbial digestion, typically consisting of 50-60 per cent methane.

Biomethane

Purified biogas, which meets industry standards that can be burned in existing equipment. Biomethane and Renewable Natural Gas are used interchangeably.

LCNG

Liquefied-compressed natural gas (LCNG) vehicle fuelling stations which combine LNG and CNG in one station.

Methanation

A chemical process to generate methane from syngas.

RNG

Renewable Natural Gas is another word for biomethane. The term ‘renewable’ refers to the recycling of carbon already present in the atmosphere, which makes RNG a carbon neutral energy source. RNG has identical performance compared to pipeline natural gas.

Syngas

Produced during the process of gasification. Syngas is converted to methane through the process of methanation.

Wheeling

Movement of gas from a producer to a customer using shared infrastructure. Because RNG is a “drop-in” substitute for natural gas, trade transactions of RNG from a producer to a customer through the natural gas pipeline infrastructure can be created.

INTEGRATED COMMUNITY ENERGY SYSTEM BUSINESS CASE STUDY

RENEWABLE NATURAL GAS THE ONTARIO OPPORTUNITY

JULY, 2012

QUEST BUSINESS CASE

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Photo credit: AgriEnergy Producers' Association of Ontario (APAO)

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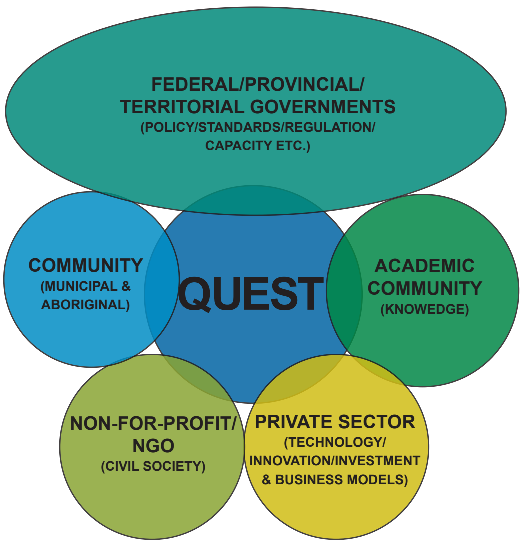
LIST OF ACRONYMS

BAU	Business as Usual
BCUC	British Columbia Utilities Commission
CES	Community Energy System
CHP	Combined Heat and Power Facility
CITP	Centre in the Park
GHG	Greenhouse Gas
DE	District Energy
Enbridge	Enbridge Gas Distribution
FIT	Feed-in Tariff
GEA	Green Energy and Green Economy Act
GHG	Greenhouse Gas
GWP	Global Warming Potential
ICES	Integrated Community Energy System
IPP	Independent Power Producer
kWh	Kilowatt hour
LDC	Large Distribution Company
LEED	Leadership in Energy and Environmental Design
kWh	Kilowatt hour
MW	Megawatt
OEB	Ontario Energy Board
OPA	Ontario Power Authority
OPG	Ontario Power Generation
RESOP	Renewable Energy Standard Offer Program
RFEOI	Request for Expressions of Interest
RNG	Renewable Natural Gas
ROE	Return on Equity
ROI	Return on Investment
SCCES	Strathcona County Community Energy System
UGL	Union Gas Limited

1. PREAMBLE

1.1. QUEST (QUALITY URBAN ENERGY SYSTEMS OF TOMORROW)

QUEST - Quality Urban Energy Systems of Tomorrow – is a national non-profit organization advancing education and research for integrated energy systems (linking energy with land-use, buildings, transportation, waste, water and wastewater at a community, neighbourhood or site level) to develop and support sustainable communities in Canada. QUEST does research, policy analysis, outreach, and capacity building to assist communities, utilities, and the broader community-building sector.



WHO MAKES UP QUEST CANADA?

QUEST Canada is a collaborative network of organizations - from energy, technology and infrastructure industries, gas and electric utilities, all levels of government, civil society groups and community leaders, researchers and the consulting community - actively working to make Canada a world leader in the design, development and application of integrated energy solutions.

QUEST'S MISSION:
Mobilize community builders to create integrated energy solutions that are central to sustainable community development.

QUEST'S VISION:
By 2030 every community in Canada is operating as an integrated energy system, and accordingly, all community development and redevelopment incorporates an integrated energy system.

QUEST is achieving its mission and vision by working with community builders to:

- Encourage a balanced and informative conversation about energy;
- Support the development of expertise and capacity across Canada for integrated energy systems;
- Prepare inclusive and independent applied research for the broader public interest; and,
- Create a collaborative framework for communities and key stakeholders to understand and to work on their energy futures.

1.2. INTEGRATED COMMUNITY ENERGY SYSTEMS

Integrated Community Energy Systems (ICES) capitalize on cross-cutting opportunities and synergies available at the community level by integrating physical components from multiple sectors:

- Land use and community form;
- Energy supply and distribution;
- Water, waste management and other local community services;
- Transportation;
- Housing and buildings;
- Industry.

ICES describe projects that are driven by local issues and community stakeholders and are integrative in nature.

The integration is threefold – first, integration among the various energy sources and technologies, energy users, distributers and producers within a community; second, integration of energy as it relates to other community services, including water, waste, transportation, land use, buildings, and third; integration of energy policy considerations, as these cut across municipal/provincial/federal mandates and priorities.

1.3. BUSINESS CASE STUDY SERIES

While considerable momentum exists in Canadian communities for developing community energy plans and planning for ICES projects, there remains limited Canadian documentation about completed ICES accomplishments. QUEST is working to break-down knowledge barriers and address this important information gap for researchers, developers, investors, and public and private sector decision makers.

QUEST has engaged five of Canada's top business schools to produce QUEST's first Business Case Series featuring ICES initiatives in British Columbia, Alberta, Ontario, Québec and Nova Scotia. The Business Case Series is designed to bring forward the key factors contributing to successful ICES project implementation.

Each ICES business case describes the project, outlining key factors related to governance, financial, technical and economic aspects of project planning and implementation. Taken together, the series provides:

- A vehicle for communicating the ICES concept to the business community and potential supporters of QUEST's work;
- An educational resource advancing knowledge of the financial aspects of ICES project planning and development;
- A foundation for further business-related ICES research; and
- A capacity-development and training tool for developers, municipalities, energy players, other project proponents and the investment community.

2. EXECUTIVE SUMMARY

This business case study examines the potential growth of an innovative energy source, renewable natural gas (RNG). The study documents the application process for two of Ontario's largest natural gas utilities to the Ontario Energy Board in late 2011 to advance RNG as a new supply source under a regulated investment model. This case study undertakes to define RNG, identifies its key attributes, highlights its use in jurisdictions outside Ontario, and provides an in-depth analysis of its current and potential application within Ontario. The case study demonstrates that the creation of an RNG industry in Ontario could bring significant benefits to the province and contribute to meeting the government of Ontario's greenhouse gas, energy efficiency and clean air targets.

RNG represents an advanced approach to using organic materials, using established technologies to produce an environmentally responsible alternative to natural gas, delivering significantly lower emissions when substituting for conventional natural gas.

RNG can be produced from a variety of local community sources, including agricultural waste, municipal organic waste landfill gas, forestry waste and other forms of biomass. RNG can be used interchangeably with natural gas in combustion equipment for heating, electricity generation and as an alternative fuel for vehicles. In Ontario, potential access to RNG is plentiful, with 32 large landfill sites, 1.7 million head of cattle, 4.5 million head of hog, and other large potential agricultural and forestry waste sources. While the supply potential is clearly there, the use of RNG is currently not being harnessed in Ontario.

The case study reviews how the emergence of a RNG industry in Ontario can benefit from decisions to encourage the market establishment of a "home grown" Ontario fuel source. Early government support has been critical in advancing new forms of energy that can contribute to advancing job creation and local economic development. In Ontario, the advancement of renewable electricity was moved forward with the passing of the Green Energy and Green Economy Act (GEA) in 2009. The GEA was focused on establishing Ontario as a leader in the reduction of greenhouse gases from electricity generation, the advancement of energy efficiency in construction, and the establishment of a renewable energy market and associated manufacturing and services.

An area not targeted by the GEA was thermal energy – in Ontario, one of the largest uses of energy in the province is for space heating and domestic hot water and other industrial processing applications[1]. This case advances RNG as a way of addressing some of the outstanding challenges Ontario faces in meeting its ambitious greenhouse gas, energy efficiency and clean air targets. The case study highlights how Canadian RNG initiatives, such as in British Columbia, are using RNG to meet alternative energy and greenhouse gas reduction objectives.

The case study outlines how fuel sources, such as RNG, can directly contribute to supporting Integrated Community Energy Systems and Solutions (ICES). For instance, local district energy systems could substitute natural gas with RNG. As well, by making use of local renewable sources of energy, energy systems become more reliable and effective through diversification and proximity to fuel sources. Similarly, RNG could displace solid biomass fuel sources that require long-distance hauling. The capacity for RNG as a community economic development opportunity is also reviewed. As a result of the fuel source opportunity being in nearly every community in Ontario, both public and private interests could choose to be active in supplying sources of RNG.

The applications by Union Gas Limited and Enbridge Gas Distribution to facilitate the emergence of a RNG industry in Ontario are noteworthy for the fuel source and economic development potential of RNG. At this early stage of RNG development in Ontario, the application by the gas utilities highlights their interest in working to be community energy systems builders. Their applications makes clear that leadership from both the private

1 Environmental Commissioner of Ontario. (2010). Annual Energy Conservation Progress Report – 2009. Vol 1.

and public sectors will be required to establish RNG as a mainstream fuel for thermal and electricity generation applications. The application process for RNG suggests that without support from the province of Ontario and local municipalities, it is likely that the potential economic and environmental benefits of RNG will not be realized in the immediate interim for the province of Ontario.

3. RENEWABLE NATURAL GAS: WHAT IS IT?

Renewable natural gas (RNG) is a renewable and carbon neutral energy source.[2] It is also referred to as biomethane. When used in place of natural gas, RNG results in the reduction of greenhouse gas (GHG) emissions. The production of RNG is distinct yet related to other bioenergy sources. It can, but does not necessarily, rely on the same feedstock as traditional energy production from biomass, such as agricultural waste, forestry waste, and crop residue. Similarly, it requires an intermediary process of producing either raw biogas via anaerobic digestion systems or syngas via gasification. However, RNG production is far more efficient than these traditional approaches yet it requires further refinements to the raw biogas or syngas in an upgrading system to allow for it to be injected into the existing natural gas pipeline network. Well-established technology exists to upgrade the biogas or syngas to RNG. This ensures that this renewable energy source acts as a reliable and safe complement to traditional natural gas.

3.1 A BIO-BASED ALTERNATIVE TO NATURAL GAS

RNG represents an advanced approach to using biomass and established technologies for the production of an environmentally responsive alternative to natural gas. Despite dating back well into history, the use of biomass for energy production remains a significant element of the Canadian energy mix. It supplies about 4.7% of primary energy demand, the second largest source of renewable energy after hydroelectricity. The pulp and paper industry is by far the largest user of biomass and has approximately 1,700 megawatts (MW) of installed electrical capacity and burns bark, wood chips, sawdust, and black liquor (by-product of the pulp production process) to produce heat and power. Beyond the forest products industry, several independent power producers (IPPs) generate power from the combustion of wood wastes and other biomass material. There are approximately 20 of these plants with an installed capacity of 378.1 MW.[3]

There are several district energy (DE) systems in Canadian communities that provide heat and power via biomass combustion. Communities, such as Grande Prairie, Alberta, have invested in new DE systems fuelled by wood waste from nearby sawmills. In Atlantic Canada, existing DE systems have been modified to burn wood wastes; thereby lowering the region's reliance on hydrocarbons. These systems use wood pellets, the production of which has grown four fold in Canada, from 500,000 tonnes in 2002 to 2,000,000 tonnes in 2008. Canada also has a large and burgeoning fuel ethanol industry that produces approximately 238 million litres of ethanol each year, mainly from food crops, such as corn (65 per cent) and wheat (35 per cent). Currently, ethanol is used as an additive, mixed with gasoline in blends containing up to 10 per cent ethanol. Canada also annually produces nearly 100 million litres of biodiesel.[4] It is important to note that as a result of federal mandates requiring 5% ethanol in gasoline and 2% renewable diesel in diesel fuels sold at the pump, biomass-based fuels have benefited from significant financial and policy support.[5]

Despite a long history of biomass use for energy production, Canada has only begun to embrace RNG as an environmentally responsible, biomass-based alternative to natural gas. This very recent shift in attention is

2 Terasen Gas Inc. (2010). Biomethane Application.

3 Canadian Centre for Energy Information. (2011). Biomass Energy in Canada. Retrieved at http://www.centreforenergy.com/AboutEnergy/Biomass/Overview.asp?page=6

4 Canadian Centre for Energy Information. (2011). Biomass Energy in Canada. Retrieved at http://www.centreforenergy.com/AboutEnergy/Biomass/Overview.asp?page=6

5 *Canadian Environmental Protection Act*, 1999. Subsection 332(1).

in part due to increasing demand for natural gas as an energy source. In Canada, demand for natural gas has grown 40% from 1990 to 2008.[6] Export demand has grown even more rapidly, increasing 155% over the same period.

Increased demand has been driven by a number of factors, including: higher oil prices, expansion of natural gas production and distribution networks, improved greenhouse gas and air pollutant emissions profile for natural gas combustion relative to coal and petroleum fuels and the increased demand for natural gas as a fuel for peaking and intermediate electricity generation to complement intermittent sources such as wind turbines and solar panel generation. The growing demand for natural gas has helped to make RNG particularly attractive since it can be blended with the traditional product and used in the same pipeline infrastructure with no difference for end use consumers.

While the end use of RNG is indistinguishable from natural gas, the fundamental differences between them are its source and chemical composition in their raw forms. Natural Gas is extracted from below the Earth's surface. As a result, upon combustion it releases GHGs that would otherwise be kept underground. While its composition can vary, the natural gas used in Ontario is comprised mainly of methane (>95%), with other elements, including ethane, propane, and nitrogen. Many of these trace elements are removed from the extracted natural gas before being injected into the pipeline as a commercial grade product. On the other hand, RNG is sourced from waste products that without treatment (such as the flaring of biogas at municipal landfills) or conversion (such as anaerobic digestion of agricultural waste) would naturally release methane into the atmosphere. Studies have shown the disproportionate impact of methane as a GHG by putting it at 21times the greenhouse gas warming potential than that of carbon dioxide (CO_2).[7] Thus, processing the waste into RNG provides an effective means to reducing these harmful emissions. In its pre-processed form as biogas, it can be composed of about 40% to 60% methane, 40% to 50% CO_2, and various other chemicals depending on the waste used as the feedstock. Following the upgrade of the biogas, RNG has a composition virtually identical to conventional natural gas with methane content of over 95%. As a result, RNG can be used interchangeably with natural gas in combustion equipment, including furnaces, boilers and engines.

3.2 PRODUCTION OF REWABLE NATURAL GAS

Unlike other forms of renewable energy (i.e. solar or wind) the production and use of RNG, in many cases, requires less capital investment or change in consumer behaviour. The production process leverages existing knowledge and infrastructure.

3.2.1 SOURCING RAW BIOGAS

The first step of the production process involves sourcing raw biogas that is comprised primarily of methane (CH_4) and carbon dioxide (CO_2) with much smaller amounts of contaminants such as hydrogen sulphide (H_2S) and ammonia (NH_3). Trace amounts of hydrogen (H_2), nitrogen (N_2) and oxygen (O_2) are also occasionally present in biogas. Usually, the gas is saturated with water vapour and may contain other particles andorganic silicon compounds (siloxanes). This biogas can be combusted as is done at many municipal landfills; however, due to its lower methane content, raw biogas has a lower energy density than natural gas (or RNG) and therefore produces less heat when combusted than an equivalent volume of natural gas. Table 3.1 illustrates the differences between raw biogas and RNG.

6 ICF International. (2010). 2010 Natural Gas Market Review.

7 Intergovernmental Panel on Climate Change. (2007) Retrieved at http://www.ipcc.ch/publications_and_data/publications_and_data_reports.shtml.

Compound	Raw Biogas	Renewable Natural Gas
Methane (CH_4)	40-64%	95%+
Carbon Dioxide (CO_2)	40-50%	<2%
Oxygen (O_2)	0-2%	<0.4%
Hydrogen Sulphide (H_2S)	0-2000+ ppm	0 ppm
Water (H_2O)	Saturated	<0.65 mg/m^3
PCBs	Varies on feedstock	<0.1ppb
Pharmaceuticals	Varies on feedstock	<1ppb
Pesticides	Varies on feedstock	<1ppb

TABLE 3.1: Comparison of Biogas and Renewable Natural Gas[8]

The primary feedstock that could supply raw biogas includes processed agricultural and organic waste, forestry waste, crop residue, municipal organic waste, landfill gas and sewage waste. Costs can vary significantly by feedstock and include sourcing, transporting, and processing the waste material. However, Ontario is well positioned for almost all feedstock options due to its large urban populations and mature farming and forestry bases which are connected by pipeline infrastructures.

Biogas can be produced either via biological or thermochemical processes, depending on the moisture content of the feedstock and temperature of the production process. Whereas the biological process uses anaerobic digesters, the thermochemical process involves gasification. The costs involved with either of these approaches can vary considerably depending on feedstock and size of operation, but this part of the process represents the most costly capital investment in the production of RNG.

Anaerobic Digestion is a series of processes where microorganisms break down biodegradable material in the absence of oxygen at relatively low temperatures of 30°C to 55°C.[9] It is already used in many municipal wastewater treatment systems to reduce the volume of solid waste and produce raw biogas used on-site or flared. It is also commonly used for managing animal waste on farms. Almost any biodegradable organic material can be processed through anaerobic digestion. This includes biodegradable waste materials such as waste paper, grass clippings, food processing waste or spoilage, sewage and animal waste.

After sorting or screening to remove physical contaminants, such as metals and plastics, from the feedstock, the material is often shredded, ground, or hydrocrushed to increase the surface area available to microbes in the digesters and hence increase the speed of digestion. The material is then fed into a digester vessel where the anaerobic processes take place. The treatment involves four processes: (1) hydrolysis, (2) acidogenesis, (3) acetogenesis, and (4) methanogenesis.

The biogas produced at landfills follows the same process as anaerobic digestion, but it occurs without human intervention. In this case, biodegradable waste (e.g., organic wastes) breaks down naturally and produce methane gas (commonly referred to as landfill gas) that when not captured and treated represents a significant source of GHG emissions. An important challenge presented by landfill gas in RNG production is that it often varies in chemical composition and involves removing other contaminants. Furthermore, the process is only economically viable for large-scale landfill operations. For example, concerns with chlorine and PCB compounds has led California to prohibit injection of landfill gas. Interestingly, the Ontario Government mandated in 2008 that all large, active landfills in the province must collect landfill gas and either flare it or use it in some other manner. This legislation makes landfill gas a more attractive source of biogas for RNG.[10]

8 Terasen Gas Inc. 2010.
9 U.S. Department of Energy (2011). How Anaerobic Digestion Works. Retrieved at http://www.energysavers.gov/your_workplace/farms_ranches/index.cfm/mytopic=30003
10 Ontario Regulation 217/08.

II. *Gasification* is a thermochemical process that has drawn recent attention for its ability to produce electricity from coal at a cleaner rate than traditional coal combustion in power plants. However, almost any type of organic material can be used as the raw material for gasification, including wood, other biomass sources and even plastic waste.[11] Gasification relies on chemical processes at elevated temperatures of between 700°C to 1800°C, which distinguishes it from anaerobic digestion. The process converts carbonaceous materials, such as biomass, into carbon monoxide, hydrogen and methane by reacting feedstock at elevated temperatures with controlled amounts of oxygen.

Gasification does not involve combustion but instead uses intense pressure combined with oxygen or air to convert carbon-based materials directly into gas. The gasification process breaks these materials down to the molecular level, so impurities can be relatively easily and inexpensively removed. The resulting gas mixture is called synthesis gas or syngas and is itself, a fuel. Syngas may be burned directly but with a chemical composition of only 3% methane it has a much lower energy density relative to natural gas. As a result, conversion to RNG would also require further refinement through catalytic methanation. While often more efficient than anaerobic digestion processes, gasification is not currently economic or practical for most RNG projects due to the current state of the technology and its high up-front investment costs.[12]

The Alberta Research Council has projected the potential methane production from each major waste feedstock across Canada.[13] In this study, Ontario is favourably positioned with regard to each type of feedstock and it ranks third nationally with regard to the availability of resources necessary to embrace RNG. As is depicted in Figure 3.1, gasification presents a more effective process for sourcing biogas, yet it is envisioned that anaerobic digestion will be the main method used to produce biogas for RNG source over the next decade with gasification contributing afterwards. This projection is based on the availability of the technologies, prior use and acceptance by industry.

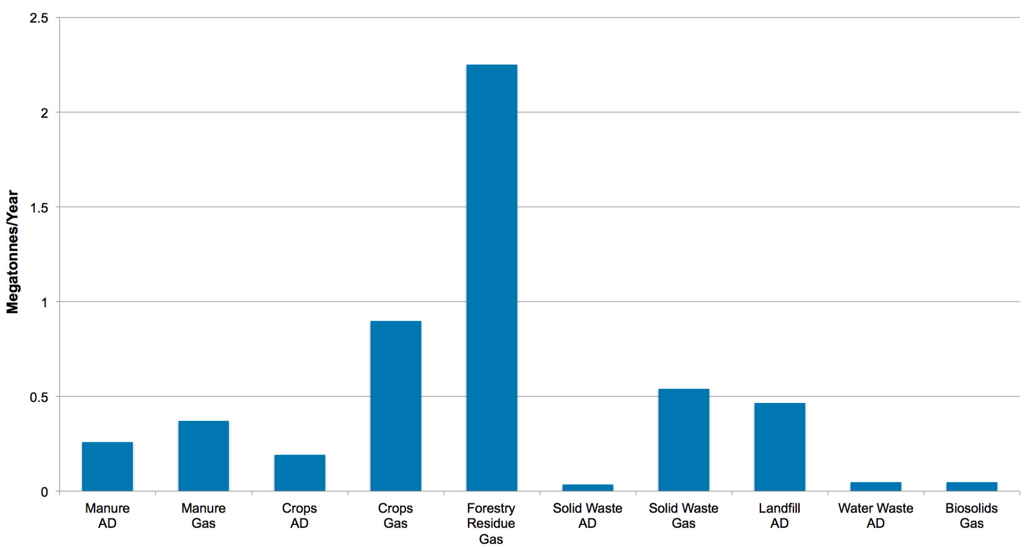


FIGURE 3.1: Potential Methane Production from Waste (megatonnes/year)[14]

11 Gasification Technologies Council. (2011). Gasification Facts. Retrieved at http://www.gasification.org/page_1.asp?a=85.
12 Alberta Innovates-Technology Futures. (2010). Potential Production of Methane from Canadian Wastes. Retrieved at http://www.cga.ca/pdfs/RNGpotential.pdf
13 Alberta Innovates-Technology Futures. (2010). Potential Production of Methane from Canadian Wastes. Retrieved at http://www.cga.ca/pdfs/RNGpotential.pdf
14 Alberta Innovates-Technology Futures. (2010). Note: Potential was based on the most appropriate technology for biogas production; where AD corresponds to anaerobic digestion and Gas to gasification.

3.2.2 UPGRADING BIOGAS TO RNG

In order for its injection into the existing natural gas distribution network, it is essential to remove unwanted elements from biogas or syngas to produce RNG, effectively making it indistinguishable from conventional natural gas. The primary processing is the removal of non-combustible gases, which in turn increases the heating value of the gas. Elements such as N_2, O_2 and H_2 are removed and monitored to ensure that they are only present in such small amounts so that they do not impact the safety or the heating value of the gas. Other contaminants such as H_2S, NH_3, siloxanes, water vapour and other materials are filtered out to ensure that the end product is clean and safe for pipeline injection. In order to upgrade the biogas to natural gas quality, multi-stage cleaning and upgrading treatment are needed to obtain desired RNG and remove unwanted CO_2. The cleaning and upgrading processes depend on the feedstock, biogas production process (anaerobic digestion or gasification). Without this cleaning/upgrading, contaminants in the raw biogas would result in equipment issues such as corrosion or fouling of burners and may also cause hazardous exhaust products. The capital expenditure of the upgrading process is significantly less than that required for biogas production.[15] For instance, the capital costs for an average farm that chooses to produce RNG would be about $4.5 million, only $1.6 million of which would be allocated to the upgrading equipment.[16]

The higher the methane content, the better the RNG will match natural gas and can be interchangeable in a common pipeline. Interchangeability is the objective and the upgrading process must ensure that the RNG has the appropriate (i) heat content, (ii) Wobbe index[17], and (iii) chemical composition. Once deemed interchangeable, RNG could be blended with natural gas, transmitted and distributed through the pipeline network with no discernible difference to retail customers. In Ontario, the potential to harness local feedstock to supply RNG production has been forecasted to potentially displace 18% of current residential, commercial, and industrial natural gas demand.[18]

15 In 2010, the Canadian Gas Association and its member companies formed the Biomethane Task Force that consulted and established an industry accepted guideline for RNG composition that would be accepted in Canadian gas pipelines. While the guideline is not a standard or requirement, it is being used as the basis for work in Quebec to establish a standard for biomethane pipeline quality. More information is available through the Canadian Gas Association at www.cga.ca.

16 Electrigaz . (2011). Biogas Plant Costing Report.

17 The Wobbe index of a fuel gas is found by dividing the high heating value of the gas in Btu per standard cubic foot by the square root of its specific gravity with respect to air. The higher a gases' Wobbe number, the greater the heating value of the quantity of gas that will flow though a hole of a given size in a given amount of time.

18 Alberta Innovates-Technology Futures. (2010). Potential Production of Methane from Canadian Wastes. Retrieved at http://www.cga.ca/pdfs/RNGpotential.pdf

4. WHY DO WE CARE ABOUT RENEWABLE NATURAL GAS?

The value proposition created by injectable RNG is based on its potential to create significant environmental benefits that uses existing natural gas pipeline infrastructure and available technology without requiring any change to consumer behaviour. Furthermore, it takes a more responsible approach to managing waste that leverages the local supply of renewable resources and can create economic development opportunities for communities.

4.1 ENVIRONMENTAL BENEFITS OF RENEWABLE NATURAL GAS

The primary environmental benefits of RNG come from (1) emission reductions and (2) fuel substitution. The potential reduction of 18.9 Mt CO_2 per year or about 9.5% of Ontario's total GHG emissions in 2010 is significant.[19] The ability for producers or utilities to monetize these GHG reductions in the form of carbon credit could help subsidize the premium cost in producing RNG and possibly provide an additional stream of revenue. In sum, the environmental benefits of injectable RNG supports three of QUEST's technical principles since it reduces waste, uses renewable resources, and uses the energy grid strategically in these efforts.[20]

4.1.1 EMISSION REDUCTION

Emission reductions are achieved through the capture of methane emitted from landfills and farm and animal waste. Left untreated organic material would typically decompose and release methane directly into the atmosphere. Methane has a global warming potential (GWP) of 21 while carbon dioxide's GWP is 1, which means that each molecule of methane has 21 times the impact on climate change as one molecule of carbon dioxide. This makes methane one of the major contributors to anthropogenic global warming.

Utilizing RNG, similar to the combustion of biomass or raw biogas, for heating and other purposes does create carbon dioxide (CO_2) but prevents methane from directly entering the atmosphere, which reduces overall greenhouse gas emissions. Since the feedstock for RNG is organic material then the release of CO_2 is actually going to support its own regeneration in the form of new biomass. Therefore, the process truly supports renewable resources. As a result, RNG has been deemed to be carbon neutral since both combustion and lifecycle emissions do not contribute any net greenhouse gases into the atmosphere. This 'closed-loop' process is depicted in Figure 4.2. Additional benefits of this process is that injectable RNG is able to use the current natural gas pipeline system, so that the energy grid is used strategically and additional resources are not needed for distribution to customers. Also, the feedstock processing and upgrading steps are mostly co-located and are close to the pipeline so costly and environmentally intensive on-land transportation can be avoided.

19 Alberta Innovates-Technology Futures. (2010). Potential Production of Methane from Canadian Wastes. Retrieved at http://www.cga.ca/pdfs/RNGpotential.pdf

20 The QUEST principles are the foundation of Quality Urban Energy Systems of Tomorrow (QUEST), which is an initiative focused on promoting an integrated approach to land-use, energy, transport, water and waste management in communities and urban centres, in order to address energy end-use and reduce greenhouse gases (GHGs).

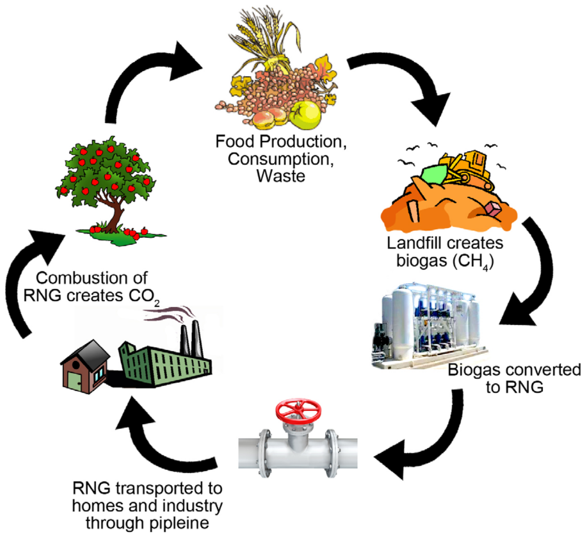


FIGURE 4.2: Closed Loop Carbon Cycle

4.1.2 FUEL SUBSTITUTION

Fuel substitution is equally important and applies when RNG can be used instead of or as a partial substitute to natural gas to reduce GHG emissions. This would be similar to using solar or wind generated electricity as a substitute for coal generated electricity. But in this case the gas sold to customers would likely be a blend of natural gas and RNG, which would be completely indiscernible to end use customers. The use of RNG would displace a carbon positive energy source in the form of natural gas with a renewable, carbon neutral energy source. The use of RNG as a substitute may prove to alleviate some of these concerns, as customers would be able to support a renewable alternative that is less environmentally sensitive. If a functioning market for RNG could be established it would promote natural gas supply source diversity and support the local community where the RNG is produced. In the case of Canada as a whole, fuel substitution represents the greatest reduction potential in GHGs (see figure 4.3).

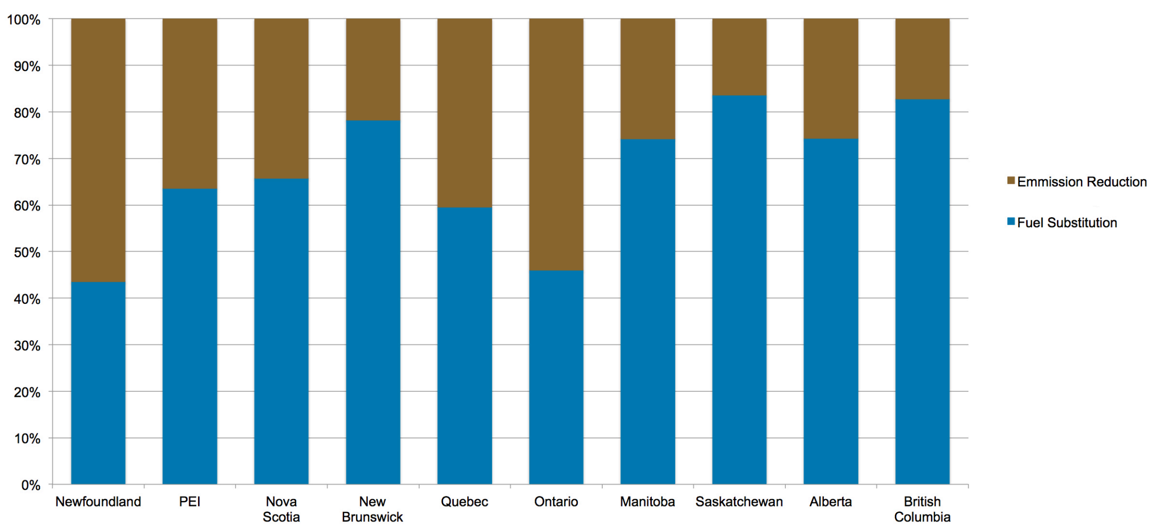


FIGURE 4.3: Source of GHG Emissions Reductions (% of total)[21]

21 Alberta Innovates-Technology Futures. 2010.

4.2 EFFICIENCY GAINS OF RENEWABLE NATURAL GAS

While there is no market for RNG in Ontario today, biogas is usually used in the production of electricity as part of the Green Energy Act's Feed-in-Tariff (FIT) program. Several landfills, municipal waste treatment plants and farming operations have used raw biogas to generate their own electricity and feed it into the transmission grid. While these projects earn a premium (see Table 4.1) from the Ontario Power Authority (OPA) and may be preferred to other electricity generating sources, it is not the most efficient use of this energy. Rather, upgrading biogas to RNG for direct consumption can be between two and three times more efficient than converting raw biogas into electrical energy in a traditional electricity-only generating process.[22]

Generating Technology Type	Price per Kilowatt hour (kWh)
On-Farm Biogas System - Less than 100 kW	19.5¢
On-Farm Biogas System - From 100 kW to 250 kW	18.5¢
All other Biogas System - Less than 500 kW	16.0¢
All other Biogas System - 500 kW to 10 MW	14.7¢
All other Biogas System - Greater than 10 MW	10.4¢

TABLE 4.1: Ontario FIT prices for Biogas[23]

Figure 4.4 illustrates how the same energy source used in two different applications can lead to very different results. First, the raw biogas has to be processed into a transportable form. The conversion process in an upgrader from biogas to RNG is about 90% efficient, while converting to electricity using a reciprocating engine with no heat recovery the efficiency is closer to 35% efficient. The transmission losses are approximately 3% for gas and 6% for electricity. In its end use, homes are able to take advantage of all of the electrical energy, whereas gas losses are typically less than 8% for a high efficiency furnace. Considering both the relative efficiencies of the conversion processes and end use, RNG is over two times more efficient when compared to the use of raw biogas in an electricity-only generation process.

22 If raw biogas was combusted in a combined heat and power (CHP) system it could be just as efficient since waste heat is efficiently used as part of the process.

23 Ontario Power Authority. 2010.

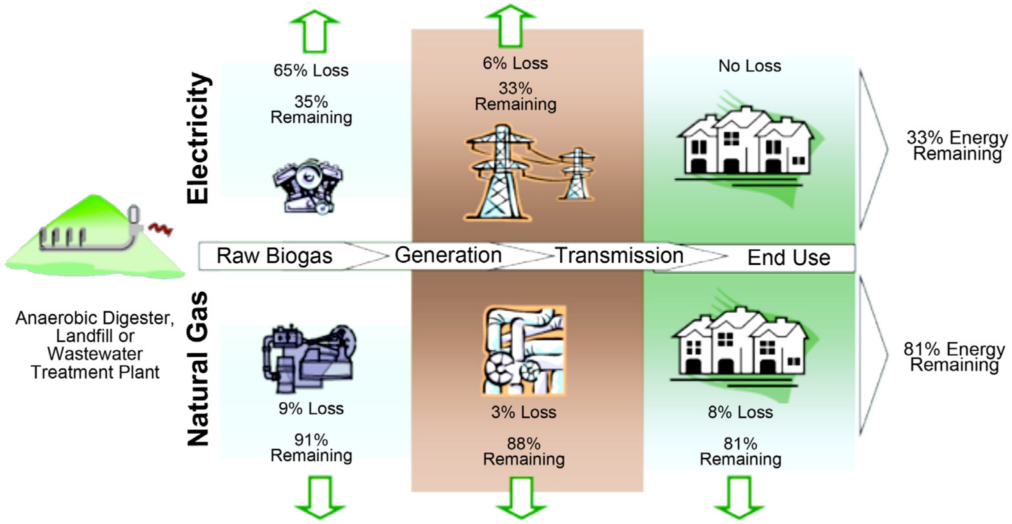


FIGURE 4.4: Efficiency of RNG Production[24]

4.3 ECONOMIC DEVELOPMENT BENEFITS FROM RENEWABLE NATURAL GAS

While the environmental and efficiency gains of RNG are considerable, the benefits that could come to those supplying the feedstock and raw biogas are substantial. The communities that would benefit from a functioning market for RNG are wide ranging and include both urban and rural interests. Ontario is well positioned to supply the industry with 32 large landfill sites, 1.7 million head of cattle, 4.5 million head of hog, and significant agricultural and forestry waste. As a result, the economic benefits may be widely distributed as both public and private interests could choose to be active in supplying the market with raw biogas for RNG production. Preliminary estimates suggest RNG produced from Ontario waste could supply about 18% of the total NG sold by province's utilities.[25]

24 Terasen Gas Inc. 2010.

25 Alberta Innovates-Technology Futures. (2010). Potential Production of Methane from Canadian Wastes. Retrieved at http://www.cga.ca/pdfs/RNGpotential.pdf.

5. BUSINESS OPPORTUNITIES FOR UTILITIES IN RENEWABLE NATURAL

The business models for injecting RNG into the pipeline network are still being established; utility firms in various jurisdictions have adopted a variety of approaches to benefit from the technology. Nonetheless, it is still relatively early in the RNG industry's development and no optimal approach has yet been established. Plans to harness this form of energy have placed varying degrees of emphasis on managing the supply side, the demand side, or both. Regulatory authorities have not considered RNG relative to their involvement in renewable electricity, which has been a contributing factor in the void in the RNG marketplace.

5.1 CANADIAN INITIATIVES

Given the significant biomass resources available in Canada, the use of biogas has been used for on-site electricity generation at forestry operations or livestock farms and processing at active landfills. However, upgrading to RNG has significantly lagged behind developments in both Europe and the US. In 2010, FortisBC (then doing business as Terasen Gas Limited) in British Columbia took a significant step to develop a market for RNG and make it available to their customers. This move marks the first effort to commercialize RNG in Canada.

In the summer of 2010, FortisBC filed an application with the BC Utility Commission (BCUC) to introduce an "End-to-end business model for the acquisition of Biomethane supply and the sale of a renewable energy, or 'Green Gas' offering to FortisBC Gas customers."[26] FortisBC would be solely responsible for the relationship between the customer and the delivery of the product that they consume. However, its business model would be quite different from that taken by utilities in both Europe and the US. Instead of simply seeking a price or preferential treatment for injecting RNG into the pipeline, it sought approval for a model that would not only include investments in the upgrading and injection of RNG but also the marketing of it to the end-consumer as a premium product that would come with an additional cost.

According to their application, their model had three distinct steps:

1. Acquiring supply of RNG where partners are responsible for all collection of raw material and the facilities to produce biogas; FortisBC would be responsible for upgrading and interconnection, which would allow them to ensure the quality of the product and its interchangeability with natural gas. This stage was seen as providing flexibility in controlling and developing the supply side of the market. Furthermore, FortisBC was clear that they were not interested in owning the biogas production assets, which gets them away from the greatest capital expenditures necessary for the injection of RNG into their pipeline.
2. Selling RNG to residential and commercial customers who are interested in a cleaner alternative to natural gas. This stage of the business model would be rolled out over two phases with the first involving a 10% blend of RNG for residential customers beginning in October 2010 and the second a 10% blend of RNG for commercial customers beginning in January 2012. This stage was seen as meeting pent up interest on the demand side of the market that could be met in a matter of months. As a result, they saw themselves as ensuring "demand is met safely, reliably, and economically."
3. Allocating and recovering the costs of the project. FortisBC saw "Green Gas" as a premium product that customer would be willing to pay extra for. Similar initiatives in the US where utilities market electricity from renewable sources as a premium product that some customers choose to pay more for. Customers that opted into the program would bear all the costs for the energy that they choose to consume, while all of FortisBC's customers would bear the costs for making the project available (ie. costs associated with marketing, regulatory, administration).

Driving FortisBC's choice of an "end-to-end" business model were a series of factors, including government

26 Terasen Gas Inc. (2010). Biomethane Application

support for environmental issues, the supply of raw biogas and partners in the province, and strong customer demand for environmentally-responsive alternatives.

Government Support for environmental issues. FortisBC relied heavily on the province's Clean Energy Act (CEA) as motivation for the "Green Gas" project. Although the CEA had not specifically mentioned RNG, it had laid out a "Bioenergy Strategy" that offered general attention to projects that utilize energy from wood waste, agriculture, renewable fuels and municipal waste. Figure 5.2 derived from the application and highlights the attention to detail that the firm placed in linking their proposal to the CEA in their effort to convince the regulator to approve the effort.

Substantial supply of raw biogas and partners. Since FortisBC had no interest in controlling the supply of raw biogas nor making substantial investment in processing assets (ie. anaerobic digesters, landfill gas capture equipment), it was essential that there was not only a significant feedstock supply but also partners that would be willing to take on considerable risk in supplying the processed feedstock. In 2009, prior to making the application to the BCUC, FortisBC issued a "Request for Expressions of Interests" (RFEOI) and received 9 proposals in response. They continued to receive interest and by the time the application was filed, management claimed that there were likely 20 partner projects that would fit what they were seeking for the "Green Gas" program. Based on their projections they expected they would likely be able to have about 1.9 and 4.8 Petajoules (PJ) of RNG online by 2020.

As part of the application, FortisBC had identified two partnerships that would form their initial supply of RNG for the "Green Gas" program. The first was with the Columbia Shuswap Regional District (CSRD) who operated a landfill in Salmon Arm, BC. In this partnership, FortisBC would invest in biogas upgrading equipment along with the distribution main and interconnection facilities, which includes gas quality monitoring, pressure regulation and odorizing. Their proposed investment would total approximately $2.3 million and CSRD would invest $4.8 million to install the landfill gas capture, collection and flare system. This project would provide annual delivery of approximately 30,000 GJ or about enough RNG to serve 300 households.

The displacement of natural gas with RNG would reduce GHG emissions by approximately 1,500 tonnes. The second project was with Catalyst Power Incorporated (CPI), which would invest in an anaerobic digestion system for processing organic agricultural waste in Abbotsford, BC. This partnership was slightly different in that FortisBC would not be investing in the upgrader but rather only in facilities required to measure the flow of gas and to ensure that the biogas quality meets pipeline specifications. As a result, their capital investment was only $600,000, while CPI would invest $5 million in the digestion, gas collection and upgrader technology. The injected RNG supplied would total about 84,000 GJ a year, which would displace natural gas use for about 875 households. This would lead to a reduction in GHG emissions of about 4,000 tonnes annually.

Customer demand for environmentally-responsive alternatives. In support of their application, FortisBC hired a marketing research firm to conduct a study in order to validate and evaluate the potential residential and commercial markets for a biogas program in BC, its market drivers, and factors affecting different price points. The residential survey consisted of 1,401 online surveys completed in the fall of 2009, while the commercial survey was conducted with 500 commercial customers in the winter of 2009. The findings of this report formed an important basis for its application as these findings had indicated strong support for a renewable energy-based program, in which customers can sign up for a portion of their gas use to come from the Company's proposed RNG supply projects. There was also a strong preference among survey participants for a 10% premium to the commodity price, which would result in a 10% blend of biogas. Figures 5.2 depict just some of the results that identify the overwhelming support that the surveyed FortisBC customers demonstrated for RNG.

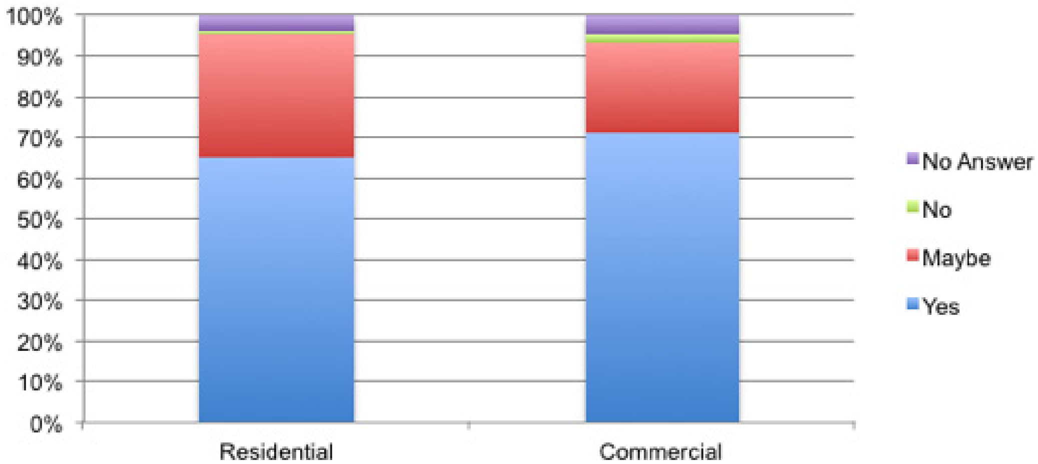


FIGURE 5.2: Should FortisBC invest in a RNG Program?[27]

In December 2010, the BCUC approved the application and provided FortisBC with an initial 2-year window to market green gas. The offering was launched to customers in June 2011; the details of its offering included a 10% RNG blend for an 11.7% premium over conventional natural gas. This works out to an extra $0.53 per GJ or approximately $4 per month for the average home in the program. Since this CSRD-led project will be late in coming online, the inventories of available RNG were lower than expected. As a result, FortisBC decided to have a more passive marketing launch. Despite this fact, by August 2011 they had already signed up 412 customers in a matter of months and remain very optimistic for the program's future growth.

27 TNS Canadian Facts. 2009.

The adoption of RNG in Ontario, Canada's largest residential natural gas market, grew out of a joint effort by the province's two largest Local Distribution Companies (LDC). With significant interest in developing alternatives to hydrocarbon-based energy sources in the direction of government policy on climate change and local economic development, Union Gas Limited (UGL) and Enbridge Gas Distribution Inc. (Enbridge) were motivated to identify projects that would help secure their firm's multi-billion dollar investment in the province. RNG presented such an opportunity as it not only was in the spirit of the province's ambitious Green Energy and Green Economy Act (GEA), but it also allowed their firms to continue to source gas locally and not stray too far from their core business strategies. Yet historically low natural gas prices and policy uncertainty in the province would present significant challenges to the firms' effort. Nevertheless, in September 2011, the firms filed a joint application with the Ontario Energy Board (OEB) requesting approval for a modest program that would help create an industry for RNG in the province.[28]

6.1 NEW INDUSTRY CREATION

As of the fall of 2011, Ontario's experience with RNG was limited. Both UGL and Enbridge had fielded requests from potential suppliers of RNG, but under the current regulatory framework it would be impossible to economically satisfy such offers. Any attempt for the LDCs to bring together the potential supply and demand for RNG would be impeded by the fact that ever since the move to deregulate the industry, the two LDCs were restricted from entering into long-term supply contracts with residential and commercial customers nor were they able to pay the requisite premium that RNG suppliers would require.

Long-term contracts would allow the suppliers to be able to make the requisite capital expenditure and realize the necessary return. The potential suppliers included farmers, municipalities, and landfill operators; all of these suppliers would need the certainty of stable cash flows to convince the financial community of the long-term viability of these investments. Even if the LDCs were able to offer long-term contracts to these suppliers, the initiative would be difficult without a premium for the RNG. Under recent market conditions with NG priced around $4/GJ, the price of conventional natural gas was around $10 less than what would be required by RNG suppliers (see Figure 6.1 for recent price trends). As a result, the current regulatory regime would make it difficult for the LDCs to enter the RNG market and supply their customers an environmentally friendly product.

28 "Renewable Natural Gas Application", Ontario Energy Board Docket Number EB-2011-0242 (Enbridge) and EB-2011-0283 (Union Gas).

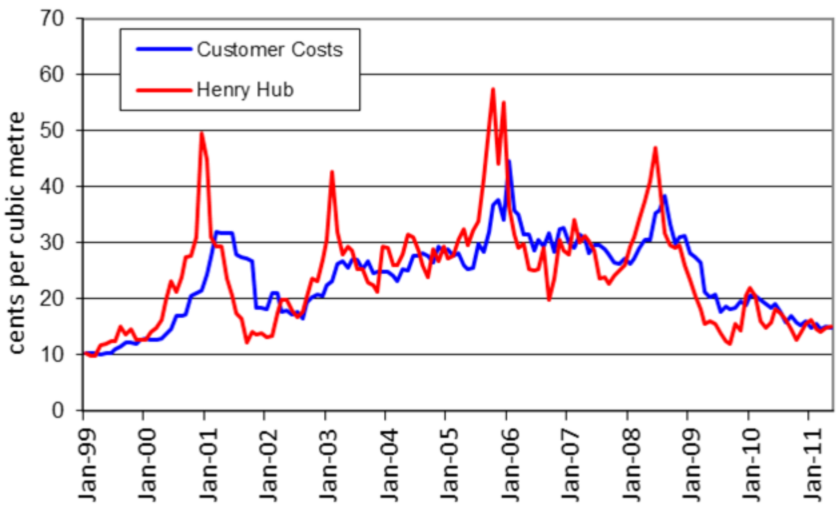


FIGURE 6.1: Monthly Average Residential Natural Gas Commodity Costs[29] and Henry Hub Prices[30] in Cdn¢/m³, Jan. 1999 – Nov. 2011

Supply of RNG in Ontario. Despite the challenges that were presented to the LDCs to supplement their current natural gas supply with a cleaner alternative, their geographical footprint in Ontario provided access to a substantial supply of the necessary feedstock. The province is well endowed with the necessary waste products to produce the biogas that could be upgraded and injected into the LDC's natural gas pipelines. The key waste sources in the province are agriculture waste (60%), forestry residue (4%), and municipal waste (36%).[31]

While anaerobic digestion processes are technically feasible for processing the feedstock , gasification is still at the laboratory phase and is considered too costly in the near-term despite its greater potential for processing larger numbers of agricultural and municipal solid wastes, not to mention forestry residue and biosolids that could not be processed using current anaerobic digestion technology. Over the short-term, 5.6% of natural gas demand in Ontario may be displaced by RNG (1,372M m^3/yr of the total 2010 distribution volume of 24,250M m^3/yr)[32]. However, over the long- term, once gasification processes become commercially viable, approximately 18% of natural gas demand may be displaced by RNG. See Table 6.1 for a breakdown of the potential for RNG in Ontario.

29 Canadian Gas Association member companies websites, accessed December 2011
30 NYMEX average monthly converted to Canadian cents via St. Louis federal reserve monthly US/CDN exchange rate
31 Alberta Innovates-Technology Futures. (2011). Potential Production of Renewable Natural Gas from Ontario Wastes.
32 Ibid.

Annual Potential RNG Production from Ontario Wastes
(Million m^3/yr)

	Agriculture Wastes				Forestry Residue	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)	
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**	**18**	**45.4**	**738**	**64**	**68.1**	**68.7**	**4435**

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

TABLE 6.1: Potential RNG by LDC in Ontario[33]

Although the supply potential in Ontario is apparent, it is not being tapped for RNG production. The only facility designed for such use was a biogas cogeneration project at a Hamilton Wastewater Treatment Plant that had received support from the Ontario Electricity Financial Corporation (OEFC).[34] This project allowed Hamilton to lower its energy consumption, increase its energy efficiency, reduce greenhouse gases and minimize the amount of natural gas required to heat the wastewater treatment plant and wastewater digesters; all of these benefits were consistent with the objectives of GHG reduction and fuel substitution. Nevertheless, like most other biogas operations in the province, it had relied on generating electricity and/or heat capture rather than upgrading to an injectable form of RNG. In fact, Ontario had over 20 biogas facilities on farms or near food processing plants and many of the province's landfills had used raw biogas to produce electricity rather than merely flaring it off. As of December 31, 2010, the Ontario Power Authority (OPA) has been managing 180 megawatts (MW) of bio-energy contracts despite their inefficiency relative to upgrading the same biogas and injecting it into the NG infrastructure.[35]

In addition to these biogas sources already being developed, the Ontario FIT program has created an incentive for significant investment into electricity production from these sources. The program has offered an attractive 10.4 to 19.5 cents per kilowatt-hour (kWh) for projects ranging from less than 10 kilowatts (kW) to projects greater than 10 MW in size. Since its formation in May 2009, 127 bioenergy applications have been submitted with only 7 having been completed and connected to the transmission/distribution grids. With an an additional investment of between $0.5 million and $3.7 million[36] in an upgrader and additional ancillary costs, similar projects would be able to produce RNG and inject it into the natural gas pipeline (See table 6.2 for a description of investments needed to upgrade biogas including the investment in an anaerobic digester, where necessary). Given the opportunity, these projects would be able to avoid the technical and often lengthy interconnection obstacles that persist in the Ontario electricity market and supply renewable energy by injecting upgraded biogas in either UGL's or Enbridge's pipeline infrastructure.

33 Alberta Innovates – Technology Futures. 2011.
34 Environment Canada. (2008). New Technologies or 'Clean' Technologies. Retrieved at http://www.ec.gc.ca/p2/default.asp?!ang=En&n=AC4DF9C1-1.
35 Ontario Power Authority. (2010). December 21, 2010 – Program Update. Retrieved at http://fit.powerauthority.on.ca/december-21-2010-program-update.
36 Electrigaz Technologies Inc. (2011). Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Distribution Grid in Ontario.

Feedstock Source	AD Process	Upgrading Process	Injection, Pipe, and Compression Process	Financing Costs	Total Capital Costs
Baseline Farm	$2,252,000	1,561,000	529,930	105,989	**$4,448,919**
Large Farm	$3,055,000	2,030,000	529,930	137,032	**$5,751,962**
Coop Farm	$4,579,000	2,896,000	529,930	195,359	**$8,200,289**
Source Separated Organics	$26,093,000	3,713,000	464,930	1,253,323	**$31,524,253**
Industrial Sector	$23,278,000	4,163,000	487,305	1,354,038	**$29,282,343**
Wastewater Treatment Plant	-	1,977,000	464,930	51,005	**$2,492,935**
Small Landfill	-	4,405,000	551,680	120,967	**$5,077,646**
Medium Landfill	-	6,773,000	2,117,080	216,961	**$9,107,041**
Large Landfill	-	13,542,492	3,364,205	575,409	**$17,482,106**

TABLE 6.2: Capital Costs Required for RNG Production[37]

Demand for RNG in Ontario. In addition to the RNG supply that Ontario could provide, the demand is also in place. Residential and commercial customers in the province appear to have an appetite for a natural gas product that included a blend of RNG and provides environmental benefits. Although neither the LDCs nor retail energy marketers provides such a product, a November 2010 market research study by Ipsos-Reid had identified demand for RNG.[38] This two-phased study randomly surveyed 1052 residential customers and 500 commercial customers on their concern for the natural environment, awareness of RNG, and support for a premium priced RNG product. While only a small proportion of customers were aware of RNG, there was little opposition to the LDCs adopting a proportion of RNG within their product offering (See figure 6.2 and 6.3).

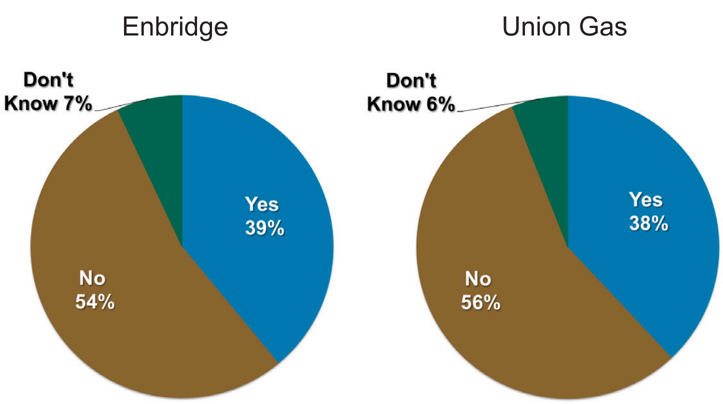


FIGURE 6.2: Customer Awareness of RNG[39]

37 Electrigaz Technologies Inc. (2011). Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Distribution Grid in Ontario.
38 Ipsos Reid. (2010). Bio Methane Survey: Residential & Commercial Natural Gas Customers.
39 Ipsos Reid. (2010). Bio Methane Survey: Residential & Commercial Natural Gas Customers.

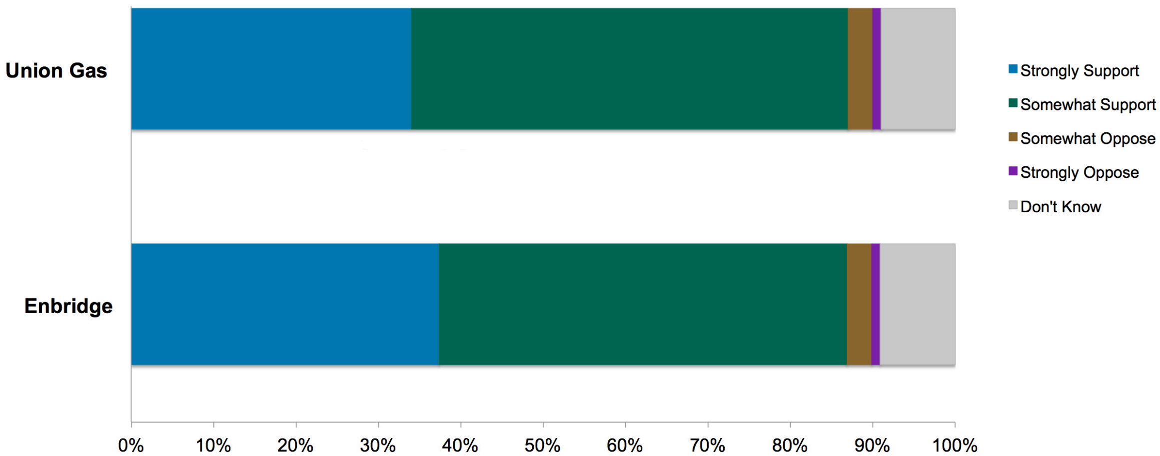


FIGURE 6.3: Customer Support for RNG Program[40]

Of those few customers that had opposed adoption of an RNG program (either strongly or somewhat opposed), about half had claimed that their opposition was based on uncertainty surrounding costs or the potential for a rate increase. This should not come as a surprise considering the attention that the province's renewable electricity programs had garnered around the time of this survey for its costliness to rate payers. Nevertheless, a majority of customers were willing to pay a premium for RNG supply so that their LDC could include a RNG component. Both residential and commercial customers held this support and the highest level was for a program with a 0.5% cost premium. However, a majority of respondents still backed a program that would lead to a 4.0% increase to rates. Table 6.3 reports the levels of support across a number of parameters.

	TOTAL	GENDER		AGE			EDUCATION		
		Men	Women	18-34	35-54	55+	High School or less	College	University
Support 4.0% Increase	57%	54%	61%	49%	55%	60%	57%	50%	61%
Support 2.0% Increase	67%	62%	72%	63%	64%	70%	67%	60%	70%
Support 1.0% Increase	74%	69%	78%	63%	70%	78%	76%	69%	76%
Support 0.5% Increase	76%	73%	80%	63%	73%	81%	78%	72%	78%

TABLE 6.3: Support RNG Program Across Varying Price Premiums[41]

Interestingly, the demand for a RNG program in Ontario far outstrips that identified in a similar survey conducted in British Columbia where FortisBC had already implemented a green pricing program for an RNG product. Yet, customers in Ontario will be unable to satisfy such demand unless both industry players and policy makers make a greater effort to help nurture this industry and support its creation.

Creating an Ontario RNG Industry. Despite the definitive demand for RNG and adequate supply of necessary feedstock and interest by potential developers, the creation of a functioning market in Ontario will not develop organically. The inability of the LDCs to sign long-term contracts for the natural gas supply, the sig-

40 Ipsos Reid. 2010.
41 Ipsos Reid. 2010.

nificant difference between the current price of conventional natural gas, and the premium the utilities would have to pay to RNG developers presently makes the emergence of the industry impossible. It is clear that if a RNG industry is to emerge from the current situation, then regulators and policy makers will have to play a significant role in the effort.

The process of new industry creation rarely occurs without some role for policy makers and/or regulators. Organic growth of a new industry without government support is the exception rather than the rule. Many of today's most ubiquitous technologies and their supporting industries benefited from both direct subsidies and institutional support or indirect backing in the form of government procurement practices or publicly-funded research and development. Some examples include the development of semiconductors in Silicon Valley, flat panel displays in both the US and Asia, and renewable electricity technologies in the US.

Silicon Valley, which now takes much credit for the creation of the computer and information technology industry, greatly benefited from government research and funding at its emergence in the 1950s. In fact, until well into the 1960s this industry had no market for their products with the exception of the publicly funded defense and space industries. In the 1950s, the Army Signal Corps funded research into semiconductors while the Atomic Energy Commission were the first purchasers of supercomputers, which laid the groundwork for today's PCs. Most importantly, the Air Force's air defense project generated numerous innovations in computing design and production during the early 1950s including cheap manufacturing of computer memory, communication between computers, and the use of keyboard terminals. Such support did not slow down, as the US Department of Defense remained the single largest purchaser of computer software well into the 1980's; thereby ensuring a consistent market demand that fueled an ever-growing industry.

The flat panel display industry, which now produces display screens to practically every electronic interface we use (e.g., televisions, computers, phones), had a similar history with significant initial support from the US military. The Defense Advanced Research Projects Agency had worked with major industry players to develop a technology that could be used in military applications but would also have an obvious benefit to consumers. While governments in Japan, South Korea, and Taiwan had provided significant subsidies to the flat panel display industry and relaxed anti-trust provisions to allow their firms to cooperate to enhance the production process to increase yields, improve the technology, and lower costs. Simply put, without such support the industry would not have been able to reach commercial viability as the production process was inefficient and unable to overcome technological obstacles that brought costs down.

Finally, renewable energy technologies have garnered significant support from the US Federal and States' governments from the earliest stages of the their development until the recent commercialization over the past five years. Such support did not only come in the form of tens of billions of dollars of direct subsidies to the industry, but also significant government ownership, substantial funding of energy-related research and development at both government laboratories and post-secondary institutions, price controls, tax exemptions, mandated purchase requirements, and regulatory tools such as feed-in-tariffs, green pricing regimes, and renewable portfolio standards. Such efforts have allowed wind and solar power technologies to develop to the point that allows them to now effectively compete with traditional generating technologies and provide a significant engine for economic growth. Yet without this government support and the uncertainty over carbon pricing policy, the commercial viability of such technologies would be unlikely and the industry would still be struggling to emerge.

These three examples demonstrate the importance that policy makers can provide to help industries overcome early challenges. The state of the RNG sector in Ontario represents such a case. Despite the presence of both abundant demand and supply, the industry will never emerge since the institutional framework prevents the LDCs to effectively broker the transaction. For emergence and subsequent maturation, the industry requires suppliers of RNG to (1) be able to sell the RNG at prices that would provide for a reasonable rate of return and (2) have the requisite stability to ensure they could attract the capital required to make the initial investment. Therefore, changes to the Ontario regulatory framework would be required to allow the LDCs to contract with suppliers over a longer window and pass on the higher costs required for purchasing the RNG to ratepayers. Without regulatory support to ease these two challenges, the RNG industry will face severe difficulty getting off the ground as forecasted natural gas prices are expected to increase over the next 15 years but not to the extent that would make RNG investments profitable under current economic assumptions (See Figure 6.4).

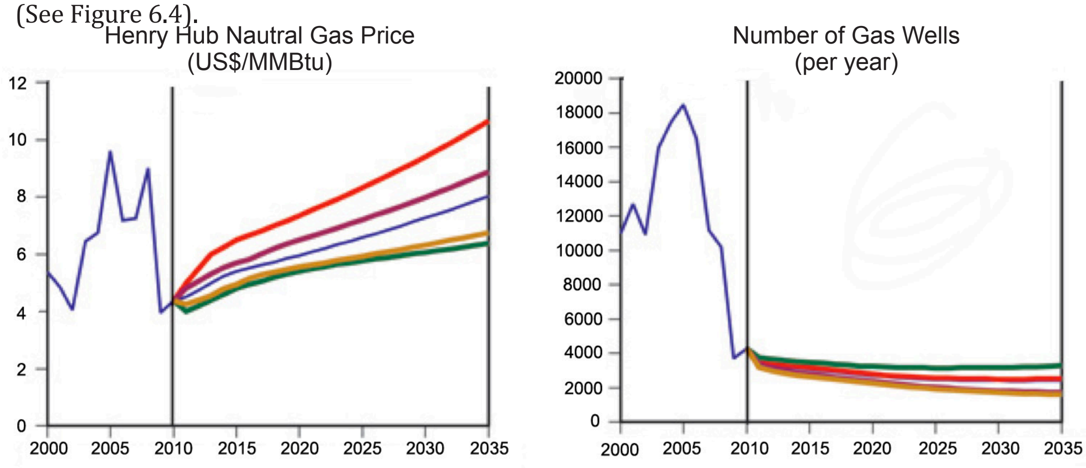


FIGURE 6.4: Forecasted Natural Gas Prices[42]

6.2 ONTARIO POLICY ENVIRONMENT

For the RNG market place in Ontario to be successful, provincial regulator and policy maker support is needed. Just as FortisBC was able to gain approval for a premium priced RNG product in British Columbia, UGL and Enbridge would need public support for their own efforts to successfully materialize. At the minimum, this requires energy developers to have a fair price and a predictable framework to support the initial development of RNG in Ontario.

6.2.1 THE POLITICAL CLIMATE FOR RENEWABLE POWER IN ONTARIO

The province of Ontario is acknowledged as having adopted a range of aggressive and progressive approaches to a range of environmental issues. For instance, Ontario established a staggered set of GHG reduction objectives that would see a 6% reduction in emissions below 1990 levels by 2014 and 80% below those historical levels by 2050.[43]

The initial policy mechanism for reaching these objectives was a commitment to close the province's coal-fired electricity generating plants. These plants had at one time provided for a fifth to a quarter of the province's electricity supply. At the same time, with growing demand in the province, additional supply was identified as needing to come from other cleaner sources. In response, the province of Ontario launched a variety of initiatives to generate new power, including the construction of natural gas fired electricity generation plants and district energy systems with combined heat and power capacity. [44]

42 Source: National Energy Board of Canada, November 2011. Canada's Energy Future: Energy Supply and Demand Projections to 2035.

43 Ontario Action Plan on Climate Change. (2007). Retrieved at http://www.ene.gov.on.ca/environment/en/resources/STD01_076574.html

44 Although an important energy closing gap policy response, it is acknowledged that natural gas could be targeted for reduction via carbon pricing or cap and trade policies. Expanding Ontario's natural gas network to include RNG is another option for maximizing new energy infrastructure investment and ensuring cost effective delivery of thermal energy to millions of homes and businesses.

The provincial government also undertook other bold moves to combat GHG emissions with a series of programs intended to stimulate growth in renewable electricity generation. One such effort was the Renewable Energy Standard Offer Program (RESOP) that was introduced in 2006 (following Renewable Energy Supply request for proposal programs in 2004 and 2005, called RES I and RES II) and offered a base price for electricity from renewables regardless of the technology used for a guaranteed 20 years. This program was oversubscribed and a different approach was sought, which led to the program being discontinued in May 2008.

Despite the practical implementation issues, RESOP demonstrated the great interest in renewable power in the province and the necessity to provide suppliers with a stable and transparent framework for implementing their investments. As a result, the government introduced the Green Energy and Green Economy Act of Ontario (more commonly referred to as the Green Energy Act, or GEA) in May 2009. The GEA introduced a more comprehensive feed-in-tariff regime that promoted both small and large scale renewable energy generation by providing long-term contracts and compensated based on size of project and technology used and stream- lined the approvals process. The GEA was designed to make Ontario a leading green economy in North America and its three objectives:[45]

1. Spark growth in clean and renewable sources of energy such as wind, solar, hydro, biomass and biogas in Ontario.
2. Create the potential for savings and better-managed household energy expenditures through a series of conservation measures.
3. Create 50,000 jobs for Ontarians in its first three years.

Despite its name, however, the GEA focused on power and was more aptly referred to by the utility community in Ontario as the "Green Electricity Act." As a result, Ontario's natural gas distributors had few options to get involved in this ambitious program. Although there was a premium price provided for electricity generated from raw biogas, the GEA did not include new province wide sources of renewable energy, such as RNG.

6.2.2 THE PIVOTAL REGULATORY AUTHORITY IN ONTARIO

Despite a climate of support for renewable energy, a market for RNG could not emerge without the requisite regulatory approval. The Ontario Energy Board (OEB) represents the pivotal regulatory body in the province and would review any application by natural gas distributors to procure RNG and pass on the cost to consumers.

The OEB was created as an economic regulator. It was created to be responsible for setting just and reasonable rates in both the electricity and natural gas sector that could allow regulated utilities to realize fair returns. Over the past fifteen years, however, it has been a central player in a series of new initiatives from creating a competitive market for energy services to achieving the objectives of conservation, promotion of renewable generation and technological innovation through the smart grid. As a result, the OEB is expected to balance differing priorities that, at times, are at odds with one another.

The new workload facing the OEB meant that any application that was outside of the very structured and well-established process of regulating rates would need to pass the tests of (I) good public policy and (II) customer demand.

The risk of filing an application that was beyond the OEBs traditional areas of focus created the potential for the OEB to claim that the application was outside its jurisdiction and would prevent the applications by UGL and Enbridge for RNG from advancing any further. For instance, in a 2009 rate case, Enbridge had sought to include within its rate base investment costs related to the creation and distribution of alternative forms of

45 Green Energy Act, 2009, S.O. 2009, c. 12.

energy as part of a Green Energy Initiatives program. The case faced opposition by over a dozen interveners and the OEB ruled that it did not have the jurisdictional scope to rule and even if it had, it would choose not to include the costs in the firm's rate base. Furthermore, the OEB found in this case that a September 2009 Ministerial Directive, which authorized Enbridge to engage in activities related to conservation, demand management, and renewable energy, did not support the utility's intent to include the costs of such investments within its regulated rate base.

Based on the past experience of the LDCs, it was acknowledged by the industry that an application to the OEB regarding RNG would need to be focused on issues that were germane to the issue and had a clear ask.

6.2.3 POLICY STABILITY AND UNCERTAINTY IN ONTARIO

While Ontario had been assertive and forward reaching relative to other North American jurisdictions in adopting new policies to address a range of environmental problems (e.g., landfill gas capture and renewable electricity), the capacity of the Ontario Government to remain committed and consistent to such a diversity of environmental initiatives was being called to question by media, opposition parties and the energy industry. [46]

Renewable energy developers have pointed to several examples of instability in the energy public policy environment in Ontario, including the revolving- leadership at the Ministry of Energy (i.e. six ministers in less than six years) and the series of ministerial directives that appeared to alter the operations of the OEB, Ontario Power Authority (OPA) and Ontario Power Generation (OPG).

This perceived policy instability in Ontario was further exacerbated by the uncertainty in the future of a carbon pricing regime, either in the form of a carbon tax as in British Columbia or cap and trade system like that adopted in Europe or California. For instance, reducing the carbon intensity of a product, such as natural gas with the use of RNG and doing so in a manner consistent with current and potential future public policy would seem prudent. With billions of dollars invested in the natural gas transmission and distribution networks in Ontario, both UGL and Enbridge have assets that could also serve the public good through innovation.

Once the province's four remaining coal-fired power plants are closed the last remaining hydrocarbon-based electricity generation source in Ontario will be natural gas. The uncertain political environment in the province could potentially leave this sector open for a dramatic shift. This possibility is not farfetched as the Government of Ontario has already reversed its support for the siting of two separate natural gas power plants. Going forward, advancing RNG is a prudent approach for the industry to balance interests, address public policy priorities and innovate.

6.3 THE JOINT APPLICATION AND ITS CHALLENGES

In the fall of 2011, UGL and Enbridge were prepared to take the leap into RNG with a well-structured program that would not only be consistent with public policy in the province but also meet the expectations of their ratepayers. The "Renewable Natural Gas Application" was filed jointly between both utilities with the OEB on September 30, 2011.[47] According to its cover sheet:

> The purpose of this application is to establish a Renewable Natural Gas ("RNG") Program to enable the development of a viable industry in Ontario. This will allow the benefits outlined in this evidence to be realized. The benefits represent significant opportunities, including the opportunity to offer greater choice for energy consumers, and the opportunity to maximize the efficient use of biogas resources. Establishing a RNG Program now, when these opportunities are available, will ensure that these benefits are not passed over.

46 Holburn, G. L. F., Lui, K. and Morand, C. (2010) "Policy Risk and Private Investment in Wind Power: Survey EviOntario". Canadian Public Policy.

47 Cases *EB-2011-0283* (Union Gas Limited) and EB-2011-0242 (Enbridge Gas Distribution).

The utilities believed that this forward-looking approach, which placed industry emergence above their own financial performance, was fundamental to its success in the regulatory process. Since the application was quite different from what the OEB would regularly review, they had to include additional elements as part of the application such as a market research report conducted by Ipsos-Reid, a brief on the potential of RNG by an Alberta government research group (Alberta Innovates Technology Futures), and over a dozen letters of support from various municipalities and relevant stakeholders. The opportunity to transform the market and diversify their supply of natural gas to take on environmentally responsible attributes was obtainable, yet the UGL and Enbridge had to ensure that the details of the plan were simple and transparent.

6.3.1 A REFERENCE PRICE WITH LONG TERM CONTRACTING

In the short-term, the utilities understood that the two primary sources of RNG in the province would be from anaerobic digestion processes at farming operations and landfills.[48] Neither utility had an interest in making a capital expenditure in the RNG production process, as it was evident that the OEB would likely not allow such investments to be included in their regulated rate base. As a result, small or mid-sized developers would need to be attracted to enter RNG production and supply the utilities that would act as market enablers and distribute a blended product to their customers. Such local sourcing arrangements were already a key part of the utilities' supply strategy for sourcing Ontario produced natural gas from over 100 locations.

Unlike the traditional supply relationships, the prospective RNG developers would require the certainty of stable revenue streams and a reasonable return to be able to attract the necessary financing to make the initial investment in digestion machinery (where necessary), upgraders, and injection equipment. Such certainty was available under the province's FIT program but that did not apply to the development of injectable RNG. This presented a significant obstacle for the utilities since they were required to purchase natural gas at market rates and were not allowed to enter long-term gas supply contracts. As a result, the market for RNG would not be able to develop organically since it would require a premium price for the supply and greater certainty. For this reason, the first major facet of the RNG application was the ability to develop a pricing framework for 20-year supply contracts. This program would be similar to a feed-in-tariff but the application made it clear that these exceptions to their business model would not be precedent setting. Rather that these exceptions would be necessary to add yet another sliver of natural gas supply and would be prerequisites for the emergence of a RNG market.

In setting these terms, the utilities took every effort to ensure that they were consistent with the province's current FIT regime for electricity. The 20-year period would provide developers with long-term certainty and was identical to that under FIT. The premium prices that would be provided by the utilities to the developers would allow for about an 11% return on equity, which again would be similar to that offered under FIT. Based on an analysis provided by a leading biogas engineering firm, Electrigaz Technologies Inc., the utilities chose to offer pricing tiers that differed for RNG sourced from landfill sources and anaerobic digestion processes. Both included a "breakpoint" that reduced the price paid once the operation surpassed a particular annual quantity of RNG produced (See table 6.4).

48 In fact, UG had already some interest from a firm in Leamington, Ontario that owned and operated an anaerobic digester that accepted organic waste that was transformed into raw biogas.

RNG Supply Source	Annual Breakpoint (by Site)	Supply Price Under Breakpoint	Supply Price Above Breakpoint
Landfill Gas	150,000 GJ	$13/GJ	$6/GJ
Anaerobic Digestion	50,000 GJ	$17/GJ	$11/GJ

TABLE 6.4: RNG Supply Pricing[49]

While the prices paid for RNG would represent a significant premium on the current market price for natural gas, the greater challenge in this facet of the application would be the long-term contracting. The OEB had maintained the position that both utilities were strictly prevented from entering long-term supply contracts. On the surface this may appear counter-intuitive as such longer-term contracting options could provide price stability and hedging opportunities in what at times could be a volatile market. However, Ontario's deregulated natural gas market distinguished these utilities from energy marketers who were permitted greater freedom to source natural gas as they wished through either short or long term contracts However, if certainty cannot be brought to contracts for RNG then the market will not emerge until either natural gas prices increase significantly or the cost of capital expenditures drop precipitously.

6.3.2 MEETING CUSTOMER DEMAND WITH LIMITED IMPACT TO BILLS

The Ontario market primed for the emergence of a RNG sector would require regulatory approval for customers to bear some of the costs for appropriate cost recovery. With the pricing structure sought in the application and current market prices of conventional natural gas at or near record lows there would have to be subsidization by the customer for the program to work. The Ipsos-Reid market research study clearly demonstrated that there was tolerance for natural gas rates to rise in order for the utilities to provide a more environmentally responsible product. However, as the province's FIT program had demonstrated such tolerance is limited. The last thing the utilities would want to happen with their application would be a negative customer response to the price premium and an onslaught of intervening groups lining up to be involved in the OEB hearing process.

Therefore, in an effort to offer customers the choice of RNG and get a functioning industry to emerge in Ontario the utilities developed a transparent and structured system that would limit the cost to customers. The key mechanism would be a supply cap that would constrain how much volume of RNG that either UGL or Enbridge would be able to source. This cap would be no more than 2% of their total supply portfolio, which would equate to 2.2 PJ for UGL and 3.3 PJ for Enbridge. Once this supply cap was met for either utility they would no longer be able to offer the price premium and 20-year contract. To constrain supply even further, the application included a sunset clause that would only allow the utilities to offer the 20-year contracts for five years from the OEB's approval of the application. This meant that the program would terminate new contract offerings in five years irrespective of whether either utility was able to meet their supply cap or not.

Limiting the bill impact for customers was a priority for the program to work but they would also need to ensure that there would be enough interest and investment in RNG. As result, the utilities had considered different supply cap scenarios and the resulting impact that they would have for the average customer (See Table 6.5). Both utilities settled on a maximum yearly increase in customers' rates of about $18 for an average natural gas customer. This price premium would only be met at the point where they had reached the ceiling of their supply cap (2.2 PJs for UG or 3.3 PJs for Enbridge). As a basis of comparison, the carbon tax in British Columbia placed a 4.75¢/m^3 premium on natural gas, which would result in a $122 annual premium for the

49 Renewable Natural Gas Application. 2011.

average customer.[50] Furthermore, this premium would be accounted for in the utilities' *Gas Supply Charge* on customers' bills, which meant that if a customer disagreed with the program they could seek an alternative gas supplier in the form of an energy marketer. This ability to opt out of the utility gas supply program distinguished the RNG application further from the FIT program. Under FIT all customers had to bear the costs of renewable generated electricity in the *Global Adjustment*[51] on their bills, regardless of whether they purchased their electricity from a utility or from an energy marketer.

RNG Volume (PJs)	0.5	1.0	1.5	2.2
Approximate Bill Impact ($/year)	$3.50 to $4.50	$7.50 to $8.50	$10.50 to $12.50	$18

TABLE 6.5: Bill Impact at Various Supply Caps for Union Gas Customers[52]

Despite the limited premium that would be passed on to customers and their ability to opt out of the program by signing a contract with an energy marketer, the utilities had expected there to be some push back on this issue. In fact, when the OEB decided that there would be oral hearings for the RNG application on October 21, 2011 there were already twenty groups that had filed for intervention status. This included cost-conscious groups like the Vulnerable Energy Consumers Coalition, the Building Owners and Managers Association Toronto, Canadian Manufacturers & Exporters, and the Consumers Council of Canada.

Despite the opposition, the utilities would not only be able to point to the programs relative advantages and transparency vis-à-vis the province's FIT program but also how with little cost there could be a considerable benefit to the natural environment without any change in behaviour or technological complications. This is an important distinction, as most environmentally beneficial advances require significant changes by other energy producers or consumers, such as interconnecting a disparate set of renewable electricity projects or smart meters. Sourcing and blending RNG as part of a diversified natural gas fuel mix would require neither. Finally, should RNG provide economically-valuable attributes, such as renewable energy credits, in the future the application was clear that these would belong to the consumer and be used to lower their gas supply cost.

6.3.3 TRANSPARENT AND STREAMLINED SUPPORTING STRUCTURE

Beyond trying to provide a consumer friendly approach to helping to meet the province's ambitious GHG emissions reduction targets, the application placed considerable emphasis on providing a clear and transparent supporting structure. This meant not only laying out a straightforward pricing and cost recovery mechanism but also clearly outlining the costs that RNG developers would incur and the processes for tying into the natural gas distribution (or transmission) infrastructure. While the technology required to produce and upgrade raw biogas to RNG was well established, the utilities could not afford to have producers supplying a sub-par product that did not meet their industry leading standards for gas composition.

Since the utilities were not making any capital investment as part of the RNG application it had to be transparent as to what the rights and responsibilities of the producers would be since they would be relied up for driving the emergence of the sector. The details of the proposed RNG contracts were quite similar to those already used for the utilities and their local supplier network for conventional natural gas, but had some alterations to facilitate RNG. The application clearly outlined the (a) connection procedure and capital cost contributions for

50 British Columbia Ministry of Finance. (2011). How the Carbon Tax Works. Retrieved at http://www.fin.gov.bc.ca/tbs/tp/climate/A4.htm

51 According to the Independent Electricity System Operator (IESO) the Global Adjustment included payments made to suppliers that have been awarded contracts through the Ontario Power Authority such as new gas-fired facilities, renewable facilities (like wind farms) and demand response programs.

52 Renewable Natural Gas Application. 2011.

RNG producers to inject gas, (b) gas quality standards[53], and (c) allocation mechanism to ensure equitable access to the distribution (transmission) network. Each application to supply RNG to a utility would be assessed individually and provided a maximum volume to be supplied under the approved price system for the twenty-year contracting period. The utility would have exclusivity to the RNG from that producer and would be responsible to determine whether there would be capacity at an interconnection tie-in for the RNG supplier to tap into the natural gas network. In the case of multiple producers coming forward for a common tie-in there will be a transparent allocation system to ensure multiple producers have equitable gas network access. It will be based on a first come, first served basis with onus on producer to confirm serious intent.

The tight structure of the application represented an important strength that should prove to be difficult to ignore in the regulatory hearings. It differentiated itself from Ontario's FIT program by placing the entire burden of the process on to the LDC's. In essence, UGL and Enbridge would "own" the administrative process and ensure that it was streamlined with clear accountabilities. While technical assessments for connection tie-ins would be required, as is the case with the FIT program, the distinction would be that the LDCs would be able to offer themselves as a single point of contact for any developer interested in entering the RNG market.

All connection issues would be administered within the utility and be clear and concise. The biggest technical issue would be the capacity of the line at any injection point, which the utilities would need to assess at the network's summer capacity when natural gas demand is at its lowest point. A secondary issue would be the injection pressures as each injection location has different requirements. Nevertheless, both of these technical issues were minor in comparison to those faced by the electricity sector and could be expeditiously resolved by the utilities.

53 The Canadian Gas Association (CGA) formed a Task Force that has defined technical guidelines for acceptable composition of RNG. More information at www.cga.ca

7. CONCLUSION

As a technically feasible and an economically viable alternative to hydrocarbon-based technologies, renewable natural gas deserves serious consideration as another alternative to help support the bold GHG emission reduction targets that Ontario has committed to meeting in both the near and long term. However, for the RNG industry to emerge there needs to be a program that reaches beyond that of the current GEA. Both the demand and supply for RNG are abundant in the Ontario market, but what is missing is a fair price and contracting infrastructure that would allow utilities to enable a more rapid deployment of the RNG industry.

The market fundamentals and efficiency gains seem to favour biogas use for RNG over electricity generation, yet the Ontario GEA does not specifically address this market opportunity. The challenges facing the Ontario joint application are considerable yet the model proposed by Ontario's natural gas utilities should make it with viable under the current OEB regulatory structure. The next step will be the oral interrogatory hearings where UGL and Enbridge Gas Distribution will need to argue for their application by pointing to the local benefits to farmers and municipalities and how the transparent and cost accounted program addresses the concerns of interveners.

Potential Production of Renewable Natural Gas from Ontario Wastes

By

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Alberta Innovates Technology Futures

May 2011

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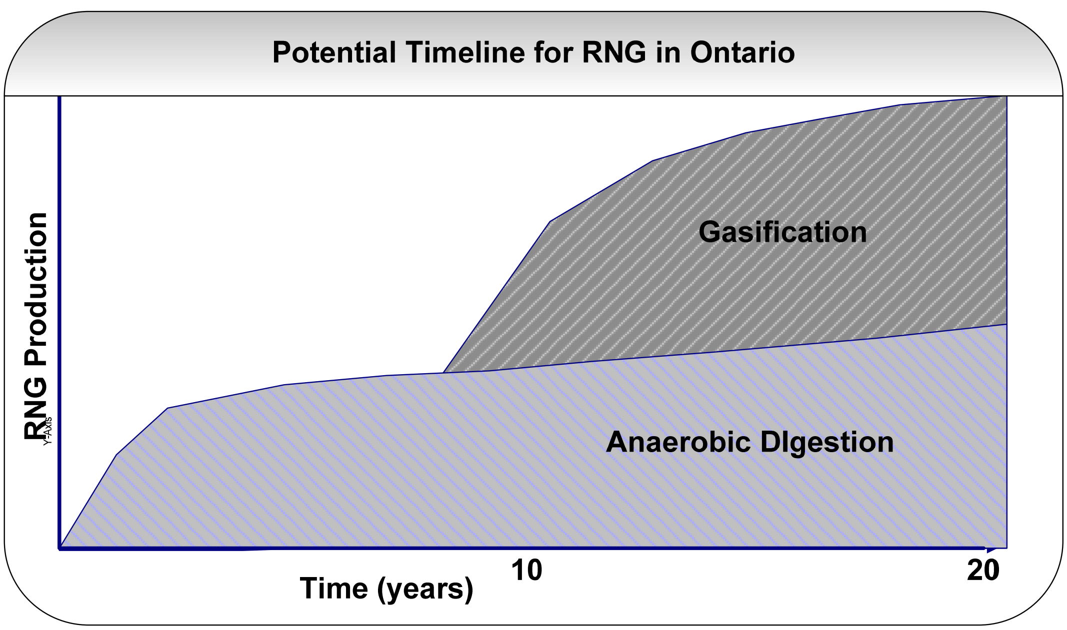
EXECUTIVE SUMMARY

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.

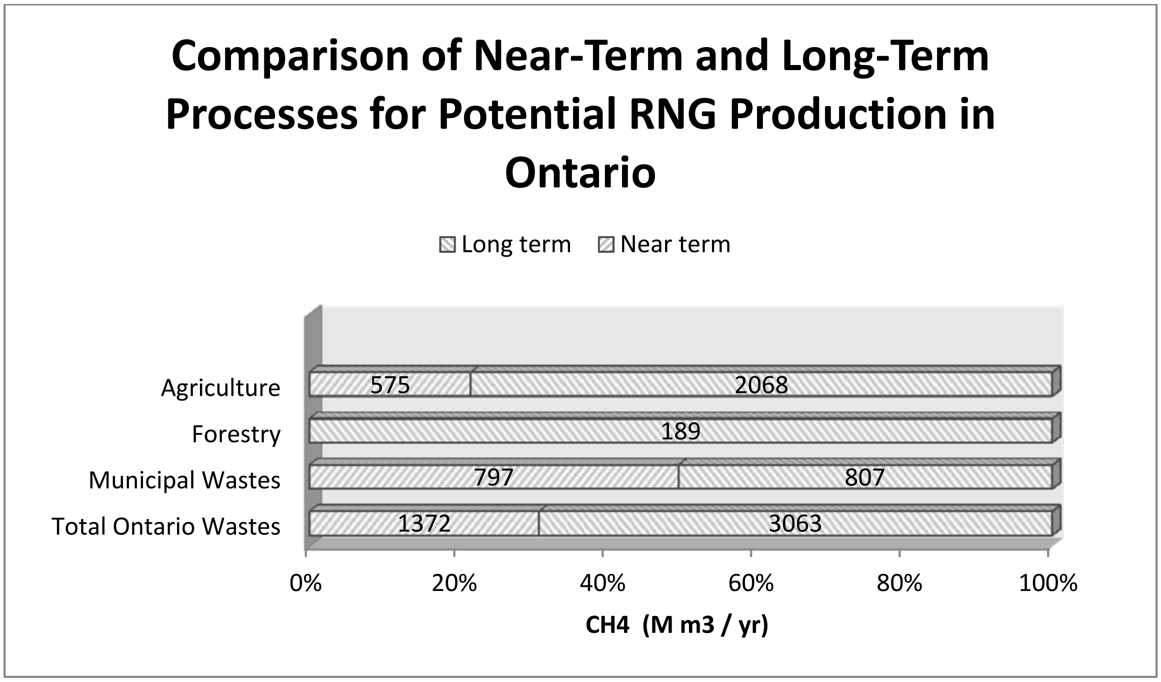


The Ontario wastes which are amenable to producing RNG are those containing significant amounts of biomass and are mostly generated by the agricultural, forestry and municipal sectors.

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.

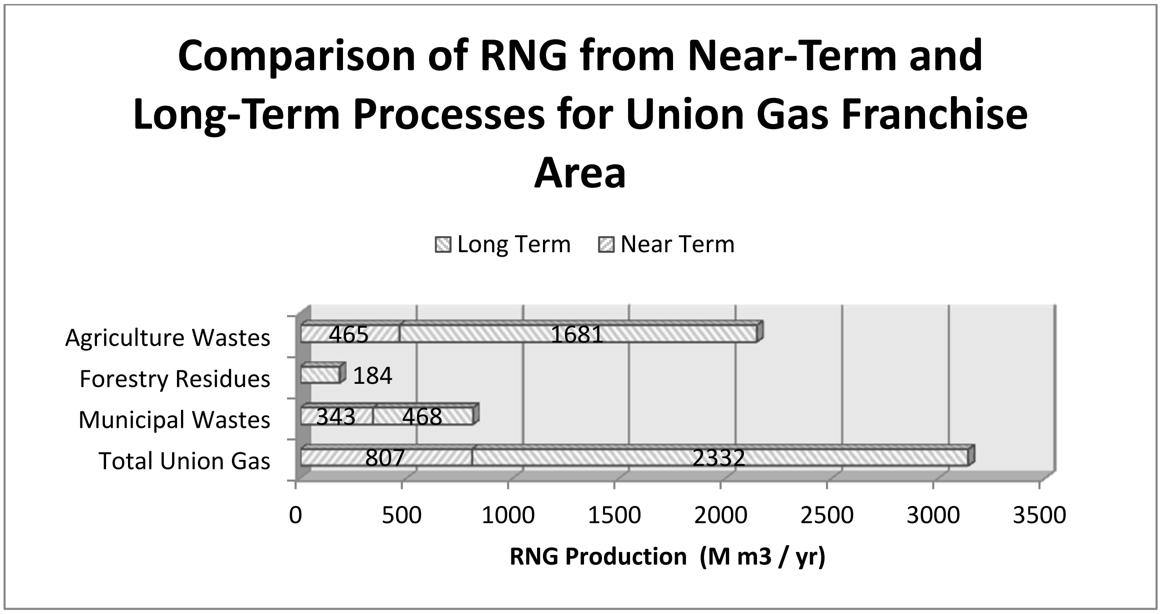
The following approach was used to allocate waste sources to either Enbridge or Union Gas. First, population data was reviewed on a county basis and allocated to either franchise based upon their service area. The ratio of Ontario population per franchise area was used for RNG calculations for all municipal 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.

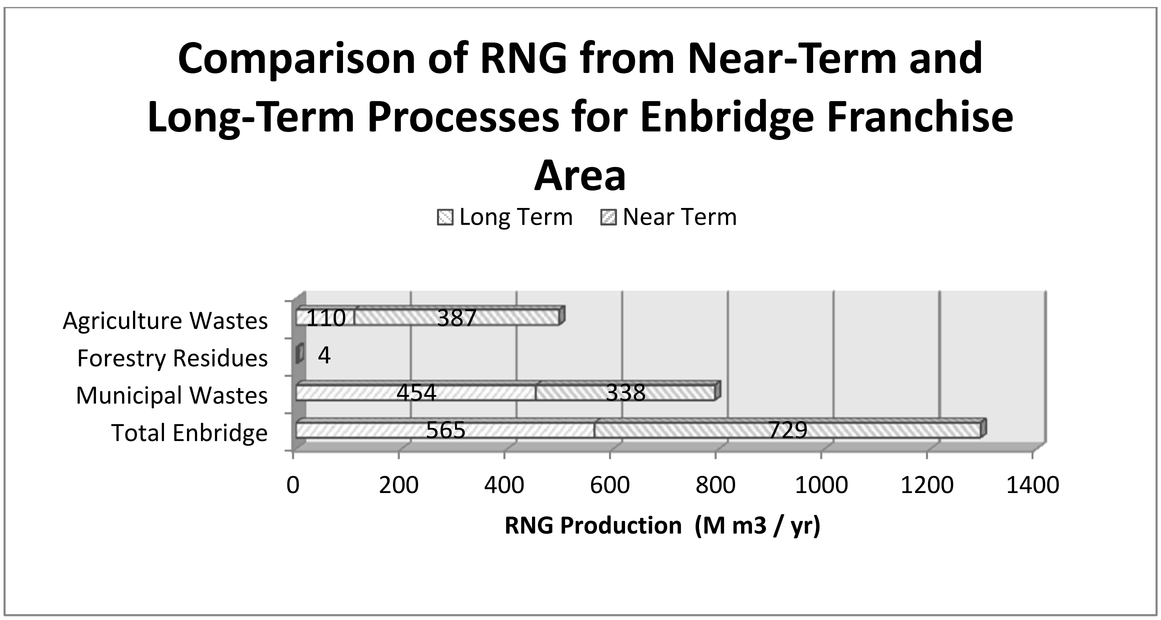
In a limited number of cases, some counties were serviced by both franchises. With these counties, the proportion of population was allocated to either franchise and this ratio was used on the waste volumes for RNG calculations. Additionally, the cities of Kitchener and Kingston operate independent municipal 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

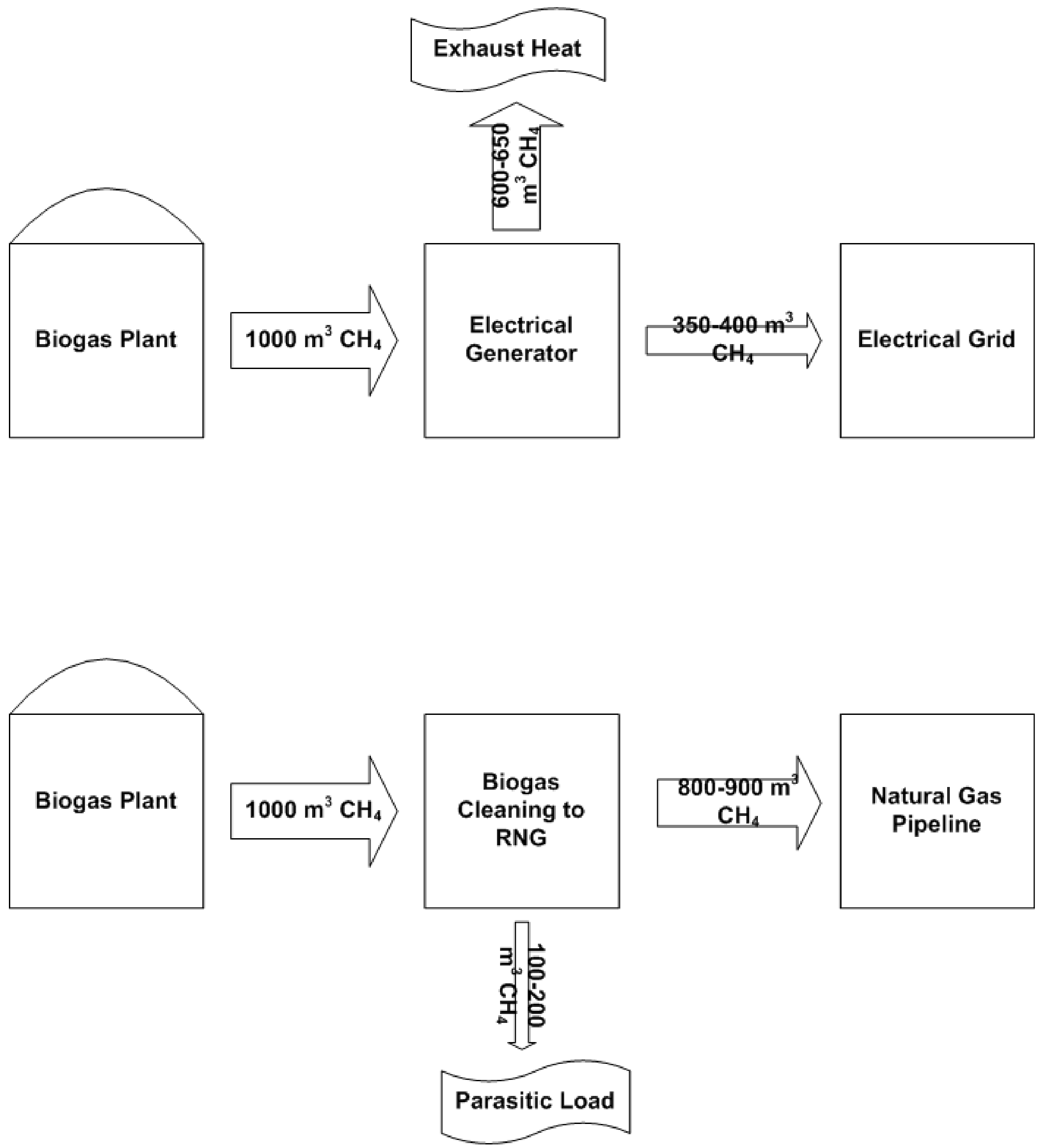
6 Calculated as a percent of the total GHG (column 6)

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 m3 CH4
Biogas Plant
1000 m3 CH4
Electrical Generator
350-400 m3 CH4
Electrical Grid
Biogas Plant
1000 m3 CH4
Biogas Cleaning to RNG
800-900 m3 CH4
Natural Gas Pipeline
100-200 m3 CH4
Parasitic Load

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.

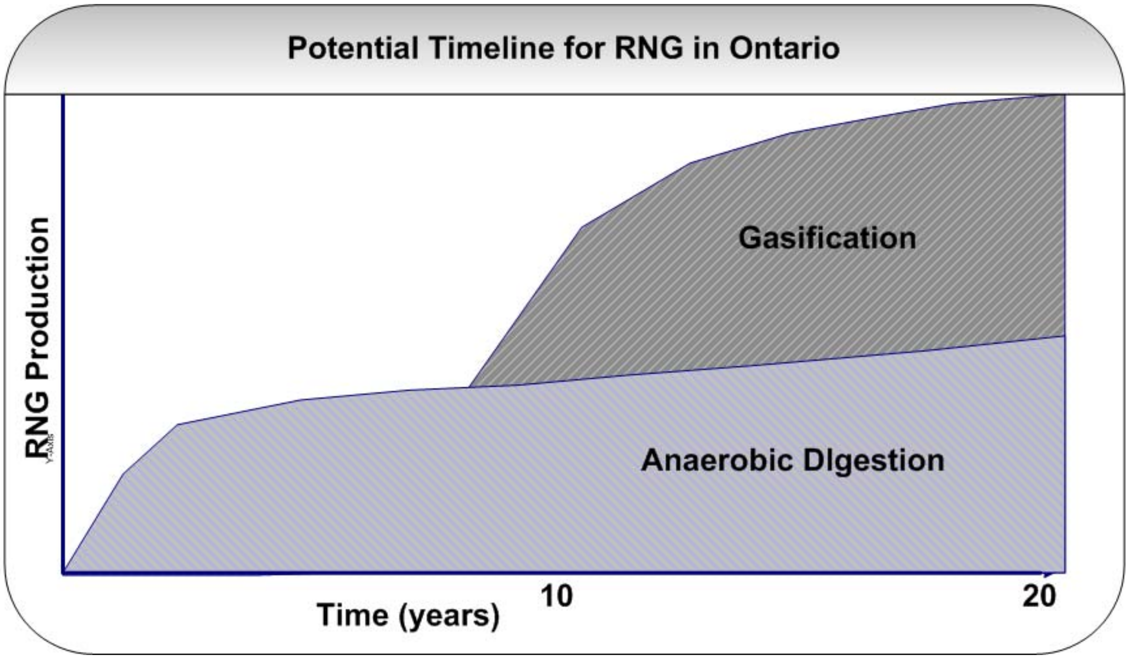


Figure 1. Potential Timeline for RNG Production in Ontario.

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.

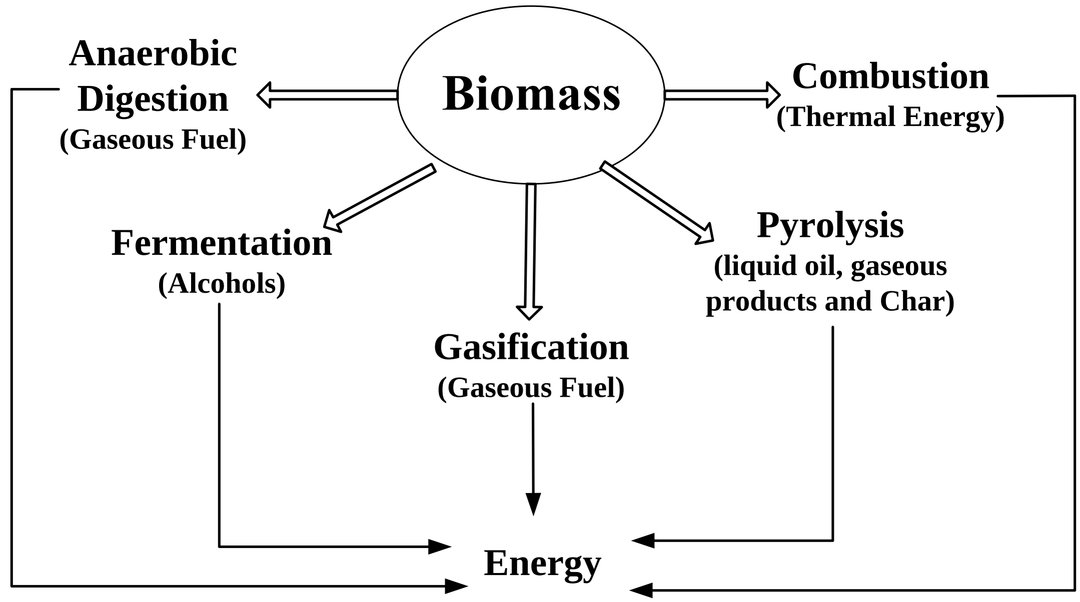


Figure 2. Potential Pathways for Energy Production from Biomass.

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]) Methane (M m3/yr)	Long-Term (Gasification[10])	Total Manure[11]
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

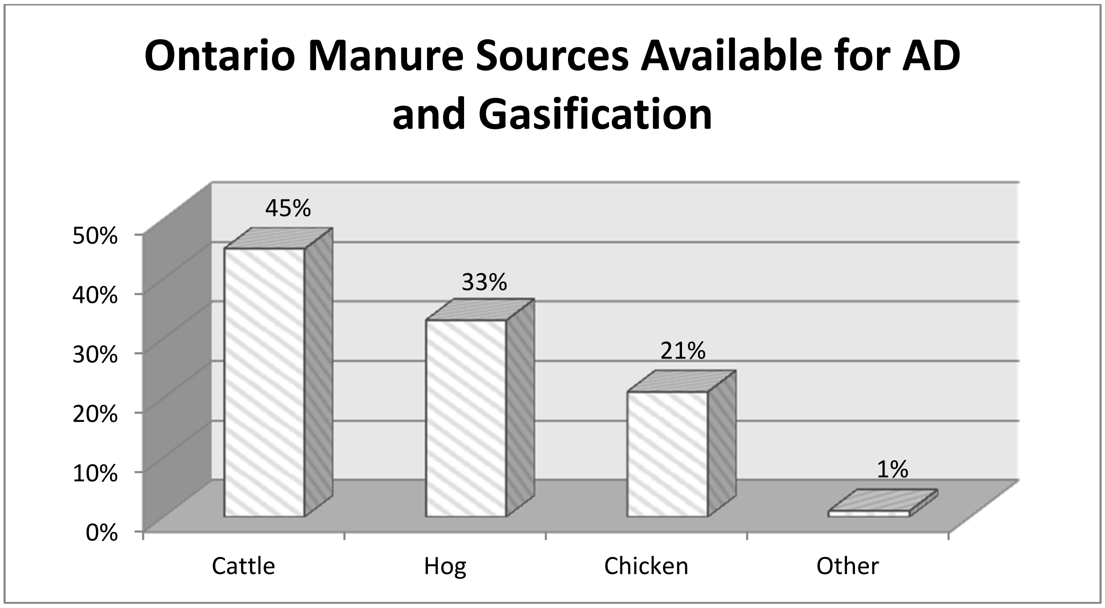


Figure 3. Ontario Manure Sources Available for AD and Gasification

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).

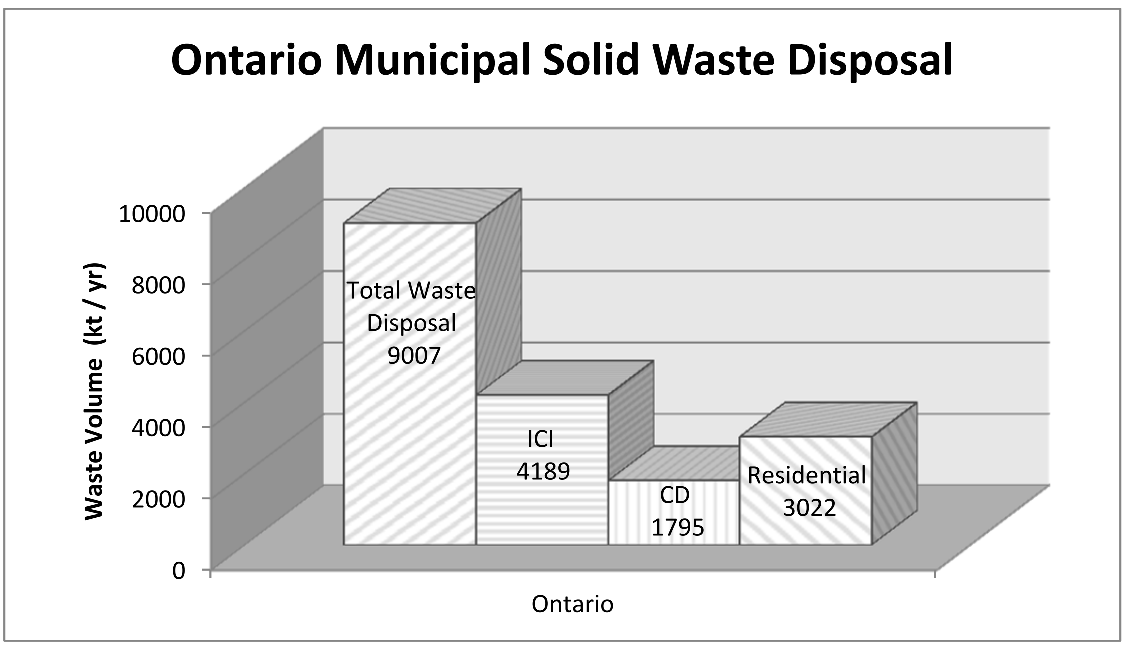


Figure 4. Ontario Municipal Solid Waste Disposal

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 Landfills

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 Near-Term RNG Potential from Landfill Gas

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.

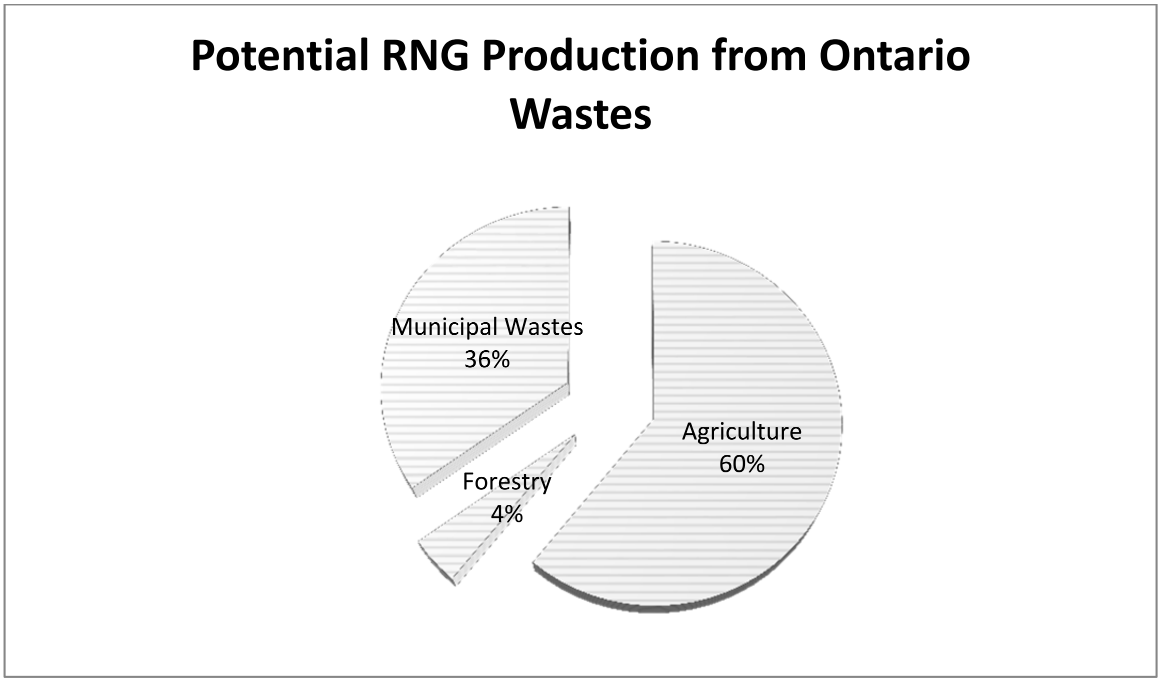


Figure 5. Potential RNG Production from Ontario Wastes.

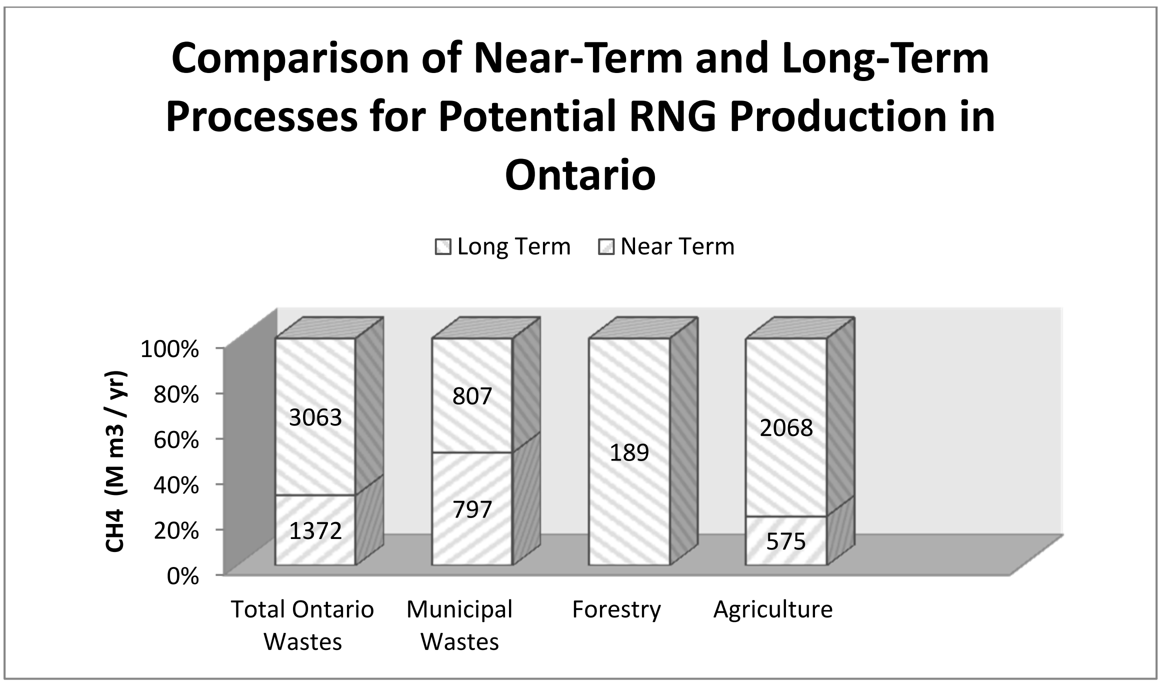


Figure 6. Comparison of Near-Term and Long-Term Processes for Potential RNG Production in Ontario.

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.

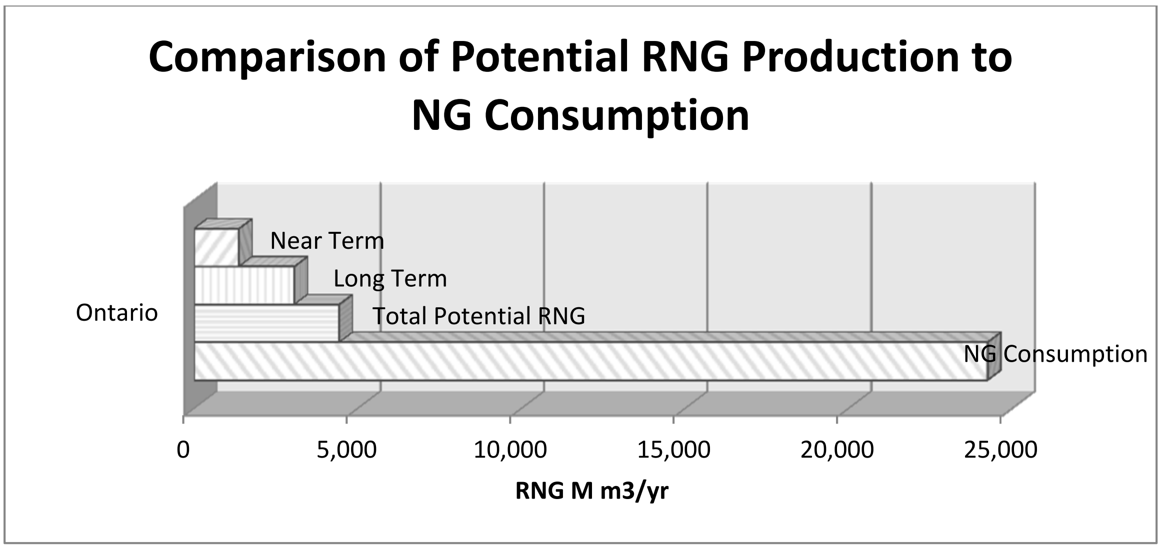


Figure 7. Comparison of Potential RNG Production to NG Consumption

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.

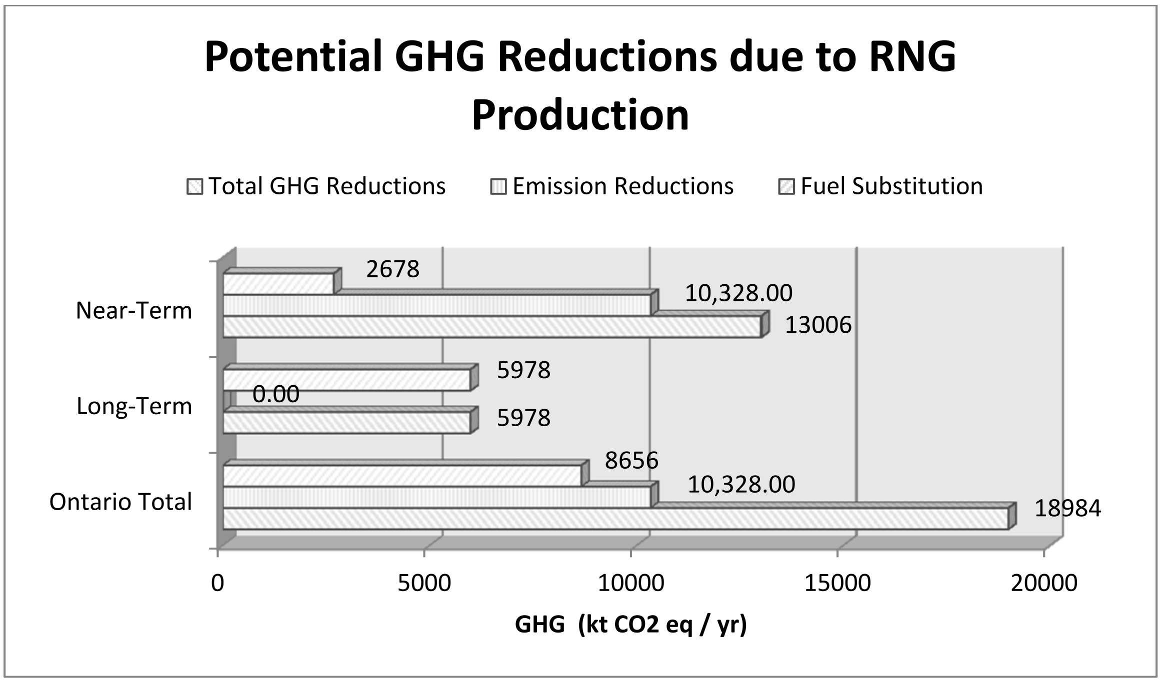


Figure 8. Potential GHG Reductions due to RNG Production

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.

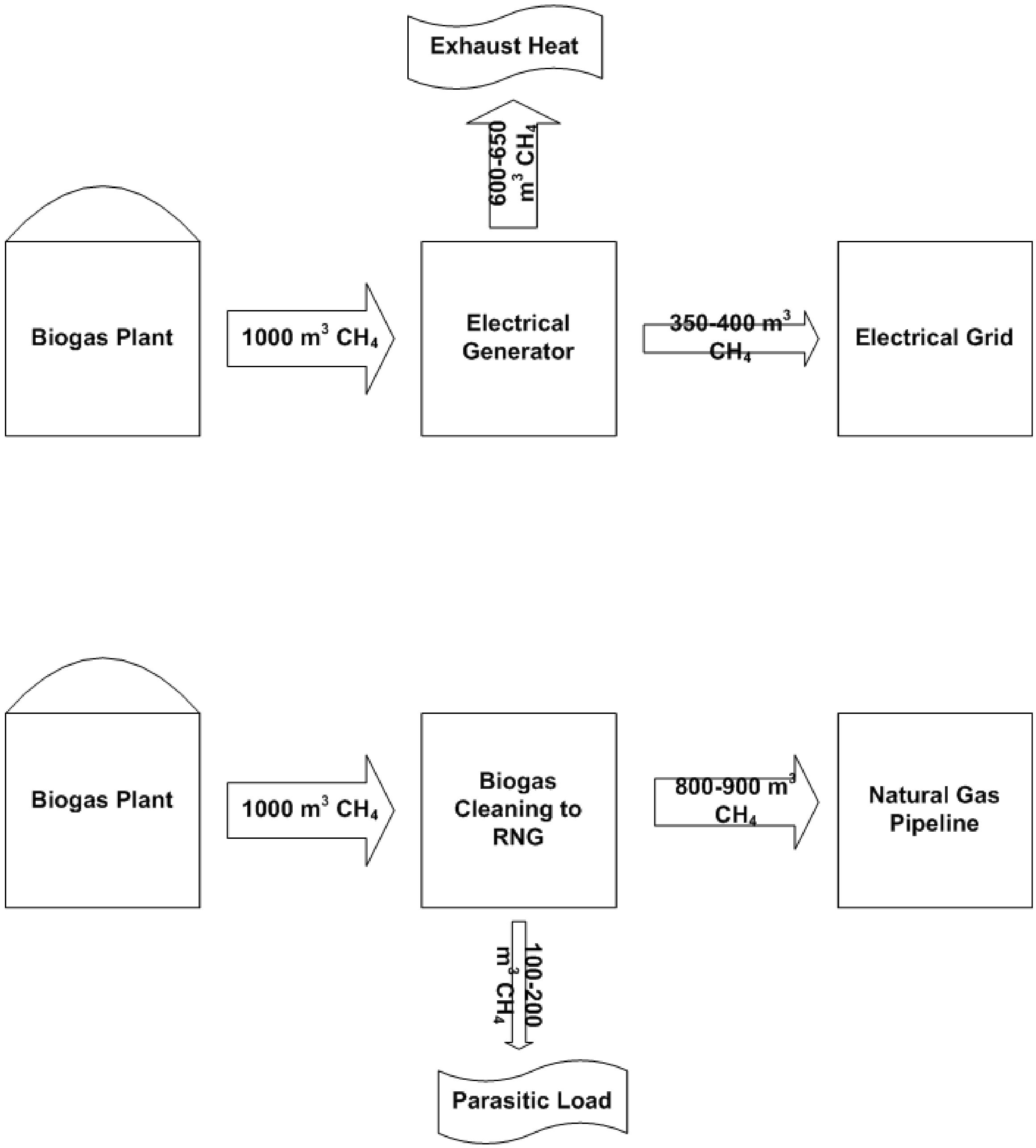


Figure 9. Comparison of Biogas Energy Retained when used for Electricity Generation or RNG.

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.

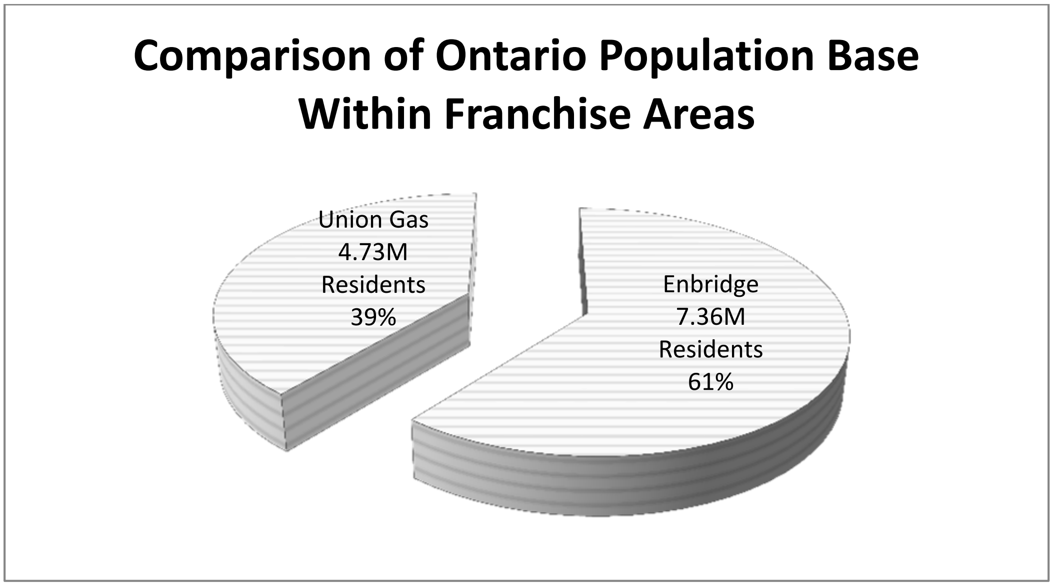


Figure 10. Comparison of Ontario Population Base within Franchise Areas.

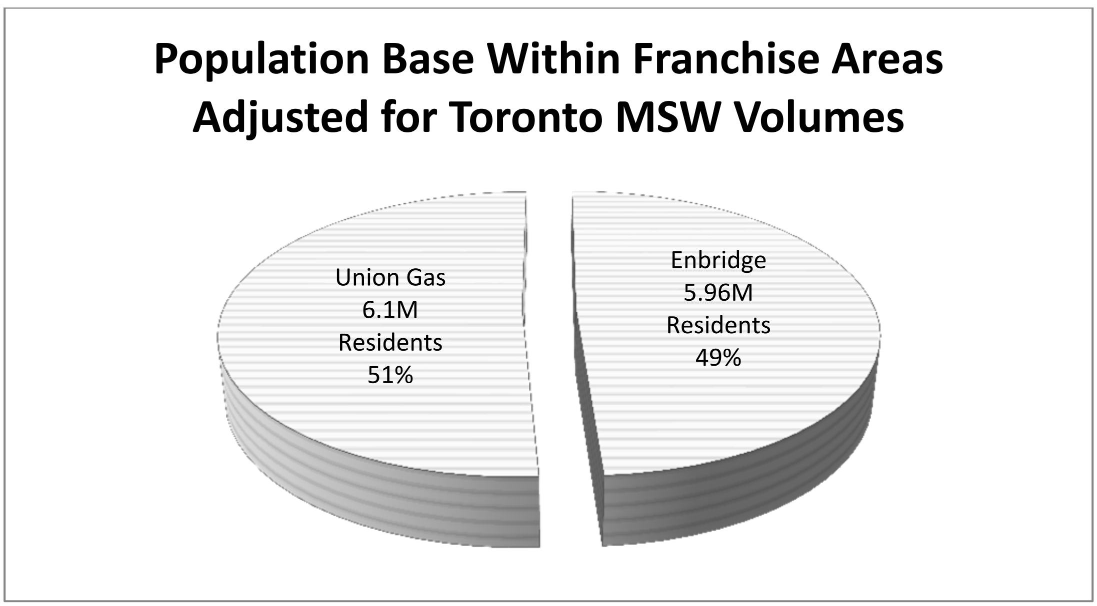


Figure 11. Population Base Within Franchise Areas Adjusted for Toronto MSW Volumes.

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

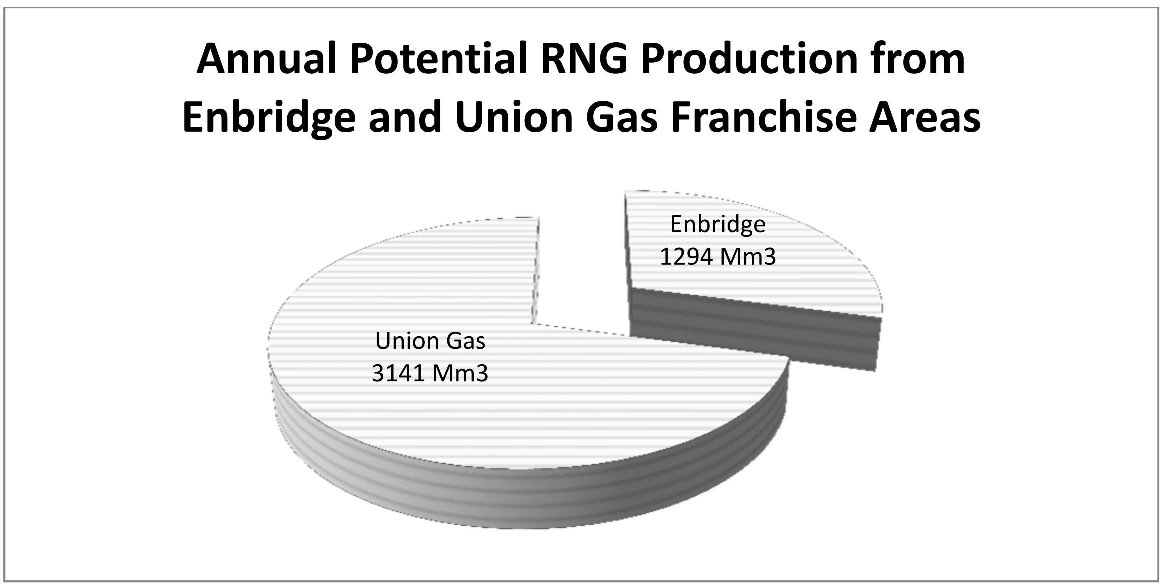


Figure 12. Annual Potential RNG Production from Enbridge and Union Gas Franchise Areas.

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.

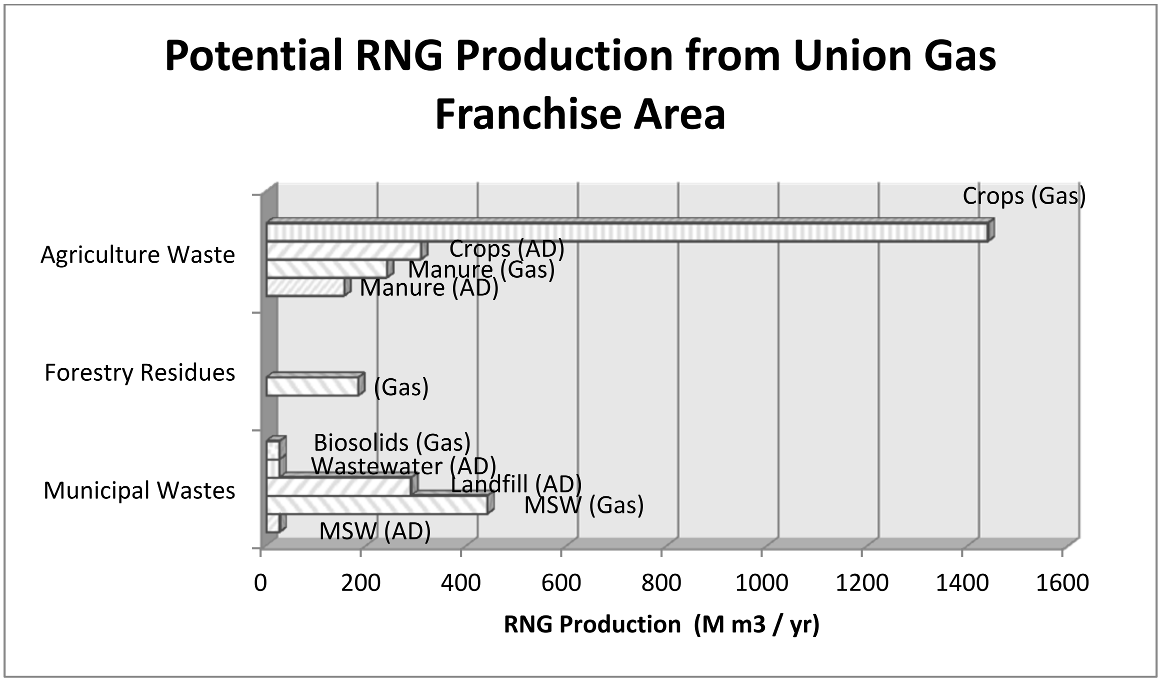


Figure 13. Potential RNG Production from Union Gas Franchise Area

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.

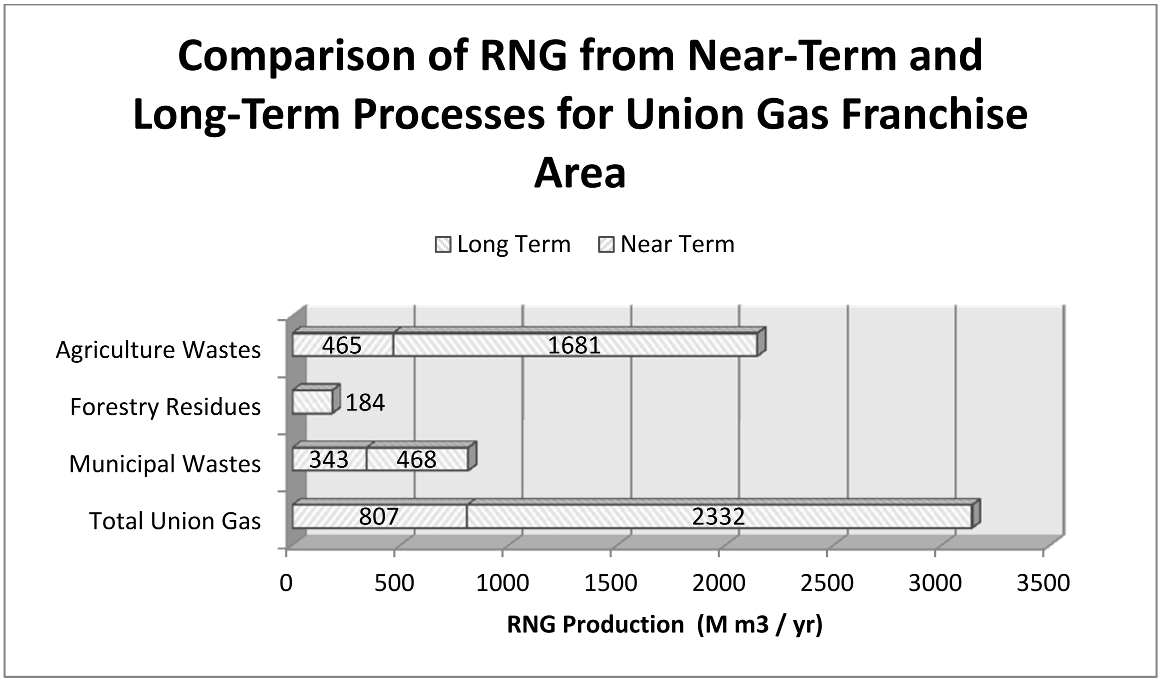


Figure 14. Comparison of RNG from Near-Term and Long-Term Processes for Union Gas Franchise Area.

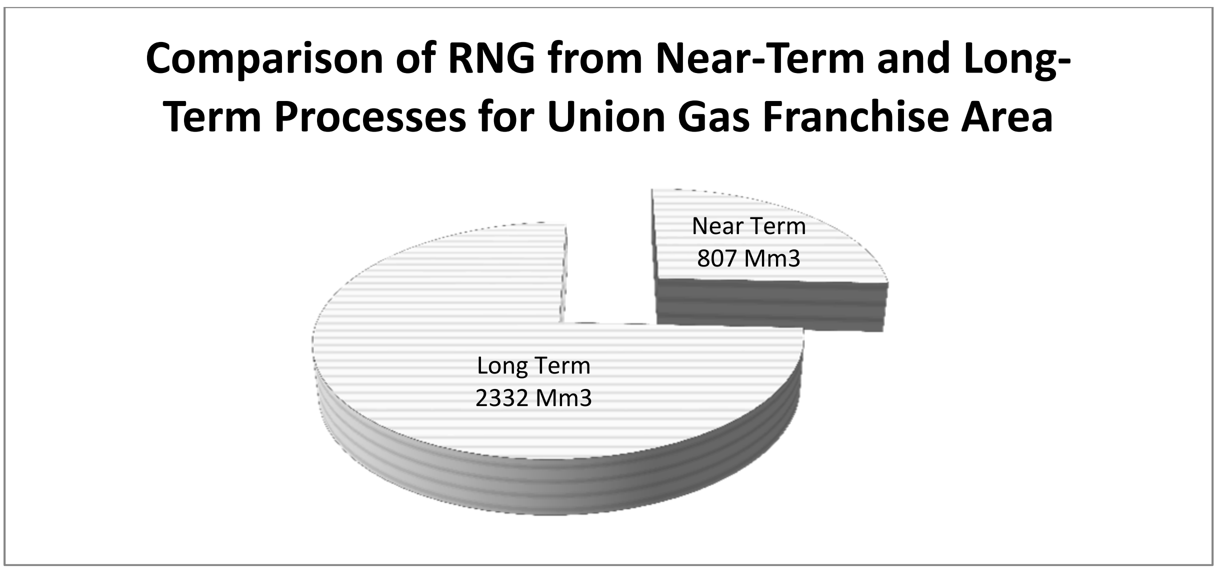


Figure 15. Comparison of RNG from Near-Term and Long-Term Processes for Union Gas Franchise Area.

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.

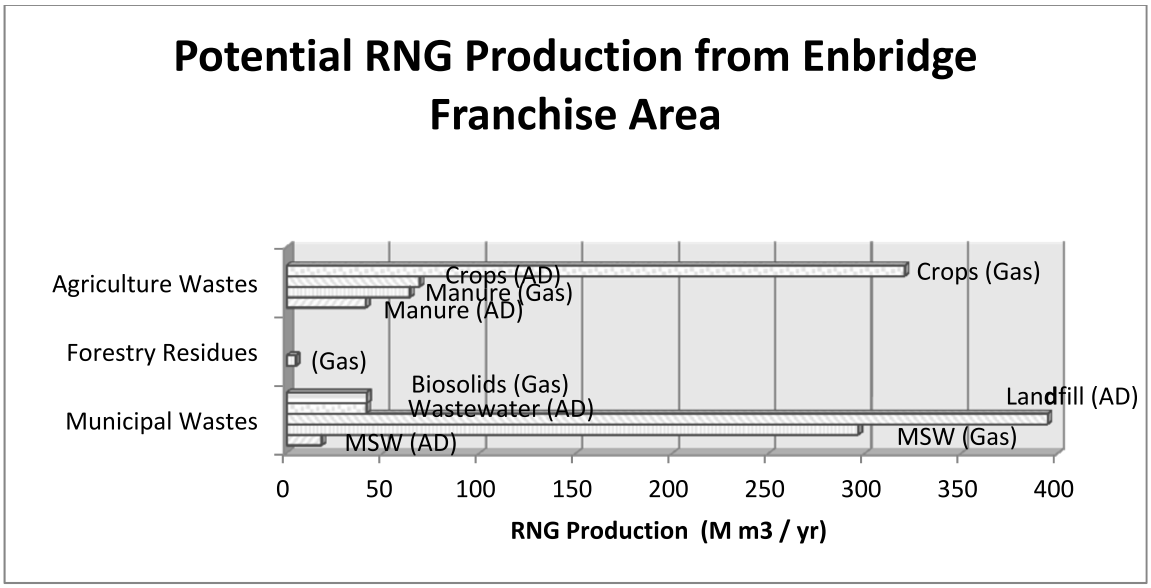


Figure 16. Potential RNG Production from Enbridge Franchise Area

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.

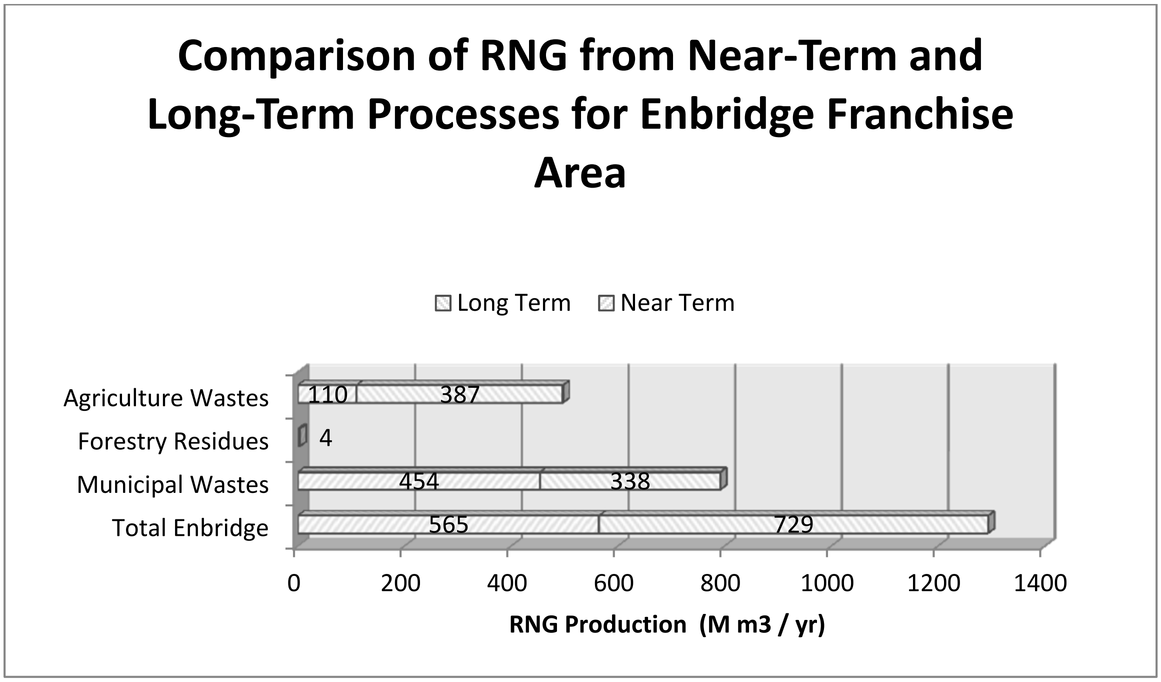


Figure 17. Comparison of RNG from Near-Term and Long-Term Processes for Enbridge Franchise Area.

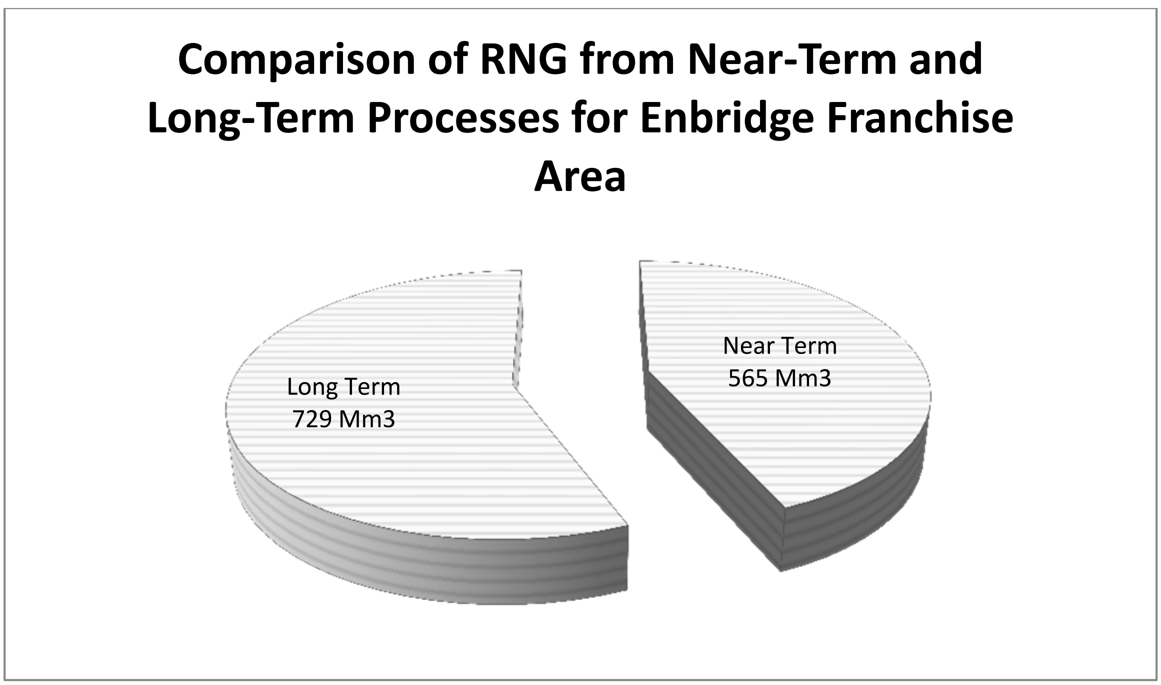


Figure 18. Comparison of RNG from Near-Term and Long-Term Processes for Enbridge Franchise Area.

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.

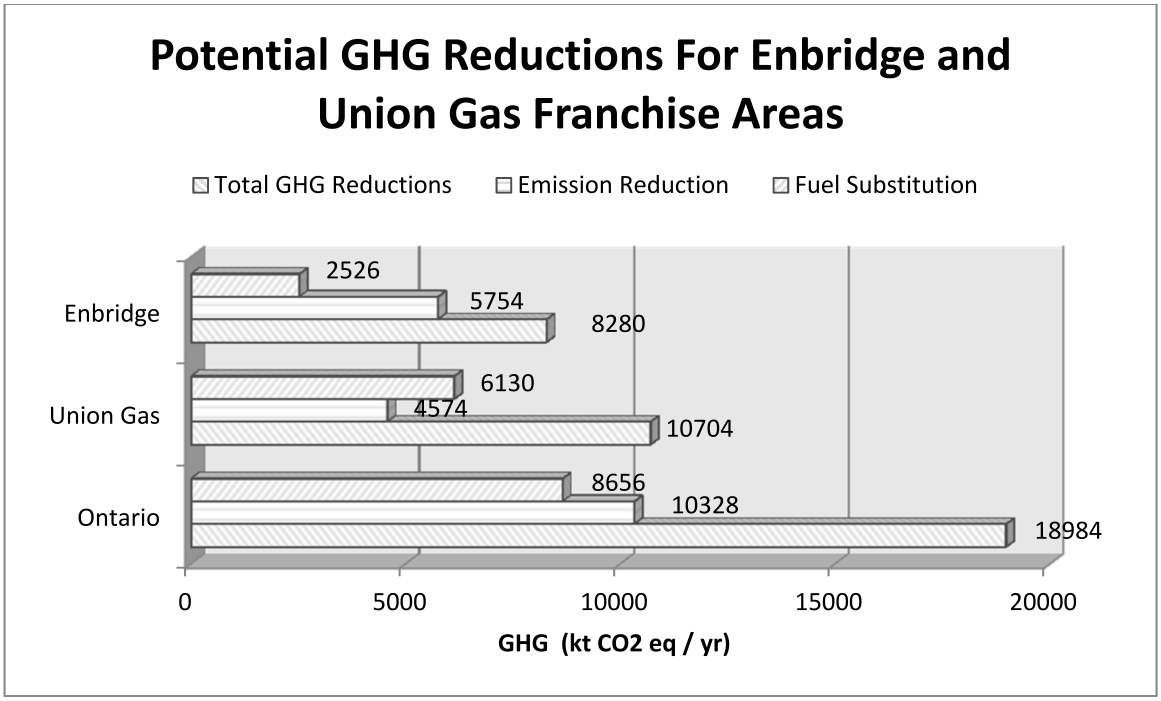


Figure 19. Potential GHG Reductions for Enbridge and Union Gas Franchise Areas

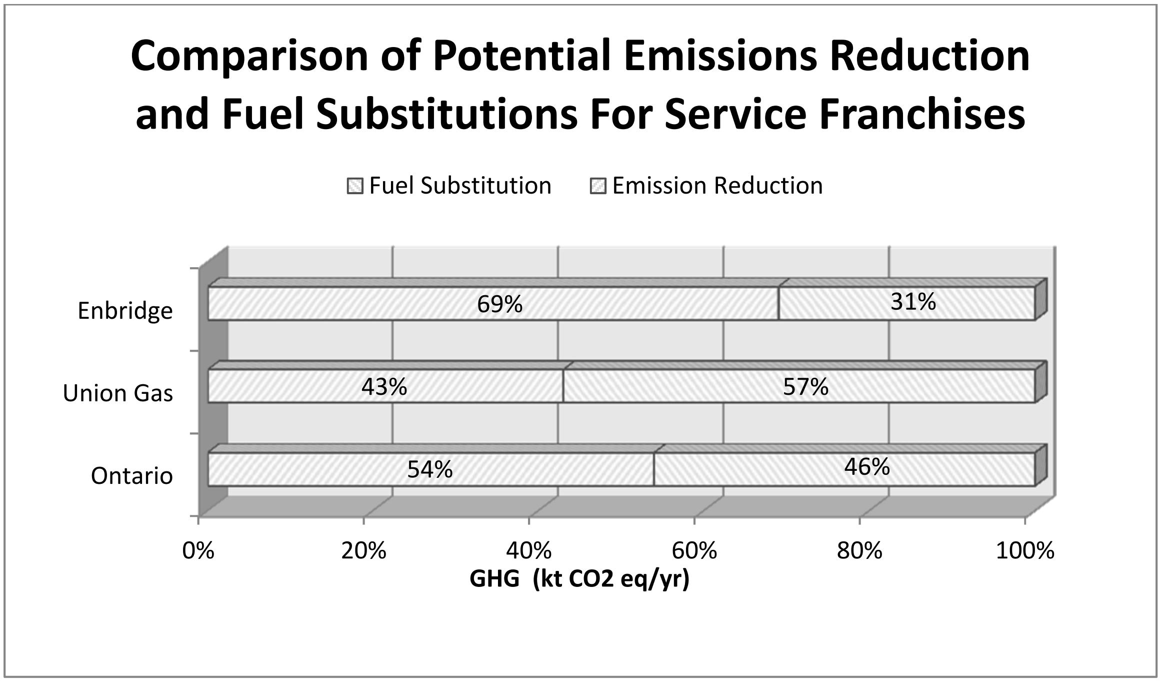


Figure 20. Comparison of Potential Emissions Reduction and Fuel Substitutions for Service Franchises.

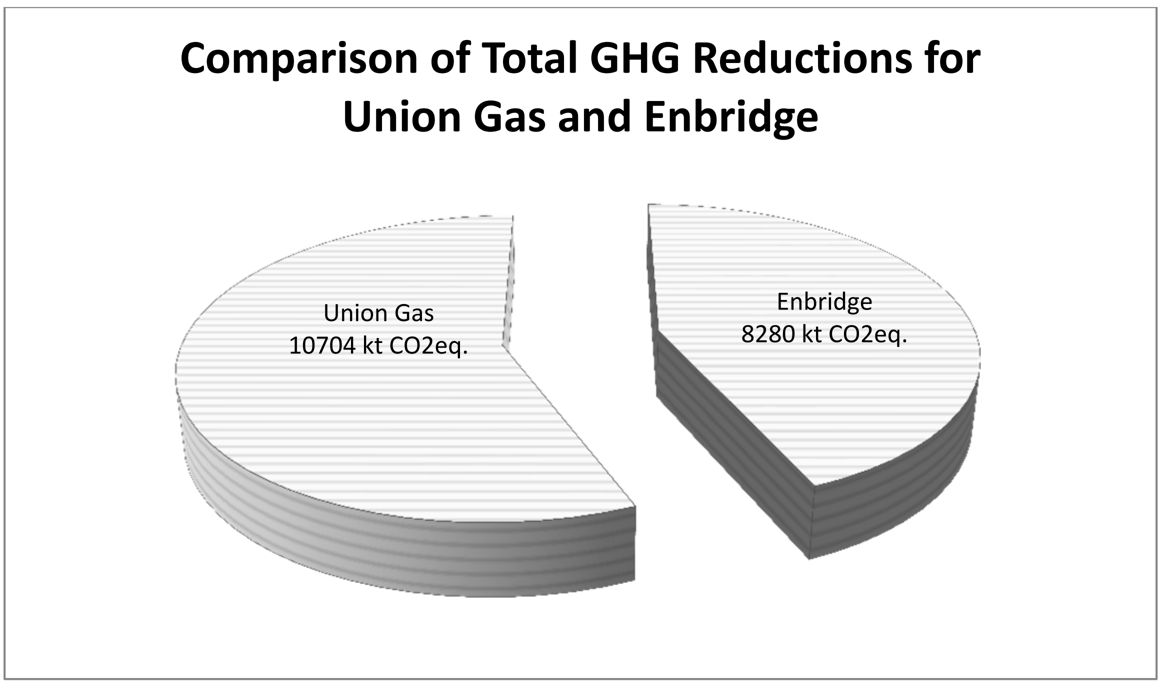


Figure 21. Comparison of Total GHG Reductions for Union Gas and Enbridge

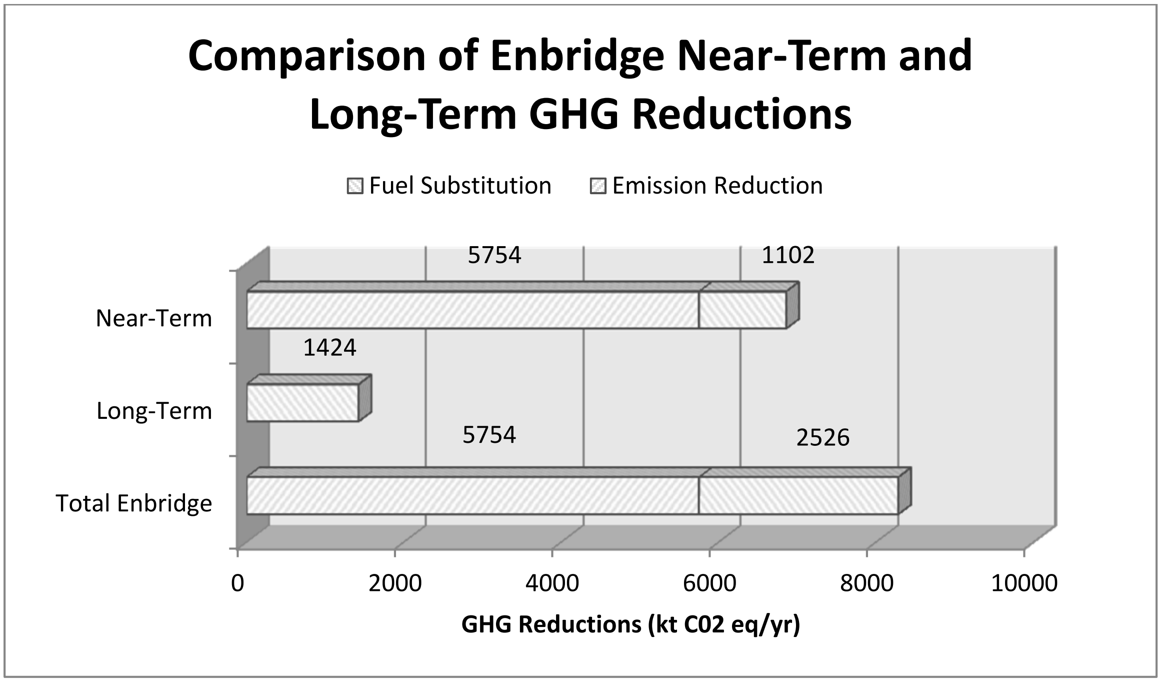


Figure 22. Comparison of Enbridge Near-Term and Long-Term GHG Reductions.

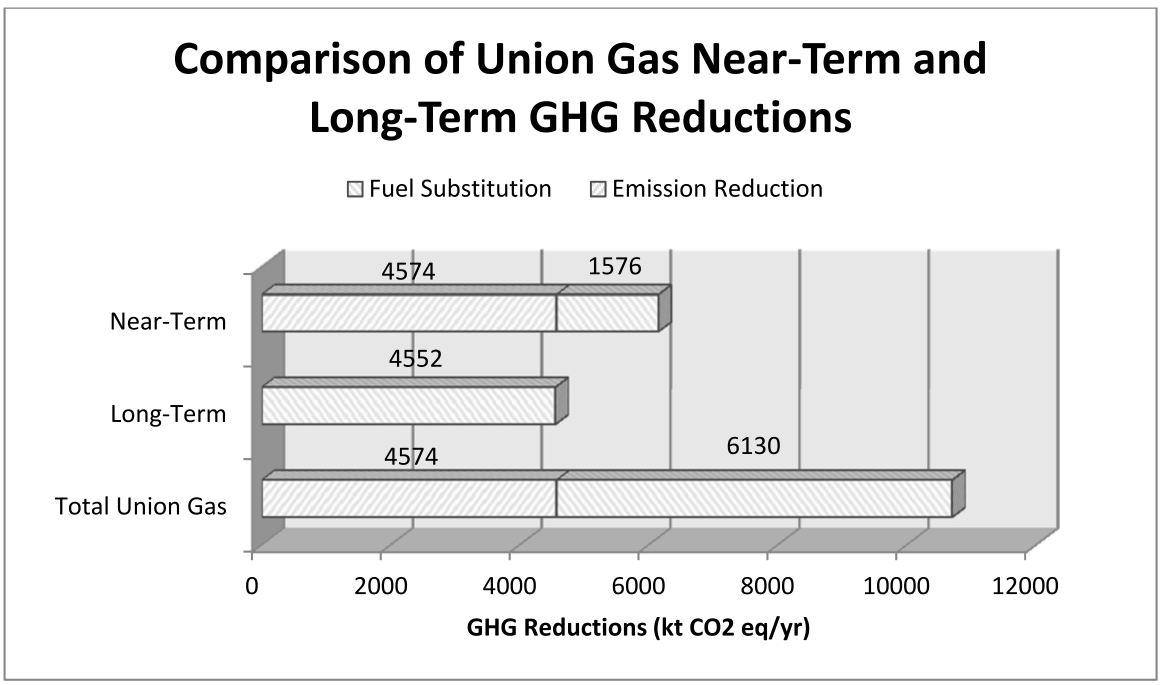


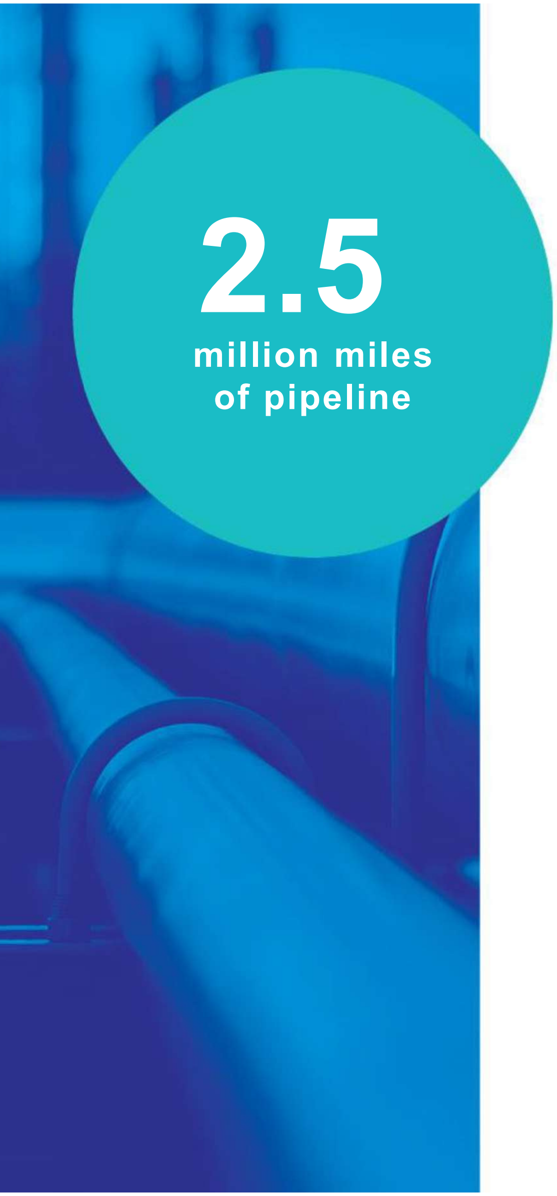
Figure 23. Comparison of Union Gas Near-Term and Long-Term GHG Reductions.

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.

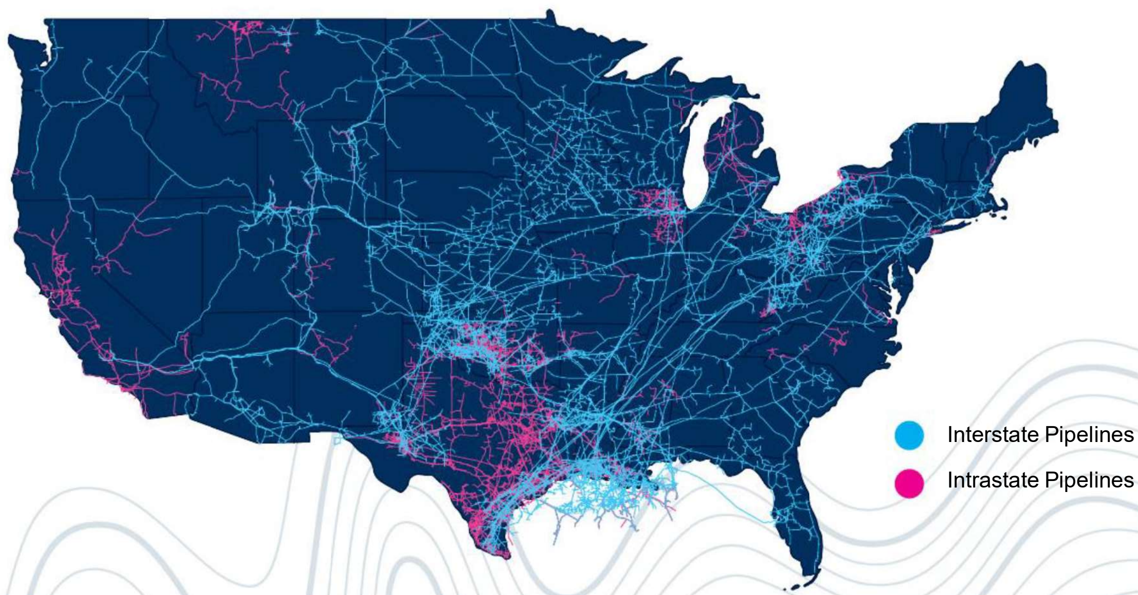
Gas Utility RNG Activities

Frank Canavan
State Legislative and Regulatory Analyst
December 5, 2019



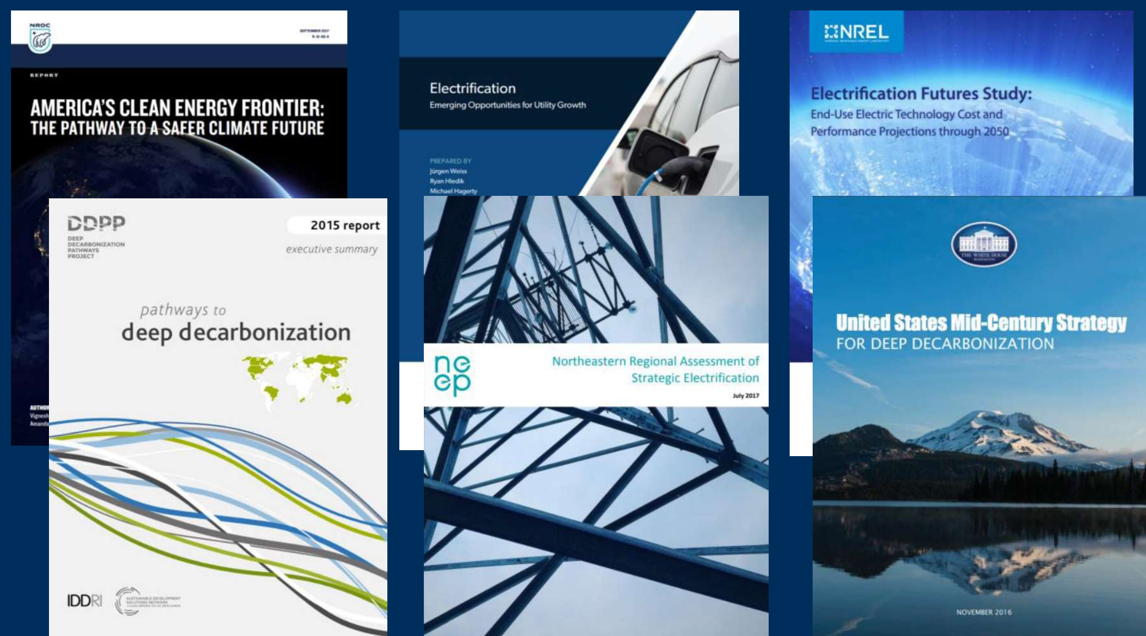
THE SAFEST WAY TO DELIVER ENERGY

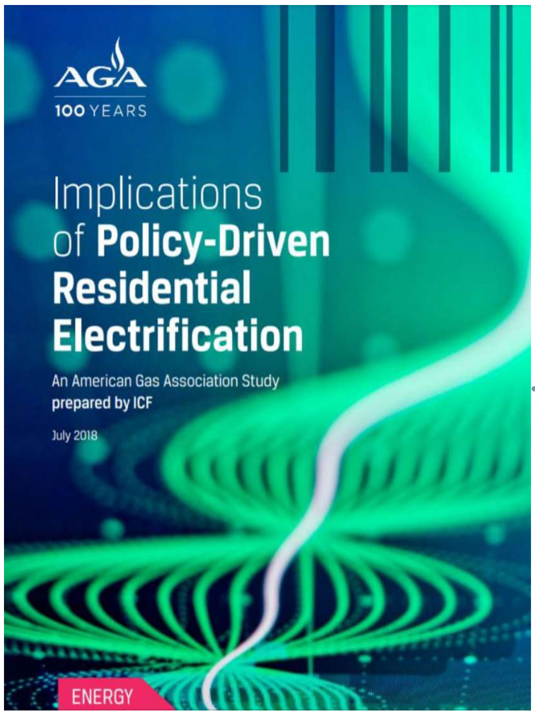
Natural gas is delivered to customers through a 2.5-million-mile underground pipeline system. This includes 2.2 million miles of local utility distribution pipelines and 300,000 miles of transmission pipelines that stretch across the country.



Proposals to reduce greenhouse gas emissions take many forms

Studies may assume electrification of building energy loads to be a pathway to decarbonization





Policy-Driven Electrification has the potential to be a very costly approach for a relatively small reduction in emissions.

$750–$910

Policy-Driven Electrification could be burdensome to customers and the economy. With average household energy-related costs increase of $750–$910 per year.

$400 Billion +

The electric sector could experience profound impacts and cost increases of more than $400 billion in generation capacity requirements and associated transmission system upgrades.

Natural gas technologies offer pathways to achieve our shared goal of reducing emissions while maintaining affordability, reliability and the quality of life that Americans enjoy.

American Gas Foundation
2019 Studies

Opportunities for Reducing GHG Emissions Through Emerging Natural Gas Direct-Use Technologies

Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment Study

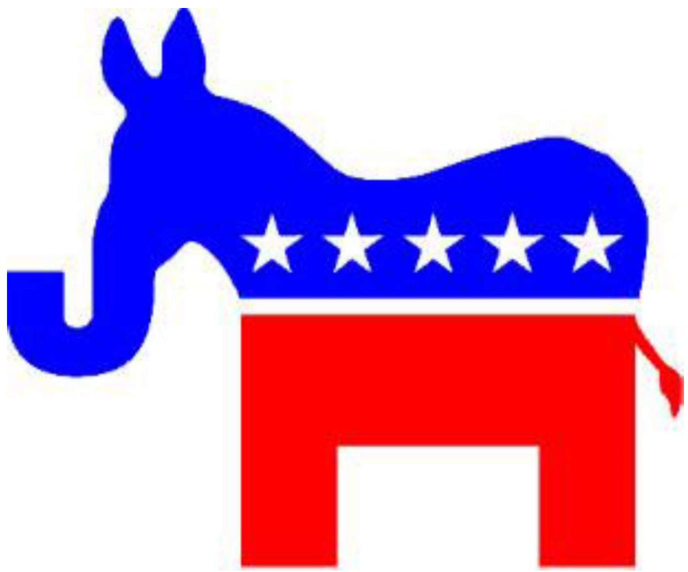
Renewable Natural Gas

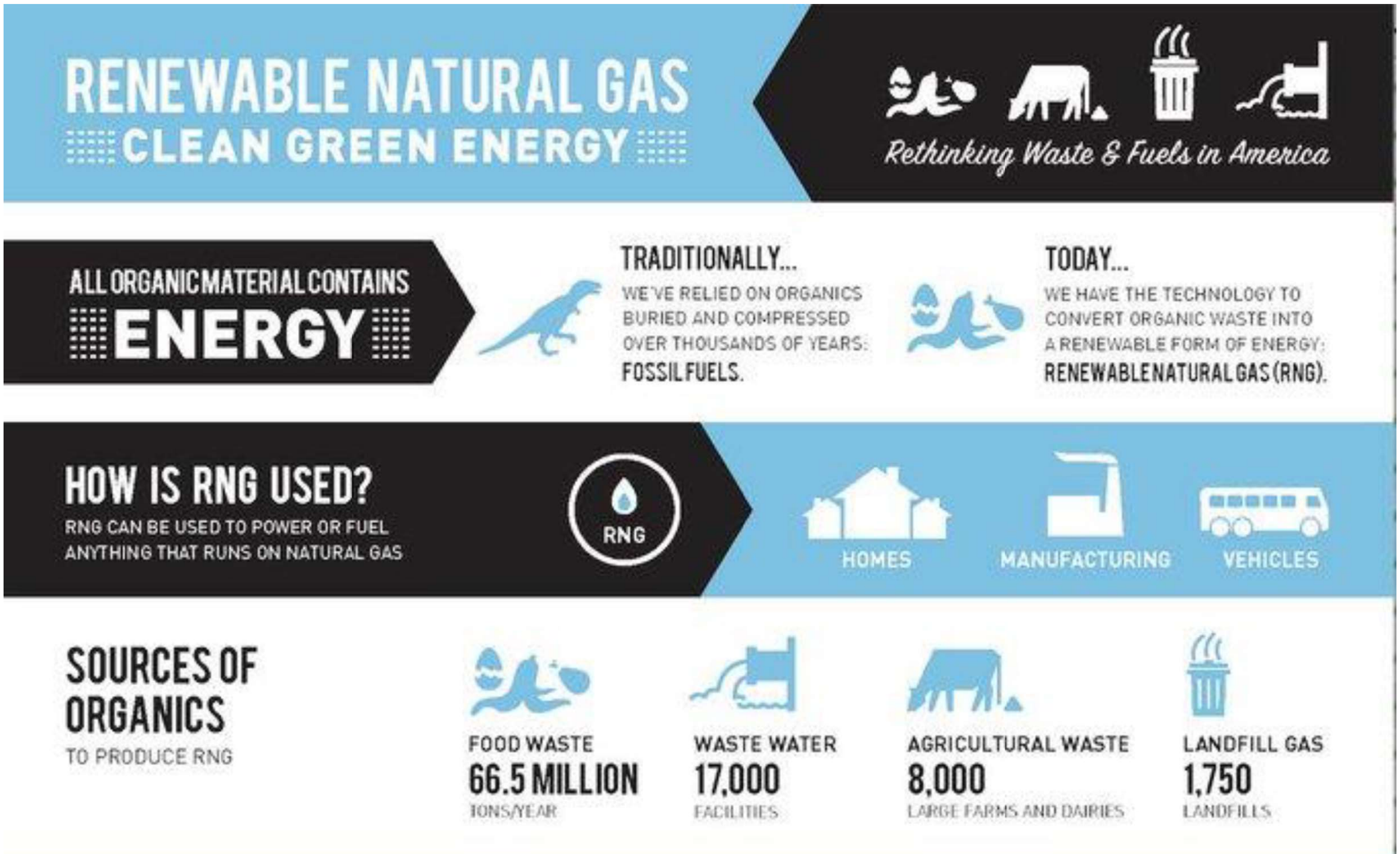
"Pipeline compatible gaseous fuel derived from biogenic or other renewable sources that has lower lifecycle CO_2e emissions than geological natural gas."

Examples include pipeline compatible gas derived from:

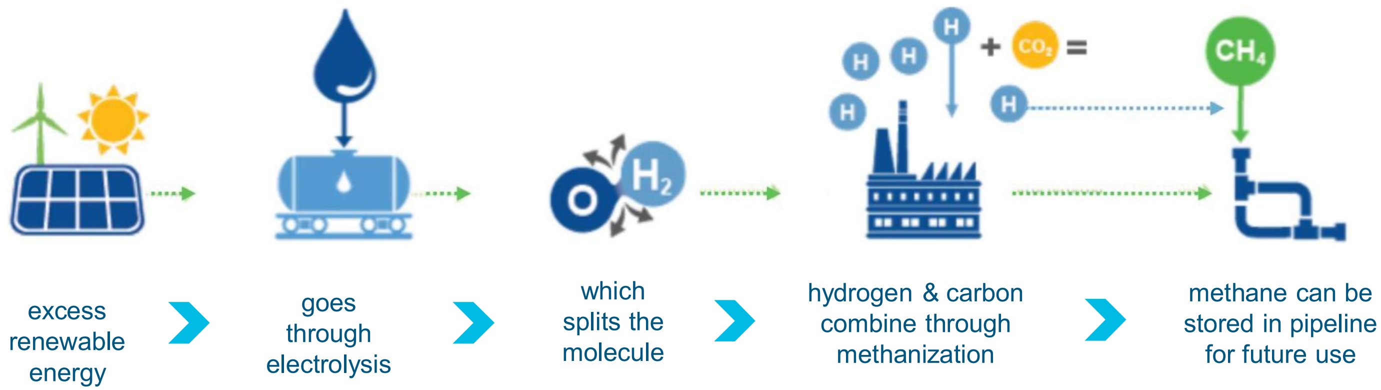
- Wastewater treatment plants
- Landfill gas
- Anaerobic digestion gas
- Power to gas from renewable electricity
- Syngas

RNG: Not a partisan issue!

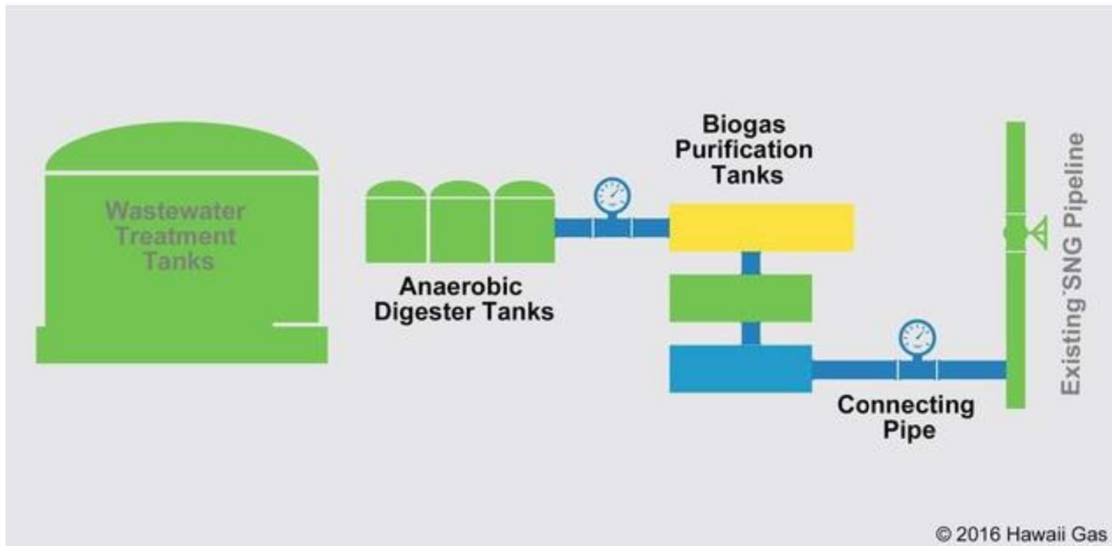



RENEWABLE NATURAL GAS
CLEAN GREEN ENERGY
Rethinking Waste & Fuels in America
ALL ORGANIC MATERIAL CONTAINS
ENERGY
TRADITIONALLY...
WE'VE RELIED ON ORGANICS BURIED AND COMPRESSED OVER THOUSANDS OF YEARS:
FOSSIL FUELS.
TODAY...
WE HAVE THE TECHNOLOGY TO CONVERT ORGANIC WASTE INTO A RENEWABLE FORM OF ENERGY:
RENEWABLE NATURAL GAS (RNG).
HOW IS RNG USED?
RNG CAN BE USED TO POWER OR FUEL ANYTHING THAT RUNS ON NATURAL GAS
RNG
HOMES
MANUFACTURING
VEHICLES
SOURCES OF ORGANICS
TO PRODUCE RNG
FOOD WASTE
66.5 MILLION
TONS/YEAR
WASTE WATER
17,000
FACILITIES
AGRICULTURAL WASTE
8,000
LARGE FARMS AND DAIRIES
LANDFILL GAS
1,750
LANDFILLS

POWER TO GAS



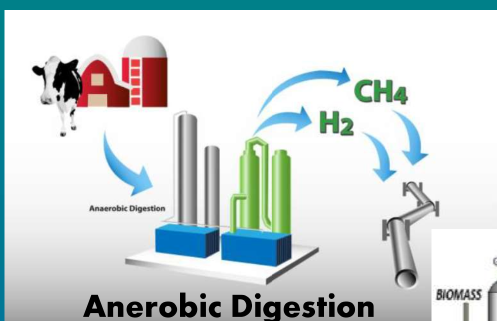
ANEROBIC DIGESTION



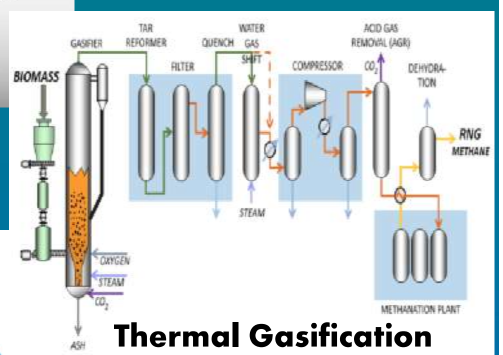
Study Objective

To characterize the technical and economic potential for Renewable Natural Gas (RNG) as a GHG emission reduction strategy and improve policy makers' understanding of the extent to which delivering RNG to all sectors of the economy can contribute to broader GHG emissions reduction goals.

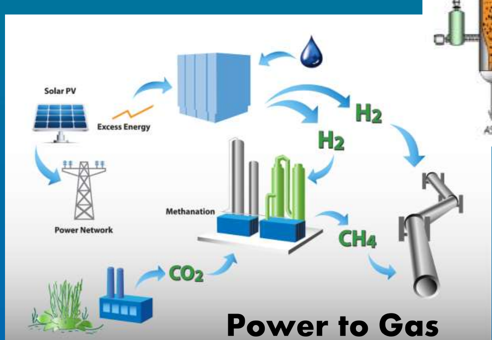
Renewable Natural Gas Study



Anerobic Digestion



Thermal Gasification

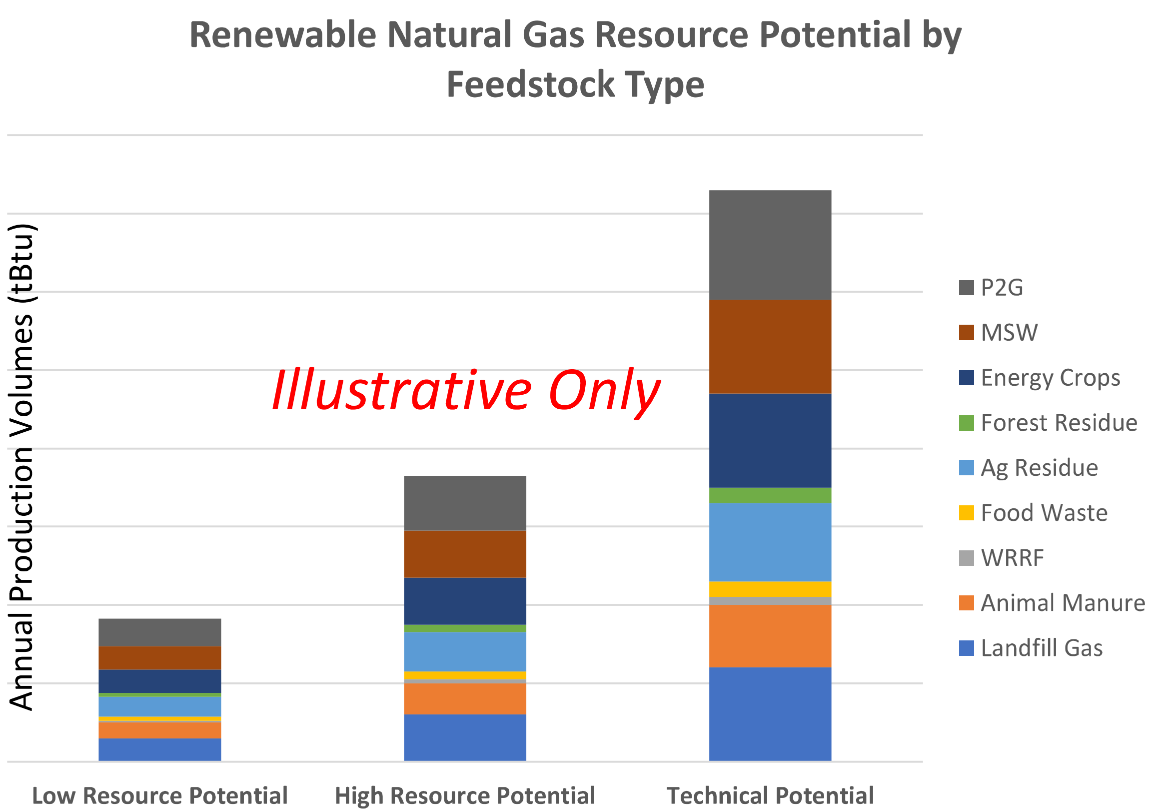


Power to Gas

Seeks to Answer the Following Questions

- How much RNG could be produced from various feedstocks and technologies?
- What is the GHG emission reduction potential?
- How much is it going to cost?
- Is the cost/ton of emissions reduction competitive with other carbon abatement options?

Modeling Two Scenarios



ICF developed methodologies to develop the production potential for each feedstock

Landfill Gas Example

LANDFILL METHANE OUTREACH PROGRAM

Open / close post-2000

Landfills 2,000+ → 1,500

	Resource Base	Low-High
Candidate Landfills	480	110-340
Existing LFG-to-Energy	620	180-320
LFG Collection	150	70-90
No LFG Collection	250	55-70

Assessment conducted at state-level, aggregated into US Census regions

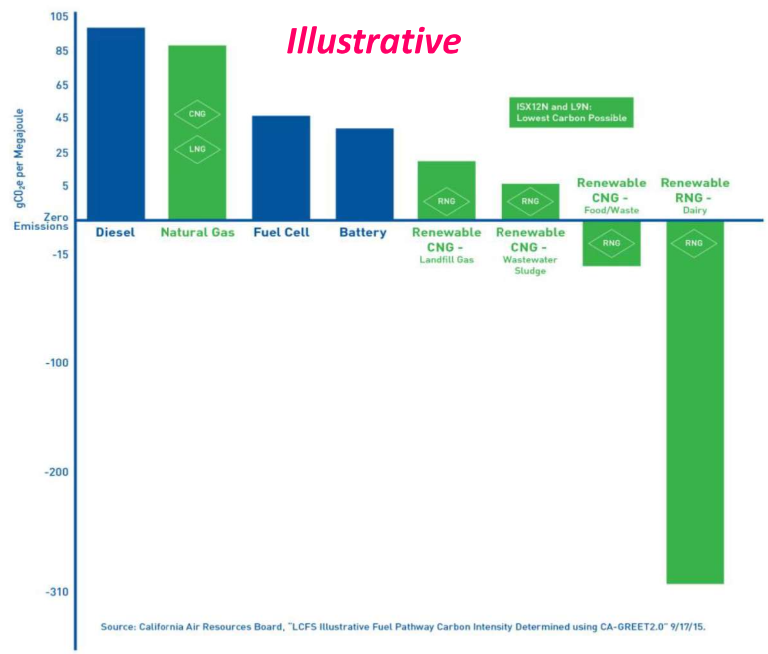
Emission Accounting Framework for RNG

Binary Framework

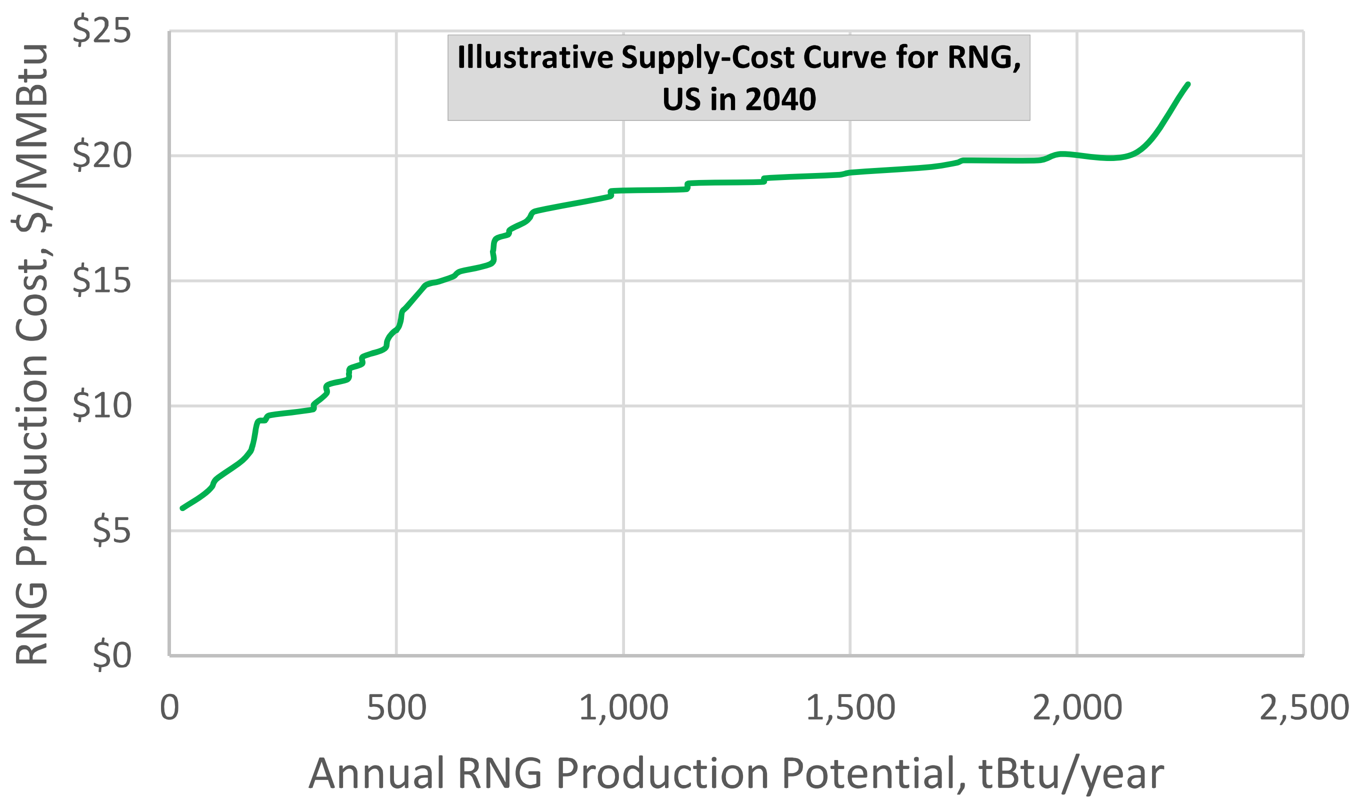
Geologic Natural Gas > 0

Renewable Natural Gas = 0

Lifecycle Emissions Framework



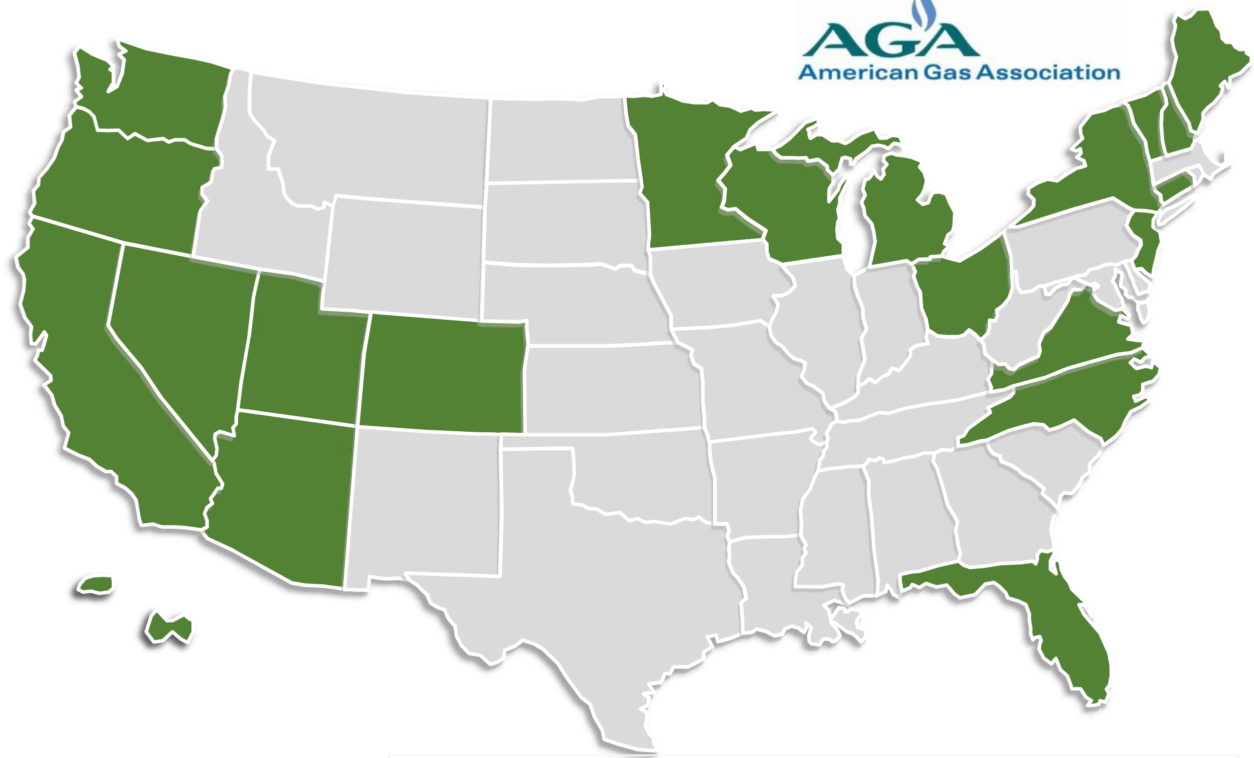
Supply Cost Curve by RNG Feedstock



Utility Programs

Renewable Natural Gas State Activity

AGA
American Gas Association



20 Bills have been introduced

16 Bills have become law

State Legislative Proposals

9 Natural Gas Utilities have begun developing or have implemented Voluntary Green Tariffs

Voluntary Programs

13 Natural Gas Utilities are engaged in RNG production projects

Utility Led RNG Projects

Activity in 21 states to promote the use of RNG in the residential or commercial sector through either legislative, regulatory, or utility led action.

*this data does not include RNG interconnection activity

RNG Legislation & Voluntary Programs

- NV SB 154 (2019)
- OH HB 166 (2019)
- OR SB 98 (2019)
- DTE Energy "BioGreen Gas"
- NW Natural "Smart Energy"
- Vermont Gas RNG program

NW Natural®

RNG as the next step

Manufactured gas for lighting and heat (1860s)

Network expands with arrival of Northwest pipeline (1950s)

Modernized system, decoupled rates, energy efficiency (2000s)

RNG and Renewable Hydrogen to Deeply Decarbonize (2010 and beyond)

Oregon SB98- New Opportunity

Passed in 2019 most aggressive RNG policy in the country

- Utility can purchase renewable natural gas and hydrogen for all customers as part of resource mix
- Enables the utility to play a role in developing RNG & make long term contracts for renewable supply
- Sets "voluntary targets" for RNG (to 30% by 2035) and a spending limit to protect customers – 5% of Revenue Requirement spent annually on incremental cost of RNG
- Rule making scheduled to complete in summer of 2020

OPUC RNG Rulemaking for SB 98

Docket AR 632 to produce rules by July 31, 2020

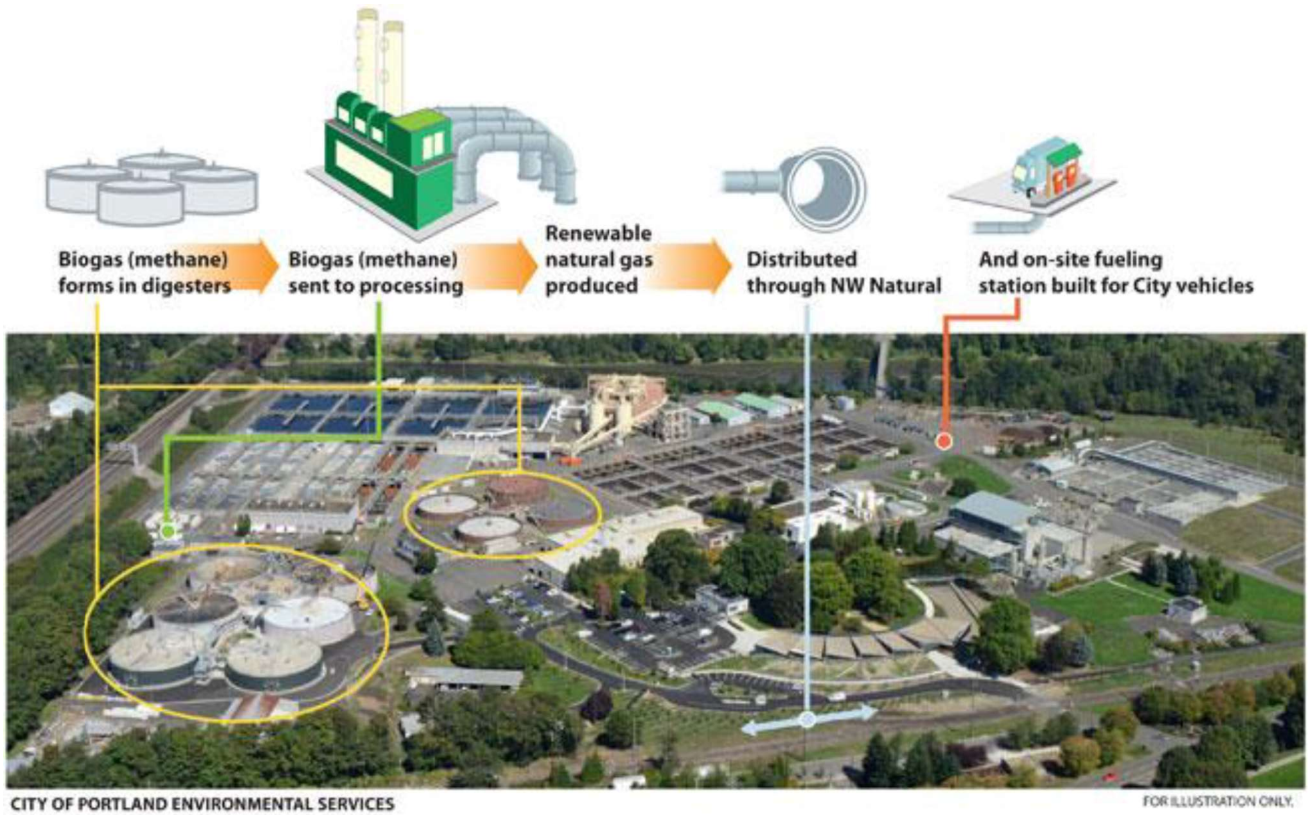
- RNG defined to include biogas and hydrogen derived from renewable energy sources
- Cost recovery mechanisms for utilities to recover qualified investments in the production of RNG and the procurement of RNG from third parties
- Impact of incremental costs for RNG capped at 5 percent; details of incremental cost to be determined. Separate investigation on NW Natural’s incremental cost methodology proposed in 2018 IRP
- Separate programs for Large (>200K customers) LDCs and Small LDCs

FROM WASTE TO RENEWABLES

Portland’s Wastewater Treatment Plant RNG Project

- City’s single largest climate action project
- 100% methane recovery
- 21,000 tons CO_2 saved annually
- Displaces diesel fuel in heavy-duty trucks
- Three-year payback
- Similar projects in the works elsewhere

Interconnection of RNG Projects



Research - Voice of the Customer

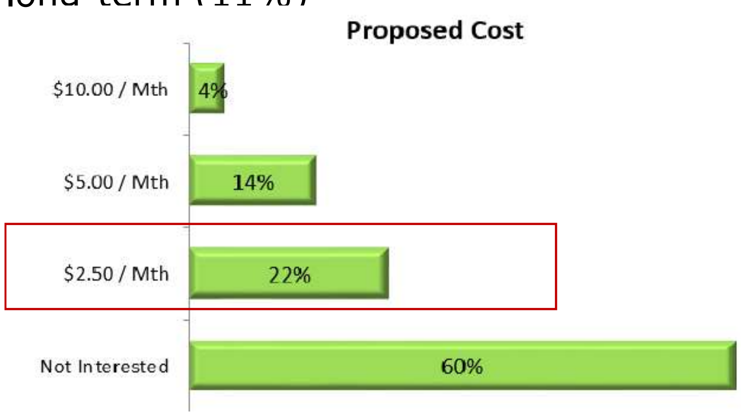
40% of respondents expressed interest in signing up for a Green Gas program. 22% would be willing to pay $2.50 / month

Reasons to Participate

- Help sustain the environment (28%)
- Use a resource already produce (20%)
- Support alternative energy initiatives in general (16%)
- Reduce emissions, pollutants and greenhouse gases (12%)
- Support alternative energy initiatives to help lower costs in the long-term (11%)

Reasons to Reject

- Don't want to or can't pay more / Bill too high already (46%)
- Need more information / better explanation of program (14%)



DTE

BioGreenGas Program – Program Mechanics

- For $2.50 / month, customers can elect to pay a renewable resource premium to support renewable energy development
- DTE purchases the renewable natural gas from a MI-based landfill. The natural gas is then sold back into the market for the current commodity natural gas cost
- The RNG program costs remain separate from DTE's Gas Supply purchases
- The cost differential reflects the premium paid for the environmental benefits of the landfill gas. This cost differential is then amortized over time across the customers enrolled in the program until additional RNG needs to be purchased
    - Ex):

    - $40K would be amortized over time (given 2,000 customers, $40K would support the program for 8 months)
- All RNG purchases and marketing costs funded out of existing O&M budget

DTE

BioGreenGas

Permanent Program Offering

- Established BioGreenGas as a permanent program
  - Pilot program resonated with DTE Gas customers' desire for a renewable natural gas offering
  - Post research results indicate customer acceptance, in addition to displaying a positive impact on DTE Energy overall customer satisfaction
  - Program dedication is reflected in low termination numbers

- Continue to source the RNG locally
  - Continue the foundation on which the program originated and demonstrate commitment to Michigan
  - Filing stipulates that RNG must be sourced from a Michigan-based landfill

- Expand the program offering
  - Maintain the residential product offering base of 2,000 customers
  - Add small commercial customers to the program

- Manage the manual enrollment process within Gas Sales & Marketing until IT constraints are lifted
  - Supports a slow growth strategy
  - Pre-specifications have been defined making the process repeatable, manageable and auditable

- Filed and received approval for permanent program in mid-2015

DTE

Program Development Timeline

2011	• Program Ideation and development
2012	• Pilot launched – pilot targets met in 130 days
2014	• Filed for extension to continue pilot while the permanent program was being developed, additional research conducted
2015	• Filed for and received approval for permanent program, expanded to business segment
2016	• New billing system launched; obstacles for marketing BioGreenGas. Program continues to which has sustained with organic growth and natural attrition
2017	• Conducted research to reaffirm customer perception of program. Research also indicated increased promotion and resources required to fully realize benefit.
2019	• Currently, 1,900 customers are enrolled in the BioGreenGas program which has sustained with organic growth and natural attrition. New program research design in progress. Potential refined program to be developed in 2020

VGS Renewable Natural Gas™

Vermont Gas Systems

- Voluntary RNG program began in 2017.

- Customers can choose to buy RNG in amounts equal to 10% ,25%, 50%, or 100% of their total monthly requirements at specified prices per Ccf as an “adder” or may elect to purchase a fixed amount per month of the environmental attributes associated with RNG.

- An average household enrolling in the VGS Renewable Natural Gas program at the 100% level will effectively nullify the corresponding carbon footprint associated with the customer’s direct use of natural gas.

- VGS has a target of eliminating all GHG emissions by 2050 through a combination of RNG and energy efficiency savings.

Goodrich Farm Project

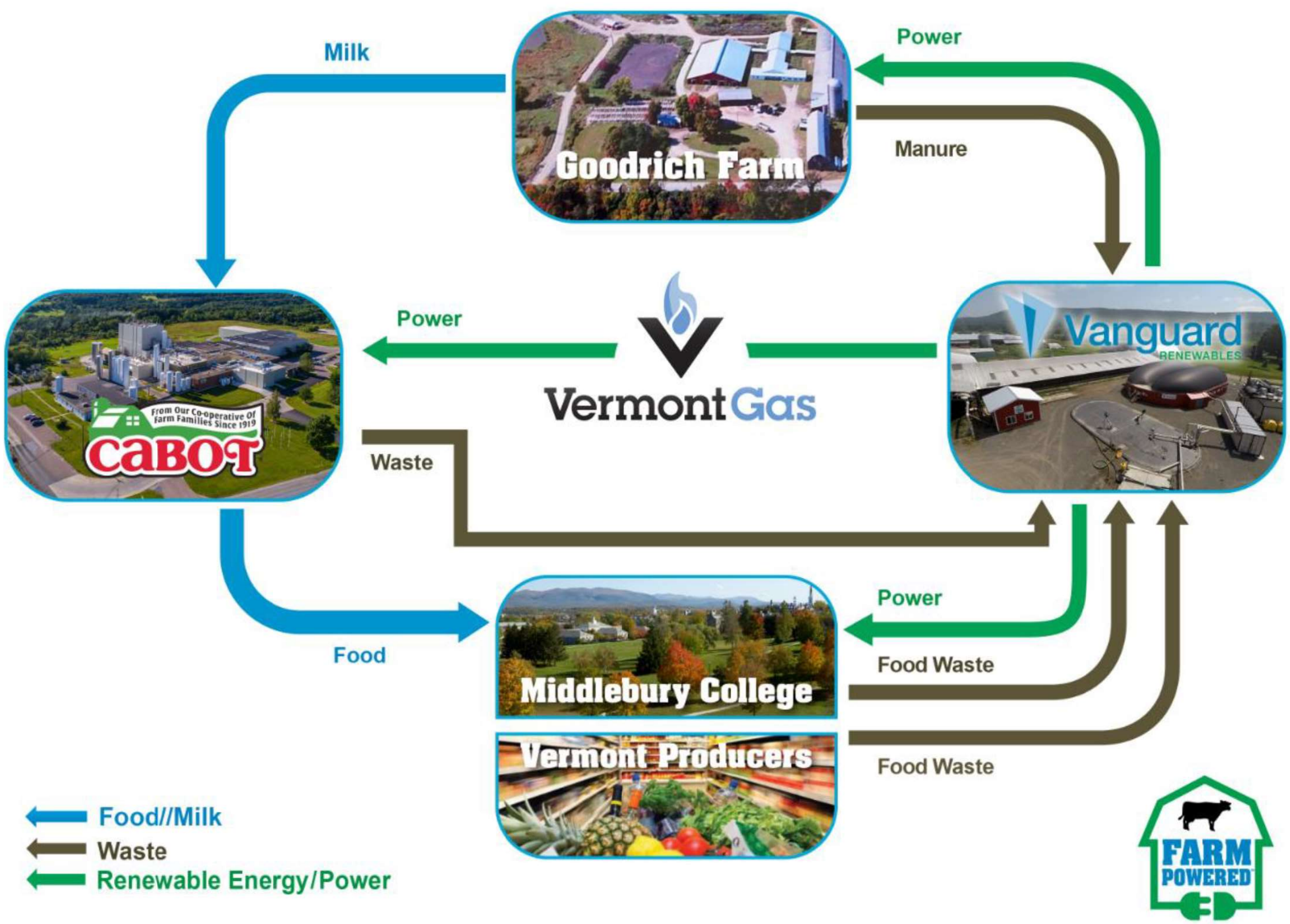
- Joint venture project between VGS, Vanguard Renewables, and Middlebury College

- Anaerobic digestion facility that will combine cow manure and food waste to produce RNG delivered by pipeline to Middlebury College.

- When completed in 2020, it will be the largest anerobic digestion facility plant east of the Mississippi River and is expected to produce 180 000 million cubic feet (Mcf) per year.

- Project will allow VGS to utilize in-state sources of RNG. Estimated capacity to process 100 tons of manure and 180 tons of organic food waste per day.
  - Current RNG supplied by EBI Landfill in Quebec

- The project will enable food producers and users in Vermont to comply with Act 148, Vermont's Universal Recycling Law, that bans all food waste from landfills and goes into effect in 2020.


Milk
Goodrich Farm
Power
Manure
Power
Vermont Gas
Vanguard
RENEWABLES
From Our Co-operative Of Farm Families Since 1919
CABOT
Waste
Power
Food
Middlebury College
Food Waste
Vermont Producers
Food Waste
Food//Milk
Waste
Renewable Energy/Power
FARM
POWERED

AGA
American Gas Association

Questions?

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Yale Environment 360

A manure and food waste-to-energy facility at Bar-Way Farm in Deerfield, Massachusetts. VANGUARD RENEWABLES

Could Renewable Natural Gas Be the Next Big Thing in Green Energy?

For decades, small-scale biogas systems have collected methane from landfills, sewage plants, and farms. Now, in Europe and the U.S., the growth of this renewable form of natural gas is taking off as businesses capture large amounts of methane from manure, food waste, and other sources.

BY JONATHAN MINGLE • JULY 25, 2019

In the next few weeks, construction crews will begin building an anaerobic digester on the Goodrich Family Farm in western Vermont that will transform cow manure and locally sourced food waste into renewable natural gas (RNG), to be sent via pipeline to nearby Middlebury College and other customers willing to pay a premium for low-carbon energy.

For the developer, Vanguard Renewables, the project represents both a departure and a strategic bet. The firm already owns and operates five farm-based biogas systems in Massachusetts; each generates electricity on site that is sent to the grid and sold under the state's net-metering law. The Vermont project, however, is Vanguard's first foray into producing RNG – biogas that is refined, injected into natural gas pipelines as nearly pure methane, and then burned to make electricity, heat homes, or fuel vehicles.

"Producing RNG for pipeline injection and vehicle fueling is the evolution of where everything is going" in the biogas sector, says John Hanselman, Vanguard's CEO.

Biogas has been around for a long time in the United States, mainly in the form of rudimentary systems that either capture methane from landfills and sewage treatment plants and use it to produce small amounts of electricity, or aging digesters at dairy operations that might power a local farm and send some surplus power to the grid. But those are fast becoming outdated and out-produced by a new wave of large-scale renewable natural gas projects that are springing up around the country. These ventures are tapping into heretofore unexploited sources of energy: some are capturing the vast amounts of methane generated by manure from some of the 2,300 hog farms that dot eastern North Carolina; some are building biodigesters to turn clusters of large California dairy farms into energy hubs; and some are seeking to divert food waste from landfills and transform it into vehicle and heating fuels.

Biogas systems could produce enough renewable energy to power 3 million homes in the U.S.

Renewable natural gas is reaching a tipping point for several reasons: An increasing number of third-party operators like Vanguard are relieving farmers and landfills of the burden of running their own energy systems and are introducing more sophisticated technologies to capture methane and pump it directly into pipelines. Some states, including California, are passing laws requiring the development of renewable natural gas. And utilities across the country are starting to support these new initiatives, as evidenced by the new partnership between Dominion Energy and Smithfield Farms – the world's largest pork producer – to develop new hog waste biogas projects. For proponents, the ultimate goal is to replace a significant portion of the fossil-derived natural gas streaming through U.S. pipelines with pure methane generated by human garbage and animal and agricultural waste.

“If you can recover energy before sending what remains back to the soil, that’s a great thing,” said Nora Goldstein, the longtime editor of BioCycle Magazine, which has covered the organics recycling and anaerobic digestion industries for decades. “You look at all those benefits and say, ‘Why aren’t more people doing this?’ The key is you need to do it correctly.”

The untapped potential – especially of the billions of gallons of animal manure and millions of tons of food waste generated each year in the U.S. – is immense. According to a 2014 “Biogas Opportunities Roadmap” report produced by the U.S. Environmental Protection Agency, the Department of Agriculture, and the Department of Energy, the U.S. could support at least 13,000 biogas facilities, fed by manure, landfill gas, and biosolids from sewage treatment plants. Those new systems could produce 654 billion cubic feet of biogas per year – enough renewable energy to power 3 million homes. And a study by the World Resources Institute estimated that the 50 million tons of organic waste sent to landfills or incinerated every year in the U.S has the energy content of 6 billion gallons of diesel fuel, 15 percent of all diesel consumed by heavy-duty trucks and buses.

A truck delivers food waste to an anaerobic digester at a Massachusetts farm. VANGUARD RENEWABLES

Experts say that the growing utilization of biogas could help lower greenhouse gas emissions from some of the toughest sectors to decarbonize – transportation, industry, and heating buildings – even as it reduces heat-trapping methane emissions, keeps organic waste out of landfills, and prevents manure runoff into rivers and water supplies. Through anaerobic digestion, biogas can be made from any organic material – food scraps, agricultural residues, even the sludge left over from brewing beer. These materials are fed as a slurry into tanks where microbes feast on them in the absence of oxygen, destroying pathogens, producing methane and other gases, and leaving a nutrient-rich fertilizer as a byproduct.

In the field of renewable natural gas, the U.S. is playing catch up with Europe, which has more than 17,400 biogas plants and accounts for two-thirds of the world's 15 gigawatts of biogas electricity capacity. Denmark alone, a country of 5.8 million people, has more than 160 biogas systems. For a period last summer, 18 percent of the gas consumed in Denmark came from RNG produced by its anaerobic digesters. Flush with their success, Danish bioenergy firms estimate it will be feasible to fully replace the country's natural gas with renewable natural gas within 20 years.

The former manager of the EPA's anaerobic digestion programs, Chris Voell, was so impressed with Denmark's biogas operations – which are highly engineered to digest a mix of household food scraps, residuals from food processing businesses, and livestock manure – that he now works for the Danish Trade Council to introduce Danish digester technology and business models to the U.S market.

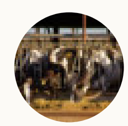
As with most climate initiatives, California is leading biogas efforts in the U.S. The state's Low Carbon Fuel Standard (LCFS) – which provides incentives for fuel producers to increase the amount of low-carbon or renewable fuels they supply and sell – is a key component of the state's ambitious climate plan and has catalyzed the rapid growth of a new, lucrative market for RNG as a vehicle fuel.

A growing crop of specialized firms builds, owns, and operates anaerobic digesters in the U.S.

Companies like Maas Energy Works and California Bioenergy have responded to these incentives by installing digesters at California's dairy farms at a rapid clip. Maas has built 17 so far, with 12 more under construction and 32 others in development, according to its website. Both companies are racing to take advantage of valuable LCFS incentives.

And both are among a growing crop of specialized, investor-backed firms that build, own, and operate anaerobic digesters in the U.S. "With every day the industry is gaining more credibility," Voell says. "We're seeing more professional third-party companies. And in order to see this scale, it takes those professionals to come in and build 10, 20, 50 projects, and access a lot of equity investors. They want a portfolio of projects to invest in, not just one."

In North Carolina, the abundant feedstock is hog manure. And the latest entrant in the RNG race is Smithfield, the world's biggest grower of hogs. North Carolina is the second-largest pork-producing state (after Iowa). Each day, more than 2,000 of its hog farms flush manure from 9 million pigs into vast lagoons, which emit equally vast quantities of methane. Ninety percent of those farms are contract growers for Smithfield.



ALSO ON YALE E360

How eating seaweed can help cows to belch less methane. Read more.

Late last year, Smithfield launched a joint venture, Align RNG, with a Virginia-based utility, Dominion Energy, to invest $250 million in covering lagoons and installing anaerobic digesters at nearly all of its hog finishing farms in North Carolina, Utah, and Missouri over the next 10 years. Construction is already underway on four projects that will produce enough RNG to power 14,000 homes and businesses.

A covered lagoon manure digester on Van Warmerdam Dairy in Galt, California. MAAS ENERGY WORKS

These systems will all be modeled on Optima KV, a biogas project in Kenansville, North Carolina, in the heart of hog country. Last year, Optima KV became the first project in the state to produce and inject RNG into an existing natural gas pipeline.

The factors that made Optima KV possible – along with the waste from 60,000 pigs on five nearby farms, and a centralized system to clean and upgrade the gas – include a state renewable energy portfolio standard law signed in 2007. That law contained a requirement that utilities source at least 0.2 percent of their electricity from swine and poultry waste by 2020. That mandate helped push Duke Energy, one of the biggest utilities in the U.S., to sign a 15-year agreement to purchase 80,000 million BTUs of RNG from Optima KV. That biogas will directly displace the use of fossil natural gas and generate 11,000 megawatt-hours of power in two of Duke's power plants.

Vanguard's new operation in Vermont represents an alternative model for scaling up RNG production. The company's digesters are more complex and expensive – engineered to produce a consistent output of gas even as feedstocks and other conditions change – than the systems being built in California. The California systems basically cover huge dairy waste lagoons with plastic membranes and then extract, refine, and pipe the gas to customers.

"We take a more high-tech approach primarily because we need to produce a lot more gas from a much smaller footprint," Hanselman says. "We don't have the luxury of a 10,000-cow dairy."

RNG has flourished in Europe because of generous subsidy programs that are lacking in the U.S.

Along with the daily stream of 100 tons of manure from the Goodrich farm's 900 cows, and 165 tons of food waste, a number of factors have come together to make Vanguard's Vermont project possible. In Middlebury College, Vanguard found a large customer eager to slash its carbon footprint. A new law about to take effect in Vermont will ban food waste from landfills starting in 2020, forcing grocery stores and food processors to find new places to send their waste.

And Goodrich Farm will get free heat, monthly lease payments for hosting the system, and bedding for its cows from the leftover digested solids – cost savings that can offer a lifeline for dairy farmers in a period of disastrously low milk prices.

Hanselman, Vanguard's CEO, says that a key element to expanding RNG is taking the burden of running the system off of farmers. Hanselman encountered many irate farmers who had negative experiences with a previous generation of digesters that had been sold to them as a low-maintenance, low-cost solution to their nutrient

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management problems. In fact, digesters are finicky machines, sensitive to changes in temperature and the variability of organic material in feedstocks. Says Hanselman, "We tell our farmers, 'Your job is to make milk, healthy cows, and take care of your fields and soils. Let us run these machines.'"

RNG has flourished in Europe in part because of generous subsidy programs; such comprehensive policies are lacking on the federal level in the U.S., which has a chaotic patchwork of regional and state markets, utilities, incentives, and policies. But Hanselman and others foresee that in the next several years, more states will mandate renewable natural gas production, further strengthening the fledgling biogas market.

An open house showcasing a renewable natural gas system at Philip Verwey Farms in Hanford, California. MAAS ENERGY WORKS

"It feels extremely similar to solar," says Hanselman, who used to run a solar company. "We are in the early days of RNG. Everyone will be running from program to program trying to figure out which states are beneficial, and how to best get RNG into the marketplace."

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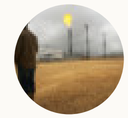
Market forces alone, however, won't be enough to usher in a biogas revolution. The single policy that could supercharge the growth of biogas and RNG in the U.S., most industry observers and insiders agree, is a federally legislated price on carbon. But given that a carbon tax or comprehensive climate bill aren't likely to emerge any time soon under the current administration, Hanselman says the next best thing the federal government could do is reinstate the investment tax credit for digester systems, which lapsed in 2016.

Despite these challenges, Voell thinks there is now enough momentum to see biogas finally gain widespread traction as a renewable energy source in the U.S.

"I'm more encouraged now more than ever, because I'm actually seeing some projects getting built," he says. "The states are stepping up with policies. And we're seeing a revolution now where gas utilities are coming on board. Utilities wield a lot of power. If they decide RNG is something they'd like to see more of, then we'll start to see the needle move more on the policy front."



ALSO ON YALE E360

How climate activists failed to make clear the problem with natural gas. Read Bill McKibben's opinion piece.

Jonathan Mingle is a freelance journalist who focuses on the environment, climate, and development issues. His work has appeared in *The New York Times, Slate*, *The Boston Globe*, and other publications. He lives in Vermont. **MORE →**

Ontario farmers seeing revenue opportunity in biogas digesters

Renewable natural gas contracts are making new methane capture projects profitable again

By John Greig
Editor

Published: December 3, 2019
News

Reading Time: 6 minutes

Reading Time: 6 minutes

Renewable natural gas produced in biogas digesters is emerging as an opportunity for Ontario farmers to capture revenue from waste.

Natural gas utilities in British Columbia and Quebec have requested proposals to supply scrubbed methane from biogas digesters for customers willing to pay more for natural gas with a lower carbon footprint.

> ***Why it matters***: With 38 on-farm methane digesters in operation in Ontario, the province is well-placed to take advantage of this emerging opportunity

Stanton Bros. Ltd. of Ilderton has applied to expand the biodigester on its dairy farm so that it will be able to continue to produce electricity and have the capacity to also put methane gas into the natural gas grid.

The farm currently powers three 250 kw generators from a biodigester that uses the manure from its large dairy herd along with food waste. Laurie Stanton says they have excess gas that has to be flared off and "that always bothers me to see dollars going up in smoke."

They use the digested solids as bedding and spread some on fields.

Their current plan is to double their digester capacity with the new digester, feeding natural gas into the line that goes past their farm.

The technology and ability to produce natural gas from captured methane isn't new, says Jennifer Green of the Canadian Biogas Association. It was there when methane digesters were built to burn the gas in generators to produce electricity in response to the province's Feed In Tariff program. That's where the market pull was at that point, says Green.

The cleaning system and generators for the existing biogas digester at the Stanton farm. photo: John Greig

Now, with little new in the way of renewable electricity projects following the cancellation of the Green Energy Act in Ontario, the pull for renewable natural gas is coming from outside the province.

Similar to the 20-year-contracts created in Ontario to drive solar, wind and biogas electricity generation, natural gas utilities Fortis B.C. and Energir in Quebec are offering long-term contracts for renewable natural gas at rates attractive enough to create interest from farmers, composting facilities, landfills and municipalities.

Enbridge Gas, the largest natural gas provider in Ontario, is also in the process of applying to the Ontario regulator to offer its own contracts for renewable natural gas, says Rob Dysiewicz, Enbridge Gas's business development manager for renewable natural gas. The provincial government has announced changes that encourage renewable natural gas, but the details aren't yet completely known.

Carbon credit market driving growth

The opportunity to sell higher-priced renewable natural gas is being driven by carbon trading markets and carbon levies across the country and the United States. Companies and individuals looking to offset their carbon usage are being pushed by levies on carbon to look at processes that are carbon neutral.

Dairy farmers are the main users of biogas digester on farms. Composting facilities, landfill sites and municipalities also have them. photo: John Greig

Dysiewicz says there are several reasons that make on-farm biogas efficient and cost effective.

They include:

- There are fewer permit requirements for farmers than for industrial or municipal biogas digesters. "The least expensive way to get an anaerobic digester built is in farming," he said.

- The solids left over from the digestion process are an excellent fertilizer.
- Farms with digesters can take local organic waste, which reduces the amount of waste going to the landfill and can save companies and municipalities tipping fees.
- Capturing and burning methane through high efficiency appliances like furnaces is a better way of disposing of methane compared to burning it off at source, or having it released to the atmosphere through the decomposition of manure.
- A system in which a farm produces its own energy through a biogas system could mean that the farm could be considered carbon neutral.

The province also announced at the recent Ontario Federation of Agriculture annual meeting that it would run consultations with the goal of making it easier for farmers to use off-farm organic matter in their biogas digesters.

Stay with electricity generation or switch?

With 38 on-farm digesters, Ontario has the largest cluster of them in Canada. All of those now produce electricity.

Would it make sense for them to switch to producing renewable natural gas?

That's unlikely, as they already have contracts for electricity production and the system for generation of electricity is already purchased and working on the farm.

However, that doesn't mean that farmers couldn't increase the capacity of their biogas system to take in more external or internal waste.

A second biogas digester, like this one currently in use at the Stanton farm, would be built to create the methane used in renewable natural gas. photo: John Greig

Green says that when the program in Ontario used to manage biogas electricity generation, known as the Feed-In Tariff program, was cancelled, there were 75 applications submitted.

Many of those could now be dusted off for the production of renewable natural gas.

Jake DeBruyn, new technology integration engineer with OMAFRA, says there is suddenly lots of activity around renewable natural gas, but for now, the costs will be higher in order to scrub the methane mix gas that comes off a digester from 50 per cent purity to 95 per cent purity.

He says an on-farm digester system generating electricity would require $2 million to $3 million in investment. A biogas digester system with a scrubbing and compression system so that the gas can go into the natural gas pipeline can cost closer to $5 million. The digestion systems need to be larger to make sense as well, he says.

Dyseiewicz says that Enbridge Gas is willing to build and manage the scrubbing facilities for farms, and charge a fee back to them for the service, taking some of the need to raise capital away from the farm.

Other costs include whether the farm already has access to a natural gas pipeline and the costs of extending it to the farm if it doesn't.

For many areas of the province without natural gas service, there won't be an option to put methane into the grid until the service moves closer.

The OFA has been encouraging the government and industry to increase natural gas service to the countryside as it is the least expensive energy source, but also in order to facilitate the growth of renewable natural gas on farms.

DeBruyn says natural gas is a "beautiful fuel that is reasonably priced, but there are not a lot of good ways to reduce the carbon footprint of natural gas." Renewable natural gas would help. Transport trucks are now running on natural gas, fuelled by gas stations with natural gas filling options along the 400 highway corridor.

Burning natural gas in those trucks can reduce carbon emissions by 20 to 40 per cent over diesel fuel and the fuel cost is lower. Therefore, renewable natural gas can help reduce the emissions of the transportation sector.

Natural gas is the least-expensive fuel. The price being paid for renewable natural gas will be between $20 and $25 per gigajoule (Gj), more than twice the price for natural gas pulled from the ground. But, says Dysiewicz, the price of $21 per Gj, makes renewable natural gas the least expensive form of renewable energy — equivalent to the cost of off-peak electricity.

That's why some farms are using natural gas generators to create electricity for the more electricity-intensive operations on farm.

Stanton says that he worries about being locked into the 20-year contract. Risk factors include the fact that their costs can escalate while what they are paid over 20 years will not and that the food waste that is so integral to efficient operation of the digester could go to another source or they could be forced to pay for it.

"If we didn't have it, it wouldn't make sense," he said. There's lots of food waste available now, but if many more digesters are built then the market would be tight.

How does the gas get from Ontario to British Columbia

It may seem strange that renewable natural gas would be sent from Ontario to British Columbia, when most of the natural gas in the country is in the area in between.

The truth is that the gas molecules produced in Ontario themselves may never get to B.C., but the concept of them being "notionally" in the natural gas grid is good enough. Ontario is well connected to the natural gas system across North America and so once the gas is in the system, and the utility from B.C. pays for "transportation" between the jurisdictions, it doesn't matter which gas molecules are burned in B.C. as long as they are all in the same grid. After all, the methane molecule from digested manure and other organic matter, is exactly the same as the molecules in the rest of the natural gas we burn.

COOP CARBONE

BIOMETHANE PRE-FEASIBILITY

FINAL REPORT (PRELIMINARY)

DECEMBER 2016

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Published by Coop Carbone

BACKGROUND

On the one hand, Enbridge as a fossil fuel distributor (natural gas) will soon be covered by the Ontario cap-and-trade regulation and wishes to explore innovative paths to reduce its products' footprint in order to better position itself in a carbon-regulated market. On the other hand, the agricultural sector organic wastes generate significant volumes of methane (a GHG), which can be processed in a natural gas-equivalent product: biomethane. Biomethane (or renewable natural gas – RNG) is energetically equivalent to natural gas, but is more competitive as no carbon price needs to be paid for its distribution and consumption.

In this context, Enbridge wishes to start analysing the interest of investing in anaerobic digestion projects for agricultural organic waste, in order to produce and inject biomethane in its pipeline. The main objective is to evaluate the interest in investing in such projects.

Coop Carbone has proposed a pre-feasibility assessment from a technical and regulatory standpoint, as well as for the commercial interest for the biogas project developers, considering the associated revenues and costs.

This report covers the following sections:

1. State of the Biogas Industry
2. Barrier Analysis
3. Accessibility to the Carbon Market
4. Biogas Potential Assessment
5. Costs & Benefits assessment

At the light of the results presented in the report, one can conclude there still exist a significant potential for AD projects to be explored in Ontario, especially under the new economic conditions driven by the energy and carbon markets. New factors have to be considered in a more detailed study, per region or county, that would integrate potential carbon revenues and new biomethane market. Further analysis could also include the development of innovative region-specific or project-specific business models, which would allow for the aggregation of several small projects, as well as optimisation of alternative revenues such as carbon revenues.

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1. STATE OF THE BIOGAS INDUSTRY

Agricultural activities contribute significantly to the generation of organic wastes in Ontario and represent an important source of methane emission (CH_4). Methane is a powerful greenhouse gas (GHG) having a global warming potential (GWP) of 21 tCO_2e per tCH_4. This means one tonne of methane generates the same effect on the atmosphere than 21 tonnes of CO_2. As a result, the agricultural sector is responsible for approximately 5.5% (9.4 Mt) of the total GHG emissions in Ontario, from which 16% (1.5 Mt) is associated with manure management only. Organic wastes not only include manure but also other organic waste generated by the agricultural sector, such as slaughterhouse residues, crop residues, vegetable debris, etc. The waste sector in Ontario is responsible for a total of approximately 9 Mt (around 5.5% of the total GHG emissions in Ontario), primarily caused by the anaerobic decomposition of organic waste at landfill facilities. Biogas production facilities, or anaerobic digesters, allow capturing methane and burning it to generate energy, thus reducing GHG emissions from manure management facilities and other agricultural organic residues.

The Government of Ontario, being well aware of this opportunity, has implemented the appropriate regulatory framework in order to guide biogas projects development in terms of manure management, renewable energy generation as well as carbon emissions. Those regulations have led to a few incentive programs aiming at supporting the development of the biogas industry, such as the former Biogas Financial Assistance Program, the current Feed-In Tariff program (FIT) and the new Cap-and-Trade Program. A description of this regulatory framework, as well as an overview of existing biogas projects in Ontario, is described in the following section.

1.1 OVERVIEW OF THE ONTARIO REGULATORY FRAMEWORK

NUTRIENT MANAGEMENT

For an agricultural producer, the production of manure sometimes happens to exceed the nutrients need of the crops. An excess of manure is very likely to generate environmental concerns relative to soil, water and air quality. These well-documented risks have led the Government of Ontario to proclaim a law framing the process of manure generation and management. The Nutrient management Act was proclaimed the 1st of July 2003 and on September 30, 2003, the Ontario regulation 267/03 took effect. This act plays the role of regulatory framework for waste management through various standards and protocols ranging from storage to application of manure on agricultural lands. The law and its regulations have to be considered when evaluating the feasibility of a manure management project, including anaerobic digestion projects.

The nutrient regulation represents a constraint for agricultural producers that are limited in their capacity to spread manure on lands. For instance, the application of manure is limited by the proximity to watercourse or other environmentally sensitive areas. In Ontario, field closer than 100m from municipal wells, from 15m to drilled wells, from 3 to 60m from the bank of the surface of water should not be spread with manure.

The issue of manure surplus can be solved in many ways as long as the selected management practice or technology is implemented following the requirements of the Management Nutrient act. Various options are available, such as increasing the size of the land base in the farm unit, reducing the amount of manure nutrients to handle, applying more manure to the same land base, moving manure off-site, or adopting other innovative manure treatments such as anaerobic digestion (AD). In this regard, AD should be seen not only as a biogas production facility, but also as an instrument facilitating compliance with the applicable manure management regulation and potentially reducing compliance costs. Moreover, farm-based biogas systems represent a significant opportunity for the agricultural industry to generate renewable energy, to reduce odour and to control pathogens.

For AD project developers, the starting point is the “nutrient management protocol” (online), referred to in Ontario regulation 267/03[1]. It provides technical and scientific details as well as standards to follow while developing and implementing nutrient management strategies ("NMS"), nutrient management plans ("NMP") and non-agricultural source material plans ("NASM plans"). A NMS or NMP is required to any farmer who wants to obtain approval from the Ontario Ministry of Agriculture, Food and Rural affairs (OMAFRA. The Nutrient Management protocol provides guidance and recommendations in order to facilitate compliance with the nutrient regulation’s requirements, such as nutrient units, NMS, NMP, NASM, land application requirements, registration of farms, outdoor confinement area, contingency planning, construction and siting.

[1] http://www.omafra.gov.on.ca/english/nm/regs/nmpro/nmpro01-12.htm

The following items are the most important criteria that AD project developers and farmers must have in mind regarding the nutrient regulation:

- The Nutrient Unit (NU) is probably the most important criteria related to manure management. The NU determines the farmer's obligations in terms of agricultural operations carried out at a farm unit. The NU is used to provide equivalence between the amount of manure and the synthetic fertilizer replacement value. For example, it takes the manure from 3 beef feeders to get the equivalent of 1 NU, which corresponds to the lowest value between 43 kg of N or 55 kg of P [2].

- The nutrient value of manure varies from one animal to the other. A good way to determine the nutrient value of manure is to get it analyzed by an accredited lab for nitrogen (N), phosphorus (P), potassium (K) and dry matter content. Thus, it becomes easier to respect the relative quantity of those chemical elements to spread on the fields.

- The Nutrient management strategy (NMS), valid for a maximum of 5 years, transmits to OMAFRA the required information on how manure generated on the farm is managed, how the nutrients are utilized, the number of livestock, the amount of manure produced, as well as the amount of storage available. An NMS sets out an environmentally acceptable method for managing all prescribed materials generated at an agricultural operation[3].

- The nutrient management plan (NMP) includes documentation on specific metrics: nutrient application on farm fields, crops rotation, fertilizer program, manure application and crop yield expectations. The NMP details how nutrients are to be applied to a given land base. It is based on both the components of the nutrients used and the characteristics of the field. The NMP optimizes the utilization of the nutrients by crops in the field and minimizes environmental impacts.

- For AD projects, any other components must be included in NMS and NMP, such as storage facilities, the destinations of waste generated, farm unit sketch, location of generation facilities and storage, description and dimensions of anaerobic digester facilities, distance to sensitive features[4] within the farm unit and outside within regulated distances.

[2] http://www.omafra.gov.on.ca/english/engineer/facts/05-025.htm
[3] http://www.omafra.gov.on.ca/english/nm/regs/nmpro/nmpro04-12.htm
[4] Gas, oil test and water wells, surface water, dwellings, residential areas and commercial

GREEN ENERGY AND GREEN ECONOMY ACT

The Ontario "Green energy and Green Economy Act" (GEA) has been introduced in 2009, with the main objectives of fostering renewable energy production, encouraging energy conservation and creating green jobs. The GEA main impact is the creation of several feed-in tariff rates for different types of renewable energy sources. Notable among these is the "microFIT" program for small non-commercial systems (< 10 kilowatts), as well as the "FIT" program, the larger scale version which covers a number of project types with megawatts sizes.

The Independent Electricity System Operator's (IESO) Feed-In Tariff program (FIT) is recognized as North America's first comprehensive guaranteed pricing structure for renewable electricity production. The program allows stable prices, long-term contracts for energy generated from renewable sources, including biogas. The fundamental objective of the FIT Program, in conjunction with the *Green Energy and Green Economy Act, 2009 (Ontario)* and Ontario's Long-Term Energy Plan, 2013, is to facilitate the increased development of renewable generating facilities of varying technologies using a standardized, open and fair process.

Qualified renewable energy producers have an opportunity to enter into a 20-year contract with the Government of Ontario, through which the Province agrees to purchase all electricity that is delivered into the distribution grid, at a price sufficient to cover the costs of the project with a reasonable return on investment.

For on-farm biogas projects, the FIT defines purchase prices according to the installed capacity. For projects under 100 kW, purchase price is set to 26.3 cents/kWh while projects over 100 kW, but smaller than 250 kW are granted 20.4 cents/kWh. For biogas projects out of farm (for instance regional biodigestors), FIT defines a price of 16.8 cents/kWh[5]. There are several requirements to meet in order to be eligible to the FIT program. For instance, in order to meet the "on-farm" criteria, biogas systems must be a "Regulated Mixed Anaerobic Digestion Facility (RMADF)", as defined under the Nutrient Management Act, 2002.

There are now over 30 systems in Ontario. The majority have received support from the former Biogas Financial Assistance Program and many additional biogas developers are applying to the FIT program.

ENVIRONMENTAL PROTECTION ACT

[5] More info is available at: http://fit.powerauthority.on.ca/fit-programme/eligibility-requirements/bioenergy

In 2009, Ontario became a member of the Western Climate Initiative (WCI), the largest regulated carbon market in North America, which already includes Quebec and California. The same year, the Environmental Protection Amendment Act was enacted, thus establishing the regulatory framework for an emission trading system. The Act led the way for the regulatory process that led to the cap-and-trade system, which is described in detail in Section 3: Accessibility to the Carbon Market.

The Environmental Protection Act has led to the cap-and-trade regulation[6], which includes detailed rules and obligations for entities participating in the program, and the regulation of GHG quantification, reporting and verification (Quantification, Reporting, and Verification of Greenhouse Gas Emissions Regulation)[7]. Those two regulations, described in detail in Section 3, are the foundations of the Ontario carbon market.

The Environmental Protection Act also includes the O. Reg. 359/09 (Renewable Energy Approval - REA). O. Reg. 359/09 states that a Renewable Energy Approval (REA) is required for anaerobic digestion facilities, and various documents have to be submitted to the MOECC as part of the REA Application, such as construction plans, design and operation report or noise study report[8].

Other regulations of the Act have to be considered when implementing an AD project, such as the Regulation 347: General - Waste Management[9]. The regulatory requirements regarding building, grid connection and taxation are summarized by OMAFRA at http://www.omafra.gov.on.ca/english/engineer/biogas/incentives.htm.

[6] https://www.ontario.ca/laws/regulation/r16144?_ga=1.36702304.1946619481.1454953972
[7] https://www.ontario.ca/laws/regulation/090452
[8] https://www.ontario.ca/laws/regulation/090359
[9] https://www.ontario.ca/laws/regulation/900347

1.2 Overview of existing projects

Identification of key geographical areas and key players of the industry in Ontario

The Canadian Biogas Association has recently published a map of available biogas projects in Ontario, including a general description of each of them. A total of 33 projects are listed, including the name of the farms involved, a description of their activities, characteristics of their biodigesters and their electricity capacity production (Visit ON Projects-Canadian Biogas Association for more details).

In Ontario, the biogas industry is run by two major actors' category. New project developers have the opportunity to learn from their expertise and to start higher in the learning curve.

First, the producers, processors and haulers represent the biogas inputs network. Some of those companies are Cornerstone Renewables Inc., Detox Environmental Ltd., Future Waste Management, Ontario Greenways Inc., etc. (a more detailed list in available on OMAFRA[10]).

[10] http://www.omafra.gov.on.ca/english/engineer/facts/biogas-inputs.htm

Then Ontario is marked out by an important number of qualified AD designers, developers, and consultants. Research groups and government invest considerable resources in this promising technology field. Those actors have successfully carried out many projects qualified as viable and sustainable on their lifetime. Depending on the technology to be employed, local farmers and industrials have the possibility to issue a call or tender oriented toward international designers and developers.

Here is a non-exhaustive list of on-farm and off-farm projects in Ontario:

- One of the largest projects to date is led by PurEnergy Inc., responsible for the construction of AD facility known as “Kawartha Biogas” (Peterborough County) with a 9.8 MW nameplate capacity of green electricity, sold under a Feed-in-Tariff contract reference number FIT-FPXS2N[11]. On the 15th of April 2013, the Ministry of Environment issued a Renewable Energy Approval to purEnergy Inc. to engage in the Kawartha Biogas project. The co-product is an added-value fertilizer. Feedstocks include distillers grains and syrup from the neighbour ethanol plant, fats, oil and grease and cow manure.

- Toronto Hydro Energy Services Inc. has supervised the construction and operation of a biogas cogeneration plant, the “Ashbridges Bay Biogas Cogeneration Plant”, a wastewater facility treatment plant. The plant works in a closed-loop: biogas is a bi-product of the wastewater treatment process and provides methane for the cogeneration plant, and methane is converted into electricity and heat to be returned to the treatment plant. The plant is expected to generate 9.9 MW of electricity.

- One of the most important farm-based biodigester is “Ledgecroft Farm”, a dairy farm located in Seeley's Bay with 500 head of cattle, including 225 milking cows. The farm also has 1,100 acres of high moisture corn and forages (alfalfa, corn). Back in 2009, Ledgecroft Farm had installed a 1,500m^3 digester, designed by PlanET Biogas and fed with manure and off farm material. The plant runs one 500 kW generator.

- The Harvest Energy Garden is an agri-food residues processing facility located in London, Ontario. It has a total treatment capacity of 100,000 tons/yr of local agri-food waste, including commercial food processors, grocery stores, restaurants and rendering plants. The plant generates 2.8 MW$_e$ and 2.9 MW$_{th}$, as well as 5,200 MT/yr of granular fertilizer.

[11] https://kawarthaethanol.ca/wp-content/uploads/2014/04/4_Decomissioning-Plan-Report.pdf

Project Name	Capacity	Region	Output	
			Energy	Nutrient
Harvest energy Garden	100,000 tons/yr	London, Ontario	5.7 MWCHP (2.8 MW electrical, 2.9 MW thermal)	5200 MT/year granular fertilizer
Ashbridges Bay Treatment Plant	40,000 tons/yr organics capacity	Richmond, BC	2.2 MWCHP (1.1 MW electrical, 1.1 MW thermal)	
Ledge croft farm digester plant	1500 m^3 and 2077 m^3 digester	Seelay's Bay, Ontario	500 kW	

SYNTHESIS OF AVAILABLE ANAEROBIC DIGESTER TECHNOLOGIES IN ONTARIO

The environmental concerns of agriculture activities are one of the main preoccupations of the Ontario authorities. Therefore a good agricultural waste (manure) application and management have changed the situation in the regions where they were employed. A need to reduce the use of chemical fertilizers and the amount of waste landfill became increasingly important in the near last decades due to their impact on the environment. Using an anaerobic digester helps rural areas to solve this issue.

Anaerobic digester produces biogas (50 to 70% CH_4) out of manure and waste stocks. The result is a considerable diminution of farm manure and the production of organic nutrients and fertilizers. A substitution of chemical fertilizers by organic reduces health and pollution problems in the society. A particularity with chemical fertilizers is that through their active molecules (sulfuric acid and hydrochloric acid[12]) they cross the whole food chain and reach all its levels (from plant to cows, from cows to fishes…). In addition to this, they are manufactured from non-renewable resources such as fossil fuel through polluting chemical processes. On the other hand, manure storage and landfill site cause problems such as NH_3 (ammonia) emissions with bad odour and, after deposition, nitrogen enrichment and acidification of the soil and surface water[13]. Trucks used in manure transportation represent financial costs and are also responsible for GHG emissions associated with the combustion of fossil fuel (diesel).

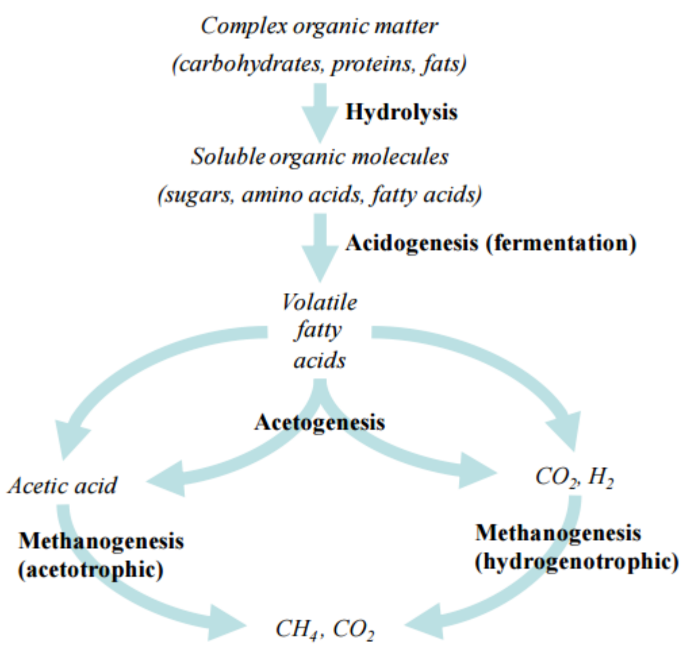
[12] http://www.agrotechnomarket.com/2014/07/disadvantages-of-chemical-fertilizer.html
[13] http://www.fao.org/WAIRDOCS/LEAD/X6113E/x6113e06.htm#b3-3.3%20Ammonia%20emission

In the perspective to avoid the environmental concerns previously described, the government of Ontario and renewable energy gas providers have massively invested in anaerobic digester technologies. The main objective of this strategy is the maximisation of the output obtained from digestion process and the reduction of environmental impacts. Those efforts over the last years have led the Ontario biogas industry to acquire and develop the most effective AD technologies. The yield rate (biogas per tonne of waste) is rapidly increasing and organic fertilizers (another main product from bio-digestion) have higher nutritious qualities.

Depending on the project scale and investment, biogas plants operate with various AD technology types. In Ontario, these technologies are generally provided by both Canadian and US companies. Given the environmental characteristics (climate, soil type), agricultural activities are similar in the two countries and thus the adaptability is almost perfect. In a less extent, some Europeans providers are involved in the Ontario biogas Industry.

AD Biochemistry and Technologies

Anaerobic digesters all use the same biological process. Biodegradation is realized through the action of a consortium of microorganisms working synergistically, in absence of oxygen (anaerobic conditions). The process of biodigestion follows four steps[14]: hydrolysis, acidogenesis, acetogenesis, and methagenesis.



Anaerobic digestion biochemical conversion pathways

[14] http://www.calrecycle.ca.gov/Publications/Documents/1275/2008011.pdf

a. Large protein macromolecules, fats and carbohydrate polymers (such as cellulose and starch) are broken down through hydrolysis to amino acids, long-chain fatty acids, and sugars.

b. These products are then fermented during acidogenesis to form three, four, and five-carbon volatile fatty acids, such as lactic, butyric, propionic, and valeric acid.

c. In acetogenesis, bacteria consume these fermentation products and generate acetic acid, carbon dioxide, and hydrogen.

d. Finally, methanogenic organisms consume the acetate, hydrogen, and some of the carbon dioxide to produce methane. Three biochemical pathways are used by methanogens to produce methane gas. The pathways along with the stoichiometries of the overall chemical reactions are:

   i. Acetotrophic methanogenesis: $4\ CH_3COOH \rightarrow 4\ CO_2 + 4\ CH_4$

   ii. Hydrogenotrophic methanogenesis: $CO_2 + 4\ H_2 \rightarrow CH_4 + 2\ H_2O$

   iii. Methylotrophic methanogenesis: $4\ CH_3OH + 6\ H_2 \rightarrow 3\ CH_4 + 2\ H_2O$

The biogas plants buildings are categorized by Vandevivere et al.[15] in 4 most common manure waste anaerobic digester technologies: One-stage continuous systems, two-stage continuous systems, multi-stage systems and batch systems:

- Single-stage digesters are less sophisticated than the two others but are simpler to design, build and operate. They also imply less financial costs. The organic loading rate is limited due to the limited capacity of methanogenic organisms to tolerate the sudden decline in pH that results from rapid acid production during hydrolysis.

- Two-stage digesters separate the initial hydrolysis and following acid-producing fermentation from methanogenesis, which allows for higher loading rates but requires additional reactors and handling systems.

- Multi-Stage digesters are based on the use of more than one reactor. Multiple digesters could then be operated in parallel. Each reactor is a separate single-stage digester. For instance, Biotechnische Abfallverwertung GmbH & Co. KG (BTA) Systems has developed a multistage digester and has an operating plant in Toronto. Linde-KCA-Dresden GmbH is another multistage system spread through several countries in Europe.

[15] Vandevivere, P., L. De Baere, and W. Verstraete, Types of anaerobic digesters for solid wastes, in Biomethanization of the Organic Fraction of Municipal Solid Wastes, J. Mata-Alvarez, Editor. 2002, IWA Publishing: Barcelona. p. 111-140

- Batch digesters: Some of the first dry digesters were envisioned as modified landfills. This resulted in the creation of batch systems that recycled leachate in a manner similar to landfill bioreactors. However, unlike landfill bioreactors the batch digester conditions were more carefully controlled and as a result biogas production rates were higher and retention times were lower.

The main advantages and disadvantages related to the technology are summarized below:

Single stage – Wet system		
Criteria	**Advantage**	**Disadvantage**
Technical	Derived from well-developed wastewater treatment technologies Simplified material handling and mixing	Short-circuiting Sink and float phases Abrasion with sand Complicated pretreatment
Biological	Dilution of inhibitors with fresh water	Sensitive to shock as inhibitors spread immediately in reactors VS lost with removal of inert fraction in pretreatment
Economic and environmental	Less expensive material handling equipment	High consumption of water and heat Large tank required
Single stage – Dry system		
Criteria	**Advantage**	**Disadvantage**
Technical	No moving part inside reactor Robust No short-circuiting	Not appropriate for wet (<5% TS) stream
Biological	Less VS loss in pretreatment Limited dispersion of transient peak concentrations of inhibitors	Low dilution of inhibitors with fresh water Less contact between micro-organisms and substrate (without inoculation loop)
Economic and environmental	Cheaper pretreatment and smaller reactors Very small water usage and heat	Robust and expensive waste handling equipment required
Two-stage system		
Criteria	**Advantage**	**Disadvantage**
Technical	Operational flexibility	Complex design and material handling
Biological	Higher loading rate Can tolerate fluctuations in loading rate and feed composition	Can be difficult to achieve complete separation of hydrolysis and methanogenesis
Economic and environmental	Smaller footprint	Larger CAPEX

Batch system		
Criteria	**Advantage**	**Disadvantage**
Technical	Simplified material handling Reduced pre-sorting and treatment	Compaction may prevent percolation and leachate recycling
Biological	Separation of hydrolysis and methanogenesis Higher rate and extent of digestion than landfill reactors	Variable gas production in single-reactor systems
Economic and environmental	Cheaper pretreatment	Larger CAPEX

1.3 Conditions under which projects may be economically viable

Key Conditions

Most of the technical and economic parameters are very project-specific and must be evaluated on a case-by-case basis. The University of Guelph has produced a biogas calculator that allows farmers to make economic decisions about biogas installations and anaerobic digestion of food waste.

The following list includes the key conditions that have to be analysed in order to evaluate a project's viability[16]:

- Electricity commercialization:
  - On-site consumption or near-by consumer will allow generating revenues (or avoided costs) from power purchase agreements. This will depend, however, on the electricity consumption on-site (needs) and on the geographical area. The presence of industries near-by, that may need electricity, may become interesting when looking for potential buyers.

[16] For more information: http://www.omafra.gov.on.ca/english/engineer/facts/07-057.htm#9

  - Interconnection: depending on the options available for biogas utilisation (e.g. for heat generation, vehicles or injection in natural gas pipeline), AD systems may involve electrical production. Since an on-farm AD system typically generates more electricity than the needs on-site, an interconnection is essential in order to act as a battery. This allows the AD facility to generate electricity at any time, send it to the grid and then use electricity at any other time.
  - Net metering: Net metering is an agreement where the energy generator (the AD operator) pays the electricity distributor only for the net amount of electricity consumed (the difference between the electricity imported from and exported to the grid).
- Use or sale of surplus heat:
  - Some manure AD systems are designed exclusively to combust biogas for heat utilization on-site. In addition to heating the digester, buildings or hot water, it may be used to heat, dry or process agricultural feeds.
  - The heat may also be sold to industries near-by, for instance greenhouses. Developing commercialization agreement for surplus heat is crucial and often makes the difference between a viable and a non-viable project. This criterion may also impact the decision-making process regarding the localization.
- Sale of other by-products (nutrients):
  - Finding a market for the nutrients (digest by-product) may increase significantly the economic performance of an on-farm AD project. The real demand depends on various project-specific parameters, such as the geographical localization and the demand for nutrients in this localization, as well as the nutrient quality achieved by the AD system (which may be variable).
  - The sale price must be interesting enough to cover - at a minimum - the cost of processing the nutrient (e.g. drying processes).
- Tipping fees: The interest of adding up to 50% of the total input from off-farm organic material[17] is not only because of off-farm material increases the AD system's performance, but also (and maybe mostly) because AD operators may benefit from tipping fees for those materials.

[17] On October 25, 2013, the Government filed amendments to O. Reg. 267/03 to enhance the anaerobic digestion approval program under the Nutrient Management Act (NMA), allowing up to 50% off-farm material as input in on-farm AD systems.

- Feedstock: Manure is animal feed that was not fully digested, so the residual content of energy can be harvested in an anaerobic digester. The following rules of thumb should be considered when identifying potential sources of organic materials:
    - Dairy and cattle manure has been successfully implemented in many jurisdictions and should be therefore prioritized.
    - Poultry or swine manure may present more challenges because of their higher nitrogen levels – other materials may be added to optimize the blend.
    - In general, AD systems work best with fresh manure, so minimizing the time between storage and AD system may be key.
    - Minimizing contamination with inorganic material is key. Sand, for instance, will settle out in the digester. Many digesters will require shutdown and removal of built-up material after 10 years of usage, so design must foresee clean-up mechanisms that facilitate the operation on a periodic basis.
    - AD systems are designed to process specific types of manure with specific physic-chemical characteristics, therefore manure and other feedstock must be suitable to the AD system. For instance, for AD systems that are not effective with highly diluted manure, processes such as bypassing milkhouse wash water should be considered.
- On-Farm Mixing of Off-Farm Source Material:
    - Mixing of off-farm source material with manure in an "on-farm mixed anaerobic digesters" may increase biogas production. Ontario now allows for up to 50% of off-farm source materials such as fats, oils and greases, pre-consumer food wastes, and other food products or by-products.
    - Typically, agri-food residues (e.g. food not commercialized) can be secured for the digester at little cost or even for a tipping fee, which makes it interesting.
    - When introducing different off-farm by-products, it is important to make changes to the recipe slowly and to calibrate the operating conditions of the AD system accordingly, in order to allow the microorganisms to adapt to the new menu.

CASE STUDY

The Canadian Biogas Association published a report study in 2013, which quantifies the benefits of biogas development to the economy, environment and energy sector[18]. The report includes a few case studies of AD projects in order to illustrate under which technical and commercial conditions biogas projects may be economically viable.

The following example is an on-farm AD project in Cobden (Ontario), Fepro Farms, that was the first biogas farm in Ontario and has been operating for over ten years, with a FIT contract for renewable electricity generation[19]. Fepro Farms is a dairy farm with 300 head of cattle, including 142 milking cows, as well as 350 acres of corn, 70 acres of small grain and 210 acres of alfalfa.

Initially, a 500 m^3 AD system generating 50kW of electricity was installed at Fepro Farms in 2003. This system was expanded to its current capacity of 2,500 m^3 and a 500 kW in 2007. The primary feedstock for AD is manure from the farm. In addition, off-farm organic residues collected from agri-food local supply chain (restaurants, grocery stores, etc.), are used to increase biogas production.

The power generators supply electricity to farm operations and buildings in priority. Then, surplus electricity is fed into the grid and sold under a Feed-In Tariff (FIT) contract, under the FIT Program developed by the Ontario Power Authority (OPA) and described in section 1.1 of this report[20]. With the FIT contract, Fepro Farms has eliminated electricity costs (that were over $30,000 per month) and has generated an additional revenue source.

During electricity production, heat produced by the generator is captured and used for different purposes: (1) to supply hot water, (2) to meet the heating requirements of the biogas system (e.g. off-farm material pretreatment) and (3) to dry corn grain seasonally.

The AD system allows converting manure into an added-value nutrient-rich digest for land application: the digest. The latter is a nutrient-enriched soil amendment, which enhances crop production when applied on agricultural lands.

[18] http://biogasassociation.ca/images/uploads/documents/2014/biogas_study/Canadian_Biogas_Study_Summary.pdf
[19] http://norwelldairy.com/uploads/userfiles/files/Fepro%20Open%20House.pdf
[20] http://fit.powerauthority.on.ca/what-feed-tariff-program

Apart from those three sources of income and avoided costs (electricity, heat and nutrients), the biogas system also generates various environmental benefits:

- GHG emission reductions: methane associated with conventional manure storage facilities is avoided.
- Other GHG emission reductions: off-farm materials used in the process are diverted from local landfills, where methane is normally generated.
- Pathogens reduction (thanks to high-temperature anaerobic digestion process), thereby reducing risks of ground or surface water pollution.
- Odours reduction (associated with conventional manure spreading).

Finally, the biogas project has generated several other environmental and social impacts:

- Fepro Farms represents an innovative form of local economic development, based on the recycling of local residues.
- The project has supported local and provincial technology and equipment providers who are developing expertise and capacity in an emerging market.
- It has created opportunities for on-farm revenue diversification and employment for family members, at a time of limited growth in the dairy industry.
- By delivering renewable electricity to the grid, the project helps Ontario achieve its GHG emission reduction targets.

Other Case Studies

University of Guelph researchers Mallon and Weersink published a report study[21] on the financial feasibility of AD for Ontario's Livestock Industries. The purpose of this study was to run a financial feasibility analysis that uses the estimations made in OMAFRA's AADCS (Agricultural Anaerobic Digestion Calculation Spreadsheet) and evaluate Ontario's standard offer of electricity tariffs for Ontario's livestock industries.

The results showed that the main technical criteria affecting the feasibility of an AD process include: the anaerobic digestion system (technology type), organic material type, biogas storage, digest storage, electricity and heat production and co-benefits of AD. The amount of biogas produced depends on the anaerobic digesters operating temperature, retention time, type of organic material used and system design.

[21] http://ageconsearch.umn.edu/bitstream/7295/2/wp070001.pdf

Another study[22], an AD benchmark study by CH Four Biogas (BC), also outlined those main criteria and more specifically the impact of the Nutrient Management Act update, allowing 50% off-farm material source of the biodigester input. The impact of this change is a significant improvement of the economic viability of the installation of an anaerobic digester in a farm. This study concludes that the proposed AD system on Farm A would be economically viable with 49% non-agricultural feedstock under the following conditions:

- Electricity tariff of $0.166/kWh
- Electricity tariff of $0.10/kWh and funding of 40% ($2,059,949)
- Biomethane tariff of $16.01/GJ
- Biomethane tariff of $15.28/GJ will produce 8.2% ROI with no funding

If Farm were to use only 25% non-agricultural feedstock, and depending on the feedstocks used, the proposed AD system would be economically viable under the following conditions:

- Electricity tariff of $0.235/kWh
- Electricity tariff of $0.10/kWh and funding of 60% ($1,732,817)
- Biomethane tariff of $30.60/GJ
- Biomethane tariff of $15.28/GJ and funding of 60% ($2,220,566)

[22] https://www.bcac.bc.ca/sites/bcac.localhost/files/AD%20Benchmarking%20Study_0.pdf

2. Barrier Analysis

Biogas from on-farm anaerobic digesters represents the largest potential source of biogas in Canada. Approximately 2/3 (68%) of the total Canadian biogas potential (810 MW or 2,420 Mm^3/year) comes from agricultural sources. Ontario is the Canadian Province that facilitates the most the implantation of biogas facilities in its province, through facilitating policy choices and regulations.

To date, there are over 30 on-farm AD systems with a total installed electrical capacity of 17.5 MWe[23], representing already 2% of the total Canadian potential. Based on available organic feedstock from food processors and farmers, the Biogas Association estimates that a total potential of 250 MW of power generation could come from biogas in Ontario. Fewer than 10% of the total potential is reached, meaning there are still some significant barriers affecting the realisation of such biogas projects.

It is interesting to note that so far, the majority of the on-farm AD projects have been implemented on medium or large farms. The small size is therefore a barrier in itself, as small farms may have more difficulties to overcome the barriers described in the section below. Indeed it is more difficult for a small farm to obtain finance and reach financial closure, to reach an interesting volume of biogas production to commercialize, to have enough resources to go through the regulatory processes, etc. Knowing that, it would be interesting to develop a regional collaborative framework that would allow several small farms to mutualize their organic residues into one regional facility.

2.1 Technological, technical and infrastructure barriers

Have the available technologies proven to be well adapted to Ontario's climate?

There is now a wide range of available anaerobic digester technologies. The operating plant using them is subject to various costs, implantation delays, and regulatory requirements. Those regulatory requirements cover a various fields of criteria such as processing management, environmental, sanitary aspects.

[23] OMAF and OMRA, Chris Duke, Presentation, March 5, 2013.

It is up to each technology provider to set the appropriate anaerobic system according to field studies over the input capacity transformation, environmental conditions (climate, relief, soil type), and the planed output production. Generally, the choice of an anaerobic digester is mainly based on the technical constraints. The various available biogas system technologies provided by Canadian companies as well as foreign ones were described in the previous section 1.2. All of those technologies are implementable in Ontario, and in certain cases adaptable to the local context (thermal insulation, higher heat during winter). This is possible due to the inside operating process and the possible physicochemical conditions replication.

From the existing on-farm projects, such as the case studies project previously presented, it appears that the AD technologies operating in Ontario have been for the most part adapted form European technologies in order to operate under local climate. Many design features made this adaptation feasible, such as the introduction of off-farm materials boosting biogas production (and temperature). Recovering heat from the electricity generation process is also a solution that allows maintaining the system's conditions under Ontario's winter conditions[24]. Insulation materials, geographical location or windbreaks are also part of the design options that have been implemented in order to maximize AD system's adaptation to Ontario's climate. After more than a decade of on-farm biogas deployment, it appears that technology providers and project developer are capable of adapting the design features in order to ensure proper operation under Ontario climate conditions.

2.2 INVESTMENT OR FINANCIAL BARRIERS

HOW ACCESSIBLE IS FINANCING FOR SUCH PROJECTS IN THE AGRICULTURAL SECTOR?

The initial cost of an AD is estimated to hundreds of thousands of dollars and in many occasions even millions. Investment costs for an AD are variable depending on the infrastructure system (electrical capacity), the efficiency, and the location. According to experts from the University of Guelph, for which several research projects have been carried out on the economics of biogas[25]: "Variable costs can fluctuate as much as the investment costs, as many of the variable costs are either directly or indirectly dependent on the initial cost of the AD. ADs involve large financial commitments that have uncertain savings, income, and costs. This makes the value of the completed project very uncertain."

[24] On coldest winter days, 50 percent of the heat might be required to maintain digester temperature, even a biogas plant with mesophilic bacteria
[25] http://bioeconproject.com/?page_id=68

The launch phase of an on-farm biogas project requires an important budget. Most of the time, this budget is raised by funding, bank financial support and various investors. All of those capital contributions are considered as well as each other. However, the emerging aspect of this industry has the effect to complicate the financial support from banks due to the undetermined risk associated with these industry activities.

Ontario government, aware of this particular context, provided many funding support and financial assistance programs. It has set up numerous renewable energy initiatives since the passing of the Green Energy and Green Economy Act in 2009[26]. The Ontario Ministry of Agriculture Food and Rural Affairs (OMAFRA) has provided farmers and agri-food businesses with 11.2 million dollars to help build renewable energy projects throughout Ontario through its Biogas Systems Financial Assistance Program, which ran from September 2008 to March 2010[27]. In 2008, through its assistance programs, OMAFRA funded 46 feasibility studies and 12 construction projects of biogas facilities[28]. Other investors (private, public) funding source contributions are more or less accessible depending on the organisation with which the farm is dealing with.

Downstream commercial conditions such as financial indicators (costs, incomes, Net Present Value, payback delay) as well as market opportunities are the key factors for the project launch. According to the technology system chosen, the production costs imply the range of electricity's and biogas' (methane) submitted price rates offered by the farm. Moreover, price rate is a key component of commercial conditions since it will make the project economically viable and establish the criteria of sale agreement. The quantity of output delivered and delivering conditions (grid connexion) are determined in the sales agreement.

AVAILABLE INCENTIVE PROGRAMS

In Ontario, there are over 30 farm-scale AD power plants with a total installed electrical capacity of 17,500 kWe (OMAF/OMRA, 2013). For the most part, those projects have been implemented with financial assistance from the OMAFRA and its former Ontario Biogas Systems Financial Assistance Program. This program consisted of 2 grant phases: The first phase provided funding designated for feasibility studies (70% of eligible costs up to a maximum of $35,000). The second phase provided funding for construction and implementation (40% of eligible costs up to $400,000). On-farm biogas expansion within Ontario is ongoing under the third-generation Feed-in Tariff program (FIT 3).

[26] Ibid
[27] Ibid
[28] https://news.ontario.ca/omafra/en/2008/10/biogas-financial-assistance-programme.html

Government financing accessibility of biogas project materialises itself by a wide range of programs and incentives established in order to support this renewable natural gas sector.

OMAFRA listed several funding programs for planning a farm-based biogas project. Some of them as defined by OMAFRA and Biogas Association are the following:

SD Natural Gas Fund

The SD Natural Gas Fund, delivered by Sustainable Development Technology Canada (SDTC), supports innovative natural gas projects, including anaerobic digestion, gas upgrading equipment and some activities related to natural gas vehicles fuelling. The fund issues calls for submissions twice a year. Eligibility and cost share levels are determined through the analysis of business case documents to be completed as part of the application process.

Northern Business Opportunity Program - Business Expansion Projects

This program supports the expansion of existing businesses in Northern Ontario. Generally, funding up to 50 per cent of a project to a maximum of $1 million. Electricity generation projects are not eligible. Other biogas production projects, such as for heating or for vehicle fuel, may be eligible and are reviewed on a case-by-case basis.

Growing Forward 2 funding assistance for Capacity Building and Implementation

Growing Forward 2 (GF2) is a federal-provincial-territorial initiative offering flexible and practical options for farm and other businesses.

The GF2 Capacity Building component supports projects that build capacity (e.g. skills development, training, audits and assessments). For example, development of the feasibility and engineering design for a biogas project may fit the criteria. Farm producers and processors are eligible for up to 50 per cent cost share of projects that fit under this component of GF2. Organizations and collaborations may be eligible to receive up to 75 per cent cost share.

The GF2 Funding Assistance for Implementation funds innovative projects that demonstrate sector benefits for the Ontario agri-food industry. Farmer and processor appliants may be eligible to receive up to 35 per cent cost share for implementation-based projects they propose, and up to 50 per cent cost share for innovative projects. Organizations and collaborations may be eligible to receive up to 50 per cent cost share for implementation-based projects, and up to 75 per cent cost share for projects considered innovative.

INVESTING IN BUSINESS GROWTH AND PRODUCTIVITY

The Federal Economic Development Agency (FedDev Ontario) offers the Investing in Business Growth and Productivity program to support economic growth and job creation. The program helps businesses to expand their markets and facilities, and to adopt new technologies and processes to improve productivity.

GREEN MUNICIPAL FUND

The Federation of Canadian Municipalities' Green Municipal Fund provides grants and low-interest loans to municipalities in support of activities in the following sectors: brown fields, energy, transportation, waste and water. Grants are offered for developing sustainable community plans, conducting feasibility studies and field tests (up to 50% of costs to a maximum of $350,000) and loans are offered to implement projects. In the waste sector, funding is available to support waste diversion projects. Eligible applicants can request up to $4 million in loans and $400,000 in grants for each project. Rates for municipalities are 1.5 per cent lower than the Government of Canada bond rate and even further below market rates.

FEED-IN TARIFF (FIT) PROGRAM

Ontario's Feed-in Tariff (FIT) Program, enabled by the Green Energy and Green Economy Act, 2009, and implemented by the Ontario Power Authority (OPA) offers the following guaranteed price schedule for electricity generated from on- and off-farm biogas.

Renewable fuel	Size	Contract price cents/kWh	Escalation percentage
On-farm biogas	≤ 100 kW	26.5	50%
On-farm biogas	> 100 kW ≤ 250 kW	21.0	50%
Biogas	≤ 500 kW	16.4	50%
Landfill gas	> 500 kW ≤ 10 MW	7.70	50%

COMMUNITY POWER FUND, COMMUNITY ENERGY PARTNERSHIP PROGRAM

The Community Energy Partnerships Program (CEPP), delivered by the Community Power Fund, is a grant program supporting community power in Ontario. The program assists eligible applicants by paying for a portion of the costs associated with developing renewable energy projects. These costs include resource assessment, legal services, engineering work and regulatory approvals. Funding under the CEPP is divided into two streams:

- The Pre-FIT Organizational Development Stream will cover 80 per cent of eligible costs, up to $20,000 for a single project, up to $30,000 for two projects and up to $40,000 for three or more projects.
- The Development and Approvals stream will cover 50 per cent of eligible costs up to $500,000 per large project or $100,000 per small project, less any previous CEPP funding.

Harmonized Sales Tax - Input Tax Credits

Businesses may recover the Harmonized Sales Tax (HST) paid on many purchases or expenses related to commercial activities, including the construction and operation of a biogas system. These rebates are called Input Tax Credits.

Federal Accelerated Capital Costs Allowance

The Federal Accelerated Capital Cost Allowance (CCA) for Clean Energy Generation program allows accelerated depreciation of eligible renewable energy system costs. A 50 per cent accelerated CCA under Class 43.2 of Schedule II to the Income Tax Regulations is available for specified energy generation equipment. In general, biogas systems are eligible for this opportunity. Class 43.2 includes equipment used to produce, store and use biogas from the anaerobic digestion of manure, provided the biogas is used primarily for electricity or the production of heat for use in an industrial process.

Climate Action Plan

With the new Climate Action Plan released last June[29], Ontario government plans an investment of $100M over the next 4 years in the biogas technologies. This aims to promote the development of renewable energy and reduce greenhouse gas emissions. Moreover the province intends to invest 15 to $20M to pilot a program that uses methane obtained from agricultural materials or food wastes for transportation purposes, with funding for commercial-scale demonstration projects.

As part of the new Action Plan, Ontario intends to introduce a renewable content requirement for natural gas and provide supports encouraging the use of cleaner, renewable natural gas in industrial, transportation and building sectors. The government will consult with industry on the implementation of this requirement. The goal is to ensure the lowest possible carbon content to help reduce building and transportation emissions. Methane released from sources like landfills, municipal green bin collection, agricultural residues, livestock manure, food and beverage manufacturing waste, sewage treatment plants and forestry waste can be renewed and directly substituted for conventional natural gas. Renewable natural gas is a low-carbon fuel that does not add new carbon to the atmosphere. It is fully interchangeable with conventional natural gas and uses the same infrastructure.

2.3 Regulatory Barriers

The Nutrient Management act was proclaimed in 2003. It represents the regulatory framework in force that regulates the on-farm anaerobic digester activities. We previously described all the parts of this regulatory framework. Since 2003, Ontarian Government has initiated many actions view to improve and facilitate the development of this industry. A major action among those taken is the possibility of adding up to 50% (initially 25%) of off-farm material sources to anaerobic digester feedstock. In fact the regulation allows qualifying facilities to accept up to 50 per cent (by volume) off-farm feedstock[30].

[29] https://www.ontario.ca/page/climate-change-action-plan
[30] On October 25, 2013, the Government filed amendments to O. Reg. 267/03 to enhance the anaerobic digestion approval program under the Nutrient Management Act (NMA)

OMAFRA describes the positive results of this change: "Off-farm feedstock has the potential to greatly increase biogas production compared to basic manure and other agricultural by-products. There may also be an opportunity to receive income from tipping fees when receiving off-farm source materials, as some materials have high disposal costs through other conventional waste management systems."[31]

However regulatory processes can still generate some delays during the project development phase. For instance, delays may be important for the approval of a Nutrient Management Plan or Nutrient Management Strategy. Before AD system commissioning, those delays may generate significant costs. Probable additional costs could result from the need for financial assurance due to the designation as a waste disposal site and from testing and meeting heavy metal criteria for compost, which may be difficult[32].

Important delays may also occur when requesting the Renewable Energy Approval (REA). According to the Agrienergy Producers Association of Ontario, those barriers are due to a limited knowledge of Biogas and anaerobic digestion within the Ministry of Environment and the duplication of requirements between different applications.

[31] http://www.omafra.gov.on.ca/english/engineer/biogas/incentives.htm
[32]Don Hilborn, Progress, Regulations and Innovations With Biogas Production in Ontario, Ontario Ministry of Agriculture, Food and Rural Affairs [Online] http://www.oaft.org/userfiles/oaft-agm-hillborn.pdf -page14

3. ACCESSIBILITY TO THE CARBON MARKET

3.1 OVERVIEW OF THE CAP-AND-TRADE SYSTEM

For an offset credit project developer, the accessibility to the carbon market primarily depends on the climate policy and regulatory framework. This framework defines what type of project will be eligible to carbon credits (e.g. biogas projects, renewable energy projects, forestry projects, etc.), what are the specific eligibility criteria (e.g. start date no earlier than X) and how to calculate the emission reduction (tCO_2e) and the associated carbon credits.

Since climate negotiations began at the beginning of the years 2000, states and provinces look for economic, regulatory and technology solutions to cut GHG emissions. The majority of the experts see cap-and-trade as the most environmentally and economically sensible approach to controlling GHG emissions, the primary driver of global warming. As other provinces and European states, the government of Ontario has been considering the implementation of a "cap-and-trade" regulation. The principle of the cap-and-trade is the following:

- the "cap" sets a limit on total emissions within a given jurisdiction. The cap is the total volume of allowances (one allowance = 1 tCO_2e) surrendered by the government in the market during a given year.
- all regulated or "covered entities" have to purchase allowances for a volume equivalent to their GHG inventory.
- at year 0, the cap (total available allowances) is equivalent to the total emissions of the regulated entities. Hence the demand theoretically equals the offer.
- as of year 1, the cap decreases at a defined yearly rate (e.g. 5%), which is calculated based on the emission reduction target at the end of the period (e.g. 20% below 1990 level by 2020).
- as a result, a progressive increase in demand for allowances is generated with respect to the offer (the cap). This situation induces a progressive price increase for allowances.
- as the price on carbon increases, emission reduction projects become more and more attractive to regulated entities, leading to additional emission reductions.

In 2009, Ontario became a member of the Western Climate Initiative (WCI), the largest regulated carbon market in North America, which already includes Quebec and California. The same year the Environmental Protection Amendment Act was enacted, thus establishing the regulatory framework for an emission trading system. The Act paved the way for the regulatory process that led to the cap-and-trade system:

- In February 2015, the Ontario Ministry of Environment and Climate Change (MOECC) had released a report, identifying carbon pricing mechanisms as "necessary to reduce emissions of GHG in Ontario".
- Two months later, in April 2015, Ontario government announced the implementation of a GHG cap-and-trade program. Little details were released at this time but the Province made clear that the program would be implemented through the WCI. Hence Ontario cap-and-trade carbon markets will be linked with Quebec and California.
- In November 2015, the MOECC published the "Cap and Trade Program Design Options"[33] which includes the details of the cap-and-trade mechanisms, design options, and questions that stakeholders were encouraged to comment on. Stakeholder feedback was reviewed and incorporated into the Act.
- In February 2016, the Ontario government officially published the proposed cap-and-trade system in Bill 172: the Climate Change Mitigation and Low Carbon Economy Act.
- Three months later, in May 2016, the Bill received the Royal Assent. It thereby establishes the foundation for Ontario's cap and trade regime in several ways:
    - It establishes an official target for Ontario GHG reduction: 37% below 1990 level by 2030 and 80% below 1990 level by 2050.
    - It requires targeted entities to quantify, report, and verify their GHG footprint.
    - It obliges the Ontario government to propose a climate change action plan to achieve these targets.
    - It establishes a framework for GHG cap and trade in Ontario.
    - It allows the injection of all revenues into a new "GHG Reduction Account" in order to fund green initiatives that reduce or support GHG reductions[34].

[33] http://www.downloads.ene.gov.on.ca/envision/env_reg/er/documents/2015/012-5666_Options.pdf
[34] Ontario expects to generate approximately CND$ 1.8-1.9 billion per year in proceeds from its cap-and-trade programme

The two underlying regulations are the cap-and-trade regulation[35], which includes detailed rules and obligations for entities participating in the program, and the regulation of GHG quantification, reporting and verification (Quantification, Reporting, and Verification of Greenhouse Gas Emissions Regulation)[36].

GHG QUANTIFICATION, REPORTING AND VERIFICATION REGULATION

The mandatory reporting of GHG emissions is the first cornerstone of any cap-and-trade regime. Based on the emission, targets will be defined as well as the burden sharing among the different covered entities. Collecting data on emissions is used to:

- guide the reporting process
- understand, manage and cut emissions
- support the implementation of Ontario's cap-and-trade program
- provide a baseline for companies

The new regulation "Quantification, Reporting, and Verification of Greenhouse Gas Emissions Regulation" has been approved under the name *O. Reg. 143/16*, under the *Climate Change Mitigation and Low-carbon Economy Act, 2016*. Along with the cap-and-trade regulation, it supports the implementation of Ontario's cap-and-trade program. The new regulation will take effect on January 1, 2017, and applies after January 1, 2017.

According to the regulation, industrial facilities and natural gas distributors with emissions of 10 ktCO_2e per year are required to report or "declare" those emissions. New reporting rules that took effect on January 1, 2016, cover the most GHG-intensive activities including the combustion of fuels from fuel suppliers and distributors: fuel suppliers that sell more than 200 liters of fuel per year as well as electricity importers must report their emissions.

The reporting will be made each year, through the ministry on-line platforms and following the quantification protocols included in the regulation for each sector of activity. Generally, the GHG emissions are either emissions generated by the consumption of fossil fuels (propane, natural gas, heavy fuel-oil, etc.), combined with the emissions from chemical processes, for instance in the cement or aluminum industry. Emissions associated to the "footprint" of a product or an activity, located upstream or downstream the facility, are <u>not</u> accounted for. Emissions accounted for are the "direct" emissions, i.e. the emissions generated in the defined perimeter of the facility and that can be measured.

[35] https://www.ontario.ca/laws/regulation/r16144?_ga=1.36702304.1946619481.1454953972
[36] https://www.ontario.ca/laws/regulation/090452

Once the cap-and-trade regulation enters into force (January 1, 2017), facilities declaring annual GHG emissions greater to the applicable threshold (e.g. 25 $ktCO_2e$/year) will be officially "covered" by the cap-and-trade system. For instance, an entity distributing in Ontario electricity produced outside Ontario, and having declared emissions over 25 kt.

Cap-and-Trade Regulation

The cap-and-trade program regulation took effect on July 1, 2016, and the first compliance period will begin as of January 1, 2017. The regulation defines the requirements for entities participating in the program (covered entities), including:

- GHG emission caps
- Entities covered by the program ("covered entities")
- Compliance
- Auction and sale of allowances through auctions
- Distribution of allowances

As in Quebec, regulated entities will include industrial emitters (cement, pulp & paper, aluminum, etc.), oil and gas distributors, as well as electricity importers. Entities owning facilities above 25 $ktCO_2e$ will be "regulated entities" and will have to purchase and deliver to the government emissions rights (allowances with or without offset credits) equivalent to their annual GHG inventory. Additionally, fuel suppliers that sell more than 200 liters of fuel per year and electricity importers must also participate in the program.

Voluntary participants meeting certain criteria will be able to voluntarily "opt in" to the regime, which is a quite innovative mechanism that aims at maximise the accessibility to the carbon market.

Mandatory and voluntary participants will be responsible for their emissions starting on January 1, 2017. The first auction of emission allowances will be held in March 2017.

Entities or individuals who don't have emissions to report (and hence do not have a compliance obligation) can also participate in the auction but their participation is limited to a certain purchase volume per auction as well as holding limits.

Entities or individuals who don't have emissions to report (and hence do not have a compliance obligation) can also participate in the auction but their participation is limited to a certain purchase volume per auction as well as holding limits.

At the end of a compliance period, all covered entities must deliver the amount of emission rights equal to their total GHG inventory. Participants have 10 months to complete this compliance obligation. For instance, for the compliance period ended December 31, 2020, participants have until November 1, 2021, to meet their obligation and deliver the correct amount of emissions rights (allowances with or without offset credits).

THE "CAP"

In order to facilitate the transition for the economy, Ontario government proposes to set the 2017 caps at its best estimate of what 2017 emissions will be. More specifically, the Province proposes to set the cap at 142,332,000 allowances, which is equal to 142,332,000 tCO_2e. This amount takes into consideration expected growth in the economy as well as new and expanding facilities. This cap will decline each year to support a reduction of Ontario's GHG emissions to the following levels:

- 15% below 1990 levels by the end of 2020
- 37% below 1990 levels by the end of 2030
- 80% below 1990 levels by the end of 2050

Moreover, the government has proposed an "assistance factor" of 100% in the first compliance period (i.e. up to 2020) for the industrial and institutional entities. It means that until 2020, any industrial and institutional "covered entities" will receive free 100% of their required allowances. This assistance factor will be reassessed prior to the beginning of the second compliance period (2021-2023).

THE "COVERED EMITTERS"

Once they have declared emission over the applicable threshold for their sector of activity, some entities will become regulated or "covered". As of 2017, those emitters will be required to cover each tonne of their total GHG inventory until at least 2020. For instance, a 100-kt/an emitter must purchase 100,000 emission rights (allowances with or without offset credits), either at governmental public auctions or on the secondary market (over-the-counter or OTC). In any case, there will be a cost associated with each tonne of declared CO_2e, which must be supported by the emitter. But it also means the reduction of a tonne leads automatically to a cost saving, which may be used either to pay-back or to justify an emission reduction project. The section "Latest development" provides an overview of the current allowances market prices.

When designing the cap-and-trade system back in 2008, the government took into consideration that some industries face international competition and have therefore little control on the price of their products. For those industries, any increase in production costs due to carbon pricing could possibly compromise their viability. Taking this into account, and in order to avoid carbon leakage (i.e. industries relocating their activities in other jurisdictions where there is no carbon pricing), some emitters will receive 100% of their GHG emissions in free allowances for the first compliance period.

The covered emitters, or mandatory participants to the cap-and-trade program, include the following categories:

- Electricity generators and importers – either an entity that generates electricity from fossil fuel directly imported from another province or state, or an entity that first imports electricity into the province.
- Industrial emitters – entities that own a facility (such as pulp & paper plant, iron or hydrogen process plant), having annual GHG inventory above 25 ktCO_2e.
- Institutions – similar to industrial emitters, include entities owning a facility with annual GHG inventory above 25 ktCO_2e.
- Fuel distributors – entities that are fuel distributors and who (i) distribute to an Ontario consumer, (ii) deal with volumes of 200 liters or more, and (iii) first place the transportation fuel into the market.
- NG distributors – entities that, in aggregate, are associated with annual GHG emissions of 25 ktCO_2e or greater, and operate at the point where the gas is transferred from pipeline into the distribution network for local customers.
- “Opt in” participants – entities with annual GHG emissions of 10,000 – 25,000 tonnes, who are required to submit emissions reports but are not required to have them verified, can choose to opt in as voluntary participants.

THE “OFFSET CREDITS”

An offset credit is a type of emission right (equivalent to an allowance, one tonne of CO_2e) that can be used by a covered entity in order to cover its emissions. Ontario will develop an “Offset Credit Registry” and will issue credits for GHG reductions generated in the “non-covered” sectors by non-covered entities. As in Quebec, mandatory and voluntary participants would be able to use offset credits to a maximum of 8% of the total compliance obligation. The government has not yet developed the “offset protocol”, to be integrated in the regulation in order to define what type of project can generate offset credit and according to what rules. The MOECC has published a Request for Proposal in October 2015, aiming at the development of 13 offset protocols. For the agricultural sector, the proposed offset project types included N_2O Reductions from Fertilizer Management in Agriculture, Emission Reductions from Livestock, Organic Waste Digestion Protocol, grassland conservation and conservation cropping.

Regulation Enforcement

Entities that have failed to deliver the correct amount of emission rights on time will receive a three-to-one penalty. This means for each emission right missing, they will have to surrender the emission right plus three other, for a total of four. The entity's account can be suspended if it fails to surrender the required amount of emission rights (allowances with or without offset credits) and the emitter may be subject to fines.

3.2 Latest developments in the Western Climate Initiative (WCI)

Policy Development

The Western Climate Initiative (WCI) is a collaboration scheme that involves jurisdictions working together to implement emissions trading policies in order to tackle climate change at a regional level. It is currently a regional agreement between two jurisdictions (Quebec and California) and their respective cap-and-trade regulation. Since January 1, 2013, large industrial emitters (above 25 ktCO_2e per year) have to report annually their greenhouse gases (GHG) emissions. Since January 1, 2015, fuel distributors also have to cover the emissions associated with their fuel volumes that are consumed within the jurisdiction. Those regulated emitters have to "cover" their emissions with "emission rights" that can be traded on the WCI carbon market. The term "emission rights" comprises both emission units (also called allowances) and offset credits. Allowances are created by the jurisdiction's authority and sold through WCI auctions. Offset credits are granted to project developers who develop a project that reduces GHG emissions following a specific offset protocol (for instance, agricultural methane abatement project) included in the cap-and-trade regulation.

The most important development of the last year is certainly the announcement of Ontario's plan to integrate the WCI. Ontario's government is currently working on the details of their scheme, and the launch of their carbon market is expected at the beginning of 2017. This is a major success for the WCI and for the carbon markets in general. This will increase the size of the joint market, and thus its liquidity and opportunities. It will also reinforce the probability that the market will be operating post-2020. From a Quebec perspective, the integration of Ontario will cancel the competitive distortion that the carbon market could create between the two jurisdictions. This announcement is also to be understood in the larger context of enhanced cooperation between Ontario and Quebec on climate change and energy policy. Additional announcements were made recently, notably that the two jurisdictions will cooperate to harmonise as much as possible their offset protocols, regarding project types and eligibility criteria.

Federal elections took place last October and the Liberal Party won. The Liberals want a strong regulation to curb carbon emissions, including a carbon pricing mechanism, which was confirmed on November 9th, 3 weeks before the Paris Conference of the Parties (COP 21). Although it is still not clear what exactly are going to be the impacts and the mechanisms implemented to put a price on carbon, the Liberal Party tends to delegate more powers to provinces. Therefore we can expect the current WCI agreement and underlying market are not going to be impacted negatively on the short-term.

On the western side, a new NDP government in Alberta recently announced that it will strengthen the current carbon regulation starting next year, and that it will revise the entire scheme post-2017. Although Alberta is still independent from the WCI, the province has introduced legislation last May that has formalized the new carbon price at 20 CND a tonne in 2017 and 30 CND a tonne in 2018. BC and Manitoba are also expressing interest in the carbon market, but with no clear plan expressed yet. Overall, both provincial and federal climate change regulations are in intense discussions in Canada and raises interest of the government, which is likely to be positive for the Canadian industries already involved in the carbon market.

On the US side, California is in the process of defining its post-2020 targets, and the communication and court battles are concentrated there. The GHG-reduction target for 2030 has been set at - 40 % compared to 1990 levels. The target for 2020 was 0% (-20% in Quebec), which means that reduction efforts in California in the next decade will be intense, thus inducing a likely increase in demand. Carbon market was confirmed as a key mechanism to get there which means that, if their markets are still joint by then, these targets may have an upward effect on the carbon price in Quebec after 2020, or even slightly before.

Quebec, on its side, has defined its post-2020 target at 37.5% and Ontario at 37%. Right now, we don't anticipate any decision by the Quebec or Ontario government that would not strengthen the carbon market. Also to be noted: Mexico announced its intention to launch its own carbon market in 2017 and to link it to the WCI afterwards[37].

Internationally, the carbon world is currently preparing for the COP 22 in Marrakech in a few months (November 2016). This conference is referred to as an "implementation COP", will assess the progress on decisions already taken in past COP (Warsaw, 2013; Lima, 2014; Paris, 2015) on enhancing the mitigation level as well as enhancing the provision of financial

[37] http://carbon-pulse.com/mexico-to-launch-carbon-offset-trading-in-2017-will-pursue-link-to-wci-markets/

resources by developed countries, notably through the Green Fund. In any case, carbon-pricing schemes (and carbon markets in particular) are again at the top of the agenda of the negotiators, as it is still perceived as an efficient way to curb emissions. Whether these markets will be linked worldwide after 2020 remains to be seen. Overall, climate change is again top of the agenda is many parts of the world and Canada seems to be back on track.

OVERALL MARKET STATE

Six joint auctions have been held so far in 2015 and 2016. The following table summarizes the main results in terms of price, volume and other statistics.

TABLE 1: AUCTIONS RESULTS

Indicator	2015 – Auction 2 (February)	2015 – Auction 3 (May)	2015 – Auction 4 (August)	2015 – Auction 5 (November)	2016 – Auction 6 (February)	2016 – Auction 7 (May)
Floor price (USD)	12.10	12.10	12.10	12.10	12.73	12.73
Floor price (CAD)	15.01 (1.2403)	14.78 (1.2212)	15.84 (1.3091)	16.16	17.64	16.40
Quantity offered	73 610 528	76 931 627	73 429 360	75 113 008	71 555 827	67 675 951
Quantity sold	73 610 528	76 931 627	73 429 360	75 113 008	68 026 000	7 260 000
Settlement price (USD)	12.21	12.29	12.52	12.73	12.73	12.73
Settlement price (CAD)	15.14	15.01	16.39	17.00	17.64	16.40
% Settlement above floor	0.9% (0.13 CAD)	1.6% (0.23 CAD)	3.5% (0.55 CAD)	5.1% (0.84 CAD)	0%	0%
Demand / Supply[38]	1.14	1.16	1.28	1.14	0.95	0.11
% Sold to emitters	93.5%	93.6%	95.2%	89.3%	97.5%	99.8%

[38] Calculated as the total of qualified purchase offers, divided by the total of allowances available at the auction.

In 2015, the price stayed well within 1$ above the floor price for the whole year. The price witnessed a 9.2% increase between May and August 2016 (CAD). It is a significant difference, but the vast majority of the increase is due to the exchange rate (7.4 %) and only a small portion (1.8 %) is due to fluctuations in the carbon market itself.

The carbon market is currently stable – except for the fluctuations of the exchange rate, from a Canadian point of view. It would be presumptuous to infer modifications in the overall outlook of the market based on these differences. The small increase in the third trimester may be due to the fact that this auction was the last opportunity for Californian companies to get emission right on time for their partial, annual compliance deadline.

The May 2016 auction was the first one with a significant drop in demand compared to the quantities offered. Unlike the last auctions, where all or nearly all of the allowances offered for sale where purchased, only 11% per cent of the available allowances were purchased at the May auction. Although auctions have always been subject to a certain level of uncertainty, the results from the May auction and the current market conditions create greater uncertainty. So far, it is difficult to speculate on whether those last results are the beginning of a trend that will continue and how long it might last.

Overall, the allowance market remains long but stable and the prices are clearing slightly above the floor price or at the floor price, which can be correlated to an over-allocation of allowances in the overall market Quebec-California. Indeed a surplus of 31 million allowances has been confirmed lately, beginning of November 2015, following the end of the first compliance period (2013-2014). The first compliance period for California and Quebec's linked markets ended on November 1st, obliging industrial plants and power stations to surrender allowances covering all their emissions for 2013 and 2014. According to Point Carbon's modelling, it is estimated that California's surplus over the two years is approximately 25 million tonnes, Quebec accounting for the rest (6 million).

OFFSET MARKET

Offset credits (or carbon credits) are issued to projects that reduce emissions on a voluntary basis. Therefore, offset credits are exclusive to the "non-covered" sectors, such as waste management, agriculture or forestry. Four project types can generate offset credits so far in Quebec: landfill gas capture and destruction, anaerobic digestion in agriculture, ozone depleting substances (ODS) and mine methane capture (MMC). Under California's regulation, those four project types are also approved, plus forestry and urban forestry.

In Quebec, the issuance of offset credits is still very low due to the lack of approved offset protocols adapted to the Quebec context. To date, only 8 projects have been registered (6 in waste disposal sites and 2 in ozone-depleting substances). A very first issuance of 161,510 credits took place in July 2015, with the Ozone Depleting Substances (ODS) project Recyclage ÉcoSolutions (RES). The credits were sold to Gaz Métro, a Quebec natural gas distributor[39]. A second issuance was announced on October 28th, as 11,205 credits were issued from a Quebec landfill project[40] and then 2 other ones for other landfills.

Some positive signs begin to appear, thus reflecting Quebec's offset market may be stimulated on the short-term. For instance, the MDDELCC recently announced the new protocol for mine methane capture (MMC) and another one for forestry projects (afforestation and reforestation on private lands), to be published for comments by the end of the year. As mentioned earlier, the MOECC's RfP covering the adaptation of 13 offset protocols was published recently, specifying that the protocols will be applicable both in Ontario and Quebec. These are positive signs that the Quebec offset market may grow in the near future.

In California, the offset market is still thriving way beyond Quebec's market. To date, more than 23 million offsets have been issued in California (including 11.5 million offsets from early actions). Of this number, 10 million come from ODS projects, 12 million from forestry and the rest from livestock projects. According to California Carbon analysts, the offset average price is currently estimated to 11.1 USD (November 9th), approximately 1.5 USD spread compared with the last auctions results. The overall offset issuance is summarized in the table below::

TABLE 2: OFFSET ISSUANCE TO DATE (CALIFORNIA AND QUEBEC)

Protocol	**California**	**Québec**
Forestry	28,199,666	No protocol yet
Urban forestry	0	No protocol
ODS	12,063,650	467,808
Livestock	2,519,594	0
MMC	3,126,092	0
Landfill gas	No protocol	37,800
Rice	0	No protocol
TOTAL	**45,909,002**	**505,608**

[39] http://www.novae.ca/2015/10/gaz-metro-achete-les-premiers-credits-carbone-quebecois/
[40] http://californiacarbon.info/2015/11/02/quebec-issues-second-batch-offsets-landfill-methane-project-earning-11205-credits/

3.3 LIKELY REQUIREMENTS FOR BIOGAS OFFSET PROJECTS

Offset credits (also called carbon credits) are generated by projects that effectively reduce GHG emission through abatement or sequestration. For example, a project that allows the capture and destruction of methane from the manure storage facilities could earn offset credits, since the project reduces GHG emissions in the atmosphere.

Offset credits can then be sold to regulated facilities in order to meet their compliance obligations. Indeed, mandatory and voluntary participants that want to reduce compliance costs can use offset credits instead of allowances, up to a limit of their total compliance obligation (8%). For a jurisdictional standpoint, the main purpose of offset credits is fostered emission reductions in sectors not required to comply with the cap-and-trade program (mainly forestry, agriculture and waste management).

Only specific project type can generate offset credit according to general rules and good practices that have been defined internationally, based on standards and programs such as ISO 14064 or the GHG Protocol. At the very least, Offset credits must be real, enforceable, permanent, quantifiable, additional, verifiable and unique. As part of the WCI, Ontario will have to follow the recommendations defined and published by the WCI members[41].

The specific rules proponents must follow for specific project types are defined through the “offset protocols”. Those protocols will be developed for Ontario and will be based on the criteria set out in offset project protocols to be developed in conjunction with Quebec. According to the terms included in the request for bids issued by the MOECC last year, prioritized protocols will include Ozone Depleting Substances, Landfill Gas Capture and Mine Methane (all three of which have been approved for use in Quebec), followed by protocols for forestry and agricultural projects (including biogas projects).

Biogas projects in the agricultural sector could be recognized through an “Emission Reductions from Livestock” Protocol. The protocol would include the emission reductions associated with management of manure on livestock operations including those associated with biogas facilities. Since the protocol won’t be developed from zero but rather adapted based on existing protocols, chances are that the protocol will be similar to Quebec’s Protocol #1 “Covered Manure Storage Facilities – CH_4 destruction”[42].

[41] Those recommendations are available at: http://www.westernclimateinitiative.org/component/remository/Offsets-Committee-Documents/Offsets-System-Essential-Elements-Final-Recommendations
[42] http://legisquebec.gouv.qc.ca/en/pdf/cr/Q-2,%20R.%2046.1.pdf

This offset protocol covers any project reducing GHG emissions by destroying the CH_4 attributable to the manure of an agricultural operation in Quebec. Species of livestock include dairy cow, heifer, swine, bull, slaughter cow and heifer, steer, backgrounding cattle and dairy calf. The project must involve the installation of a manure storage facility cover and a fixed CH_4 destruction device. The project must enable to capture and destroy CH_4 that, before the project, was emitted to the atmosphere. The CH_4 must be destroyed on the site of the manure storage facility where the CH_4 was captured, using a flare or any other device.

According to the RfB, another protocol, "Organic Waste Digestion Protocol", is planned to be developed for Ontario and Quebec. This protocol targets GHG reduction projects that "divert and anaerobically digest eligible organic waste and/or wastewater streams that otherwise would have gone to uncontrolled anaerobic storage, treatment and disposal systems, such as solid waste landfills or on-site anaerobic wastewater treatment facilities. The protocol should also address the co-digestion of eligible organic waste streams with livestock manure."

The combination of both protocols could be interesting for biomethane projects operating at the regional level and aggregating organic waste for several sources and several types.

According to the RfB, Ontario will welcome feedback on the draft regulatory proposal to offset credits. There will also be opportunities to offer input on the development of offset protocols during the process, including on the rules proponents must follow to be eligible to apply for credit creation.

4. Biogas Potential Assessment

This section aims at estimating the potential for implementing additional biogas production facilities in Ontario, based on the current volumes of available organic feedstock (input material). Based on available data, the analysis includes an estimation of the volume of raw material generated from the Ontario agricultural sector, which could be made available for biogas projects. Then, based on this volume of available raw material, and taking into account the existing projects, the analysis includes an estimation of the potential for biogas projects in the Ontario agricultural sector.

4.1 Raw Material Available for AD Projects

In Ontario as in any other province in Canada, the main agricultural waste sources include manure and crop residues. Those are the main feedstock for biomethane projects and can be combined with residues from agri-food industries. In order to appreciate the potential development of the biogas industry in Ontario, it’s necessary to quantify the scale of available agricultural residues in Ontario, which could be used as feedstock for anaerobic digestion projects. This analysis will be carried out per agricultural feedstock type: crop residues and manure.

4.1.1 Crop Residues

Crop residues are identified as the unused part of the crops. In Ontario, grain corn is clearly the most important crop residue source, although winter wheat, soybeans and hay also represent significant volumes of harvestable residues (expressed in tonnes/acre).

Volumes of crop residues grown in Ontario can be quantified using data from Statistics Canada (Statistics Canada, 2007a). For this estimation, it is important to note that the crop production data are represented by the total mass recovered, water mass being subtracted (dry matter content). Dry matter content of the reported crops were estimated from assumed water contents as recommended by Ralevic and Layzell (2006) and reported in Table 3.

The unused parts of the plants were estimated from the harvest index for each crop (Ralevic and Layzell, 2006) and the amount of removable residues were assumed to be 50% of the unused biomass. The harvest index is defined as the ratio of crop production over the total biomass (crop production and unused part of the plant)[43].

This analysis leads to a total quantity of crops residue estimated to 4724 kt, generated in Ontario and theoretically harvestable and available for future anaerobic digestion projects.

TABLE 3: ONTARIO 2007 CROP PRODUCTION AND ESTIMATED CROP RESIDUES

Crop	Area[1]	Crop Production[1]	Water Content[2]	Dry Matter Production[3]	Harvest Index[4]	Total Residue[5]	Removable Residue[6]
	(1000ha)	(kt)	(%)	kt(dry)	(%)	kt(dry)	kt(dry)
Wheat	313	1442	16%	1212	50%	1212	606
Oats	36	88	16%	74	50%	74	37
Barley	67	218	16%	183	50%	183	91
Grain Corn	832	6,985	16%	5868	50%	5868	2934
Mixed Grains	51	147	16%	123	50%	123	62
Canola	14	28	16%	23	50%	23	12
Soybeans	900	2000	16%	1680	50%	1680	840
Flaxseed							
Rye	20	43	16%	36	50%	36	18
Tame Hay	1016	5,216	32%	3547	95%	187	93
Fodder Corn	121	3992	70%	1197	95%	63	32
Total	**3371**	**20159**		**13944**		**9449**	**4724**

Legend:

1 Statistics Canada. 2007a. Field crops reporting series. Catalogue no. 22-002-XIE, Vol. 86, no. 8

2 Assumed values (Ralevic and Layzell, 2006)

3 Calculated as Production X (1-water content)

4 Assumed values (Ralevic and Layzell, 2006). This is the ratio of production (e.g. grain) over total biomass

5 Calculated as (DM production/harvest index)-DM production

6 Assumes 50% of total residue can be removed as a bioenergy feedstock (Ralevic and Layzell, 2006)

[43] Peter Ralevic and David B. Layzell, *An Inventory of the Bioenergy Potential of British Columbia* http://www.cesarnet.ca/biocap-archive/images/pdfs/BC_Inventory_Final-06Nov15.pdf

Another methodology can be used to carry out the assessment of crop residues available in Ontario: the raw material source from crop residues with respect to the county of origin. The 41 counties of Ontario are then grouped into five regions: southern ON, northern ON, eastern ON, western ON and finally central ON. The result shows that the western ON provides the most important quantity of crop residues available. The collection of data from those regions leads to a total amount of 3213 kt of crop residues theoretically available for anaerobic digestion projects.

Region	Southern Ontario	Western Ontario	Central Ontario	Eastern Ontario	Northern Ontario	Total
Crop production (kt)	848	1255	389	554	77	3123

This estimation is more conservative than the first one using harvest index for calculation. In terms order of magnitude, the assessment leads to a conclusion that the actual volume of available crop residues probably range between 3000 and 5000 kt.

4.1.2 Manure

The volumes of manure generated per farm or region is obviously proportional to the number of animals (# heads). Manure composition, and therefore biogas generation potential, is also widely different depending on the animal type.

Canadian Gas Association has published an overview of the total quantity of manure produced across Canada[44]. The estimated manure production for the most important animal populations is retrieved from Statistics Canada data for cattle (Statistics Canada, 2007b), hogs (Statistics Canada, 2007c), sheep (Statistics Canada, 2008) and poultry (Statistics Canada, 2007d).

Then, manure production was calculated using Statistics Canada animal population data as well as 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 4.64 for cattle to 0.0101 for turkeys.

[44] Potential Production of Methane from Canadian Wastes, Canadian Gas Association and Alberta Research Council, Sept. 2010.

TABLE 4A: CANADIAN AND ONTARIAN PRODUCTION OF CATTLE AND HOG MANURES

Region	Cattle			Hogs		
	Number[1]	Manure Production		Number[2]	Manure Production	
	(x1000head)	(kg dry/head/d)[5]	(dry Mt/yr)[6]	(x1000)	(kg dry/head/d)[5]	(dry Mt/yr)[6]
Canada	15885	4.64	6.726	14437	0.564	2.526
Ontario	1953	4.64	0.827	3790	0.564	0.663

TABLE 4B: CANADIAN AND ONTARIAN PRODUCTION OF SHEEP AND CHICKEN MANURES

Region	Sheep			Chicken		
	Number[3]	Manure Production		Number[4]	Manure Production	
	(x1000head)	(kg dry/head/d)[5]	(dry Mt/yr)[6]	(x1000)	(kg dry/head/d)[5]	(dry Mt/yr)[6]
Canada	1096	0.756	0.0302	621725	0.0252	4.861
Ontario	305	0.756	0.0084	202285	0.0252	1.582

TABLE 4C: CANADIAN AND ONTARIAN PRODUCTION OF TURKEY MANURE

Region	Turkey		
	Number[4]	Manure Production	
	(x1000head)	(kg dry/head/d)[5]	(dry Mt/yr)[6]
Canada	21171	0.0101	0.0663
Ontario	8939	0.0101	0.028

Legend:

1 Statistics Canada. 2007b. Cattle Statistics 2007. Catalogue no. 23-012-XIE, Vol. 6, No. 2

2 Statistics Canada. 2007c. Hog Statistics 2007, Vol 6, No 4. Catalogue no. 23-010-XIE

3 Statistics Canada. 2008. Sheep Statistics 2007, Vol 7, No 1. Catalogue no. 23-011-X

4 Statistics Canada. 2007d. Poultry and Egg Statistics, July to September 2007. Catalogue no. 23-015-X, vol. 4, no. 3

5 Klass, Donald, L. 1998. Biomass for renewable energy, fuels and chemicals. Academic Press, USA.

6 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%), Chicken (85%) and Turkey (85%) (Ralevic and Layzell, 2006)

TABLE 5: TOTAL MANURE AMOUNT GENERATED IN ONTARIO[45]

Region	Total Manure[7] (dry Mt/yr)
Canada	**14.209**
Alberta	3.505
Ontario	**3.108**
Quebec	2.615
Saskatchewan	1.871
Manitoba	1.394
British Columbia	1.139
Nova Scotia	0.231
New Brunswick	0.193
Prince Edward Island	0.058
Newfoundland and Labrador	0.006

Legend:

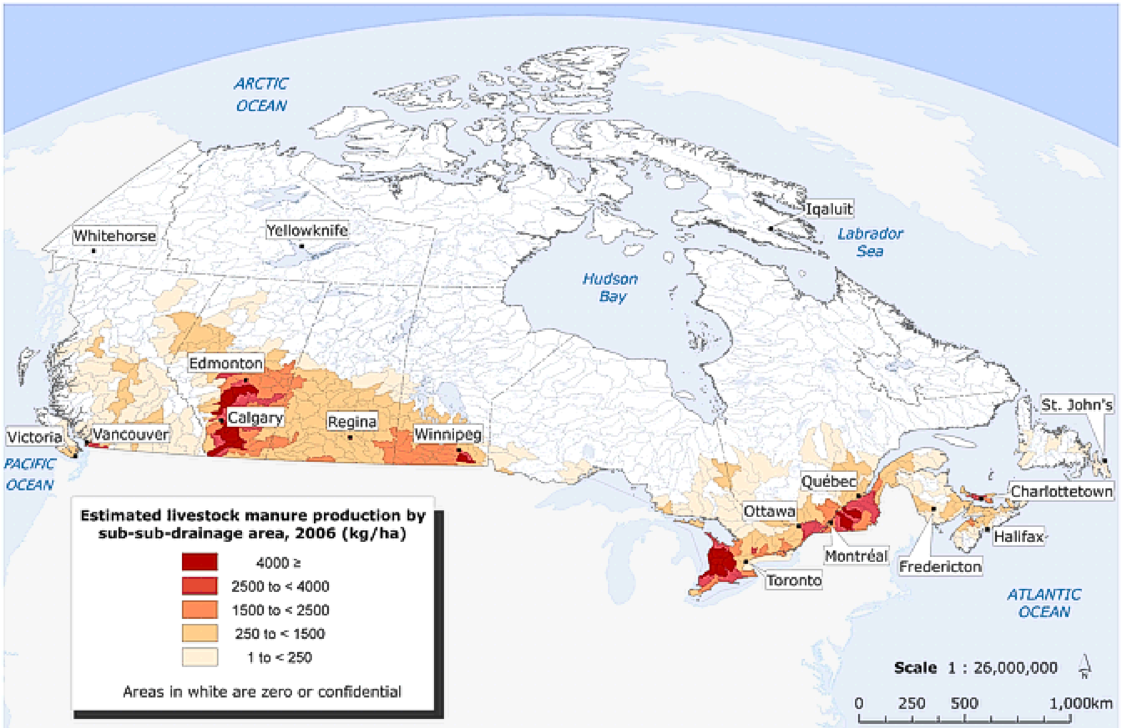
7 Calculated as the sum of all manures (cattle, hogs, sheep, chicken and turkey)

The final result of manure generated amount in Ontario - according to calculation using the number of animal populations and their average rate of manure production - make Ontario the Canadian Province with the second most important potential of biogas production. Almost a quarter of total Canadian manure comes from Ontario fields (3.108 Mt of manure).

The following figure from Statistics Canada shows the geographical repartition of livestock manure produced in Canada. As in Quebec and Alberta, Ontario has some areas with a density of more than 4000 kg of manure per hectare. The majority of the manure production is located in the southern Ontario region.

[45] Considering cattle, hogs, sheeps, chickens, turkeys

FIGURE 1: LIVESTOCK MANURE PRODUCTION IN CANADA, 2006



Source(s): Agriculture and Agri-Food Canada and Statistics Canada, Customized tabulations, Census of Agriculture, Census Geographic Component Base 2006. http://www.statcan.gc.ca/pub/16-002-x/2008004/article/10751-eng.htm

4.1.3 SUMMARY OF TOTAL ON-FARM RAW MATERIAL

According to both the figure 1 - which indicates the spatial repartition of manure in Canada - and the detailed list of crop residues produced per county (section 4.3), we can conclude the majority of on-farm raw material (manure and crop residues) is located Southern and Western Ontario. Among those two regions, the counties with more important raw material are: Bruce, Chatham-Ken, Elgin, Grey, Hutton, Lambton, Middlesex, Oxford, Perth, Waterloo, and Wellington.

Source	Manure	Crop Residues
Volume	3108 dry kt/yr	From 3123 to 4720 kt/yr

4.1.4 Co-Digestion

Since anaerobic digestion is a biological process of organic material decomposition, biomethane can be generated from a wide range of mixed organic residues (referred to as "co-digestion"). Co-digestion is the biogas process using two or more different feedstocks in a digester. Anaerobic digester technology providers have adapted to the co-digestion opportunities and offer flexibility in terms of input types: on-site organic farm waste and industrial, commercial, and institutional waste streams from agri-food processing plants, slaughterhouses, schools and hospitals[46].

The advantage of co-digestion is the possible addition of amendments to specific feedstock to enhance the yield of biological reactions involved in the biodigestion, primarily the methane generation phase (methanogenesis). The addition of co-substrate aims mainly to improve the carbon to nitrogen balance during the AD process, thus making the biochemical conditions more efficient in terms of biogas production. The stoichiometric ratio, which can be defined as the balance in terms mole[47]s of the molecules involved in a chemical reaction, is by the same time improved.

Co-digestion not only improves the yield of biogas production but also the flow qualities of the co-digested substrates used for soiling farm fields. A research involving Guelph University and The Ontario Rural Wastewater Center: «*Anaerobic Digestion of Manure with Various Co-substrates*[48]» brings more specific information on the subject and presents useful results of co-digestion experimentations.

Agri-Food Residues

Residues coming from the agri-food industry also represents significant volumes that need to be considered when planning an anaerobic digestion project. OMAFRA (2005) estimates the food and beverage processing sector in Ontario to a $ 32.5 billion industry. Ontario local farm outputs generated an estimate of $22 billion in gross economic stimulus in 2009 with a net value of $10.7 billion[49]. The generation of organic wastes from agri-food industries is as considerable as the agricultural activities scales and other related operations.

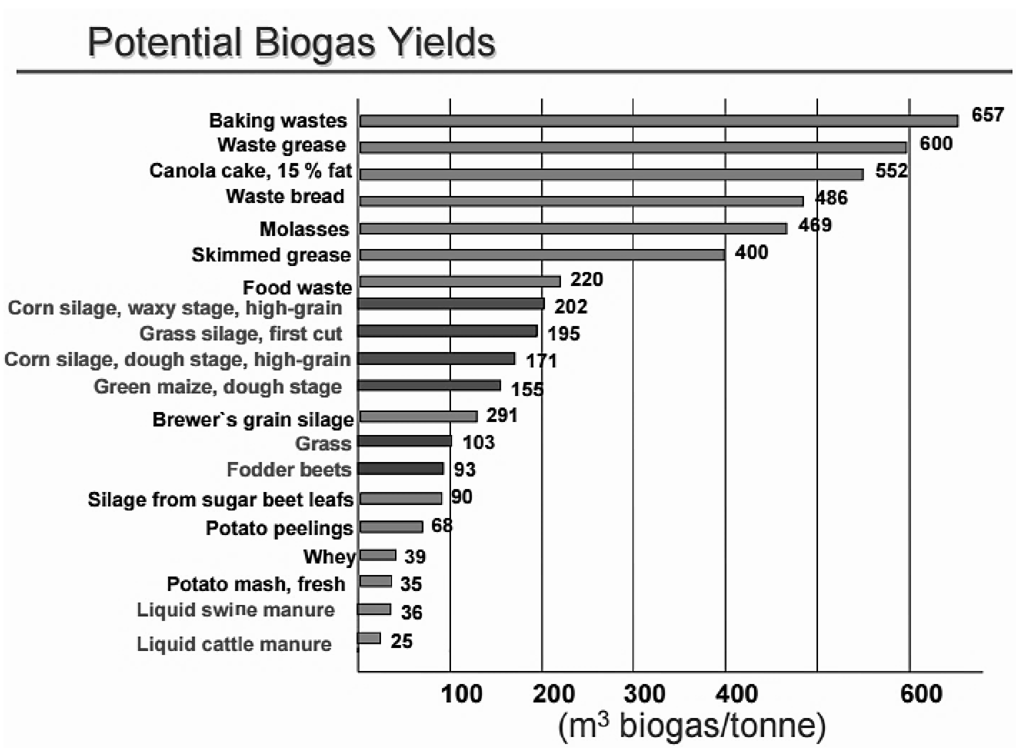
Their composition is complementary to agricultural residues and their associated biogas generation potential (m^3/tonne) is significant and often higher than manure and crop residues.

46 http://www.fpac.ca/wp-content/uploads/2014_CanBio_Report.pdf
47The SI unit of amount of substance
48 http://www.orwc.uoguelph.ca/Research/documents/Research%20Notes_Biogas%20Yields.pdf
49 http://ofa.on.ca/uploads/userfiles/files/agriculture's%20key%20priorities.pdf

However, the technical interest and feasibility of processing biogas from those residues are industry-specific and residue-specific. According to the type of agri-food organic waste used, the yield of biogas (in terms of methane production) varies significantly. Once known, the interest of the feedstock in terms of biogas generation potential (m^3/tonne) has to be combined with quantity available (tonnes) at a reasonable distance, in order to estimate the project potential (m^3/yr).

To illustrate that variability, the figure below shows various agri-food by-products and their respective potential biogas yields. Through several experimental tests, Fleming & MacAlpine from University of Guelph in collaboration with Todd & Hilborn (OMAFRA) have estimated the potential biogas yields for several agri-food waste input. Details of the study are available at the GTM Conference Website[50]. This information is key, as it allows predicting the biogas quantity expected, according to the digester feedstock used. Moreover, potential biogas yields per waste type allows for prioritizing among several types of co-inputs (manure, crop residues, agri-food processing residues, etc.) available in a given area.

Figure 2: Biogas production rate for different raw materialS



[50] Fleming, MacAlpine, Todd, Hilborn. *Energy from waste on Energy from waste on Ontario farms Ontario farms–examining examining the potentia*l [Online] www.gtmconference.ca/site/index.php/2014-presentations/doc_download/73-b2d-2-fleming+&cd=1&hl=fr&ct=clnk&gl=ca

Those results allow the identification of the most interesting agri-food residues in terms of biogas yield (m^3/tonne). With a rate of 657 m^3/tonne, baking waste lead the rows, followed by waste grease (600 m^3/tonne), canola cake (552 m^3/tonne) and waste bread (486 m^3/tonne). Liquid swine manure and cattle manure are the lowest with respectively 36 m^3 and 25 m^3/tonne. The difference between the first and the last input type is approximately 1/25. This important difference shows that for biogas production, it is crucial to consider not only the volume of raw material but also its nature (composition) and its associated potential biogas yield (m^3/tonne).

OTHER CO-DIGESTION FEEDSTOCKS

Across Canada, the number biogas systems in operation have deeply increased, over the last six years, correlated with two major aspects: the available technology and the raw material availability. According to 2012 Canadian Bioenergy data survey, 43 biogas systems in operation were identified in Canada while 2013 data survey identified 77 biogas systems (including 37 in Ontario) for a total capacity of 27,223 kWh. A focus on this second aspect done by Canadian Gas Association and Alberta's council specialists described off-farm material trough categories as follows: municipal solid wastes (MSW), wastewater, Biosolids and Landfills.

MSW are more likely to be mixed with agricultural waste and are easier to collect than other types of off-farm materials that require costly and long pre-treatments. MSW residues are made up of wastes collected from residential areas (households), industrial and commercial and institutional (ICI) wastes, as well as construction and demolition (CD) wastes[51]. However only a portion of the MSW is effectively available for anaerobic digestion. The availability for AD will depend on several metrics: composition, storage conditions (landfill), contamination, etc. A detailed analysis per region is necessary in order to capture the volume of MSW actually available for co-digestion.

Table 6 provides a few numbers on MSW production. It shows that Ontario made up approximatively 40% of the total Canadian MSW with 9646 kt/year, followed by Quebec with the quarter of the total. This confers to Ontario biogas industry an important reserve of co-feedstocks for AD.

[51]http://www.biogasassociation.ca/bioExp/images/uploads/documents/2010/Potential_Production_of_Methane_from_Canadian_Wastes-ARC_FINAL_Report-Sept_23_2010.doc

TABLE 6: ANNUAL CANADIAN MUNICIPAL SOLID WASTE (MSW) PRODUCTION

Region	Waste Disposal[1]				MSW Organic Fraction Subject to AD[2]
	Residential	Industrial, Commercial & Institutional	Construction & Demolition	Total	
	(kt/yr)				(dry kt/yr)
BC	937	1347	461	2745	82
QC	2876	2261	407	5544	252
ON	3438	5193	1014	9646	301
Canada	9455	11564	2817	23836	827

1 Statistics Canada. 2005. This is the difference between waste generated and already 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 waste contains 35% solids)

The various types of co-digestion feedstock have very different composition and require different treatment. The following table summarizes the main advantages and disadvantages of the main feedstock types, including manure and agri-food residues.

TABLE 7: LIST OF PROPERTIES (ADVANTAGES & DISADVANTAGES) OF MAIN AD FEEDSTOCKS

Feedstock	Advantages	Disadvantages
Dairy Manure	• Balanced carbon/nitrogen ratio • Liquid slurry manure collection process simplifies AD adaptation	• Low energy value per tonne of raw material • May contain antibiotics/disinfectants • Low energy content may increase the need for larger digestion tanks
Beef manure	• Balanced carbon/nitrogen ratio • Potentially large volumes of manure available at individual locations (at feedlots)	• Likely to contain more sand, silt, and mud, creating a need for separation technology or periodic shutdowns to clean out tanks. • Animals are commonly out to pasture, only possible at feedlots
Chicken Manure	• High energy value per tonne relative to other manure sources • Relatively simple manure collection Process	• High levels of ammonia can have inhibitory effect on digestion • May require composting first • May contain antibiotics/disinfectants • May contain sand and grit
Hog Manure	• Typical flush manure collection process less suited to AD	• High levels of nitrogen relative to cow manure

COOP CARBONE

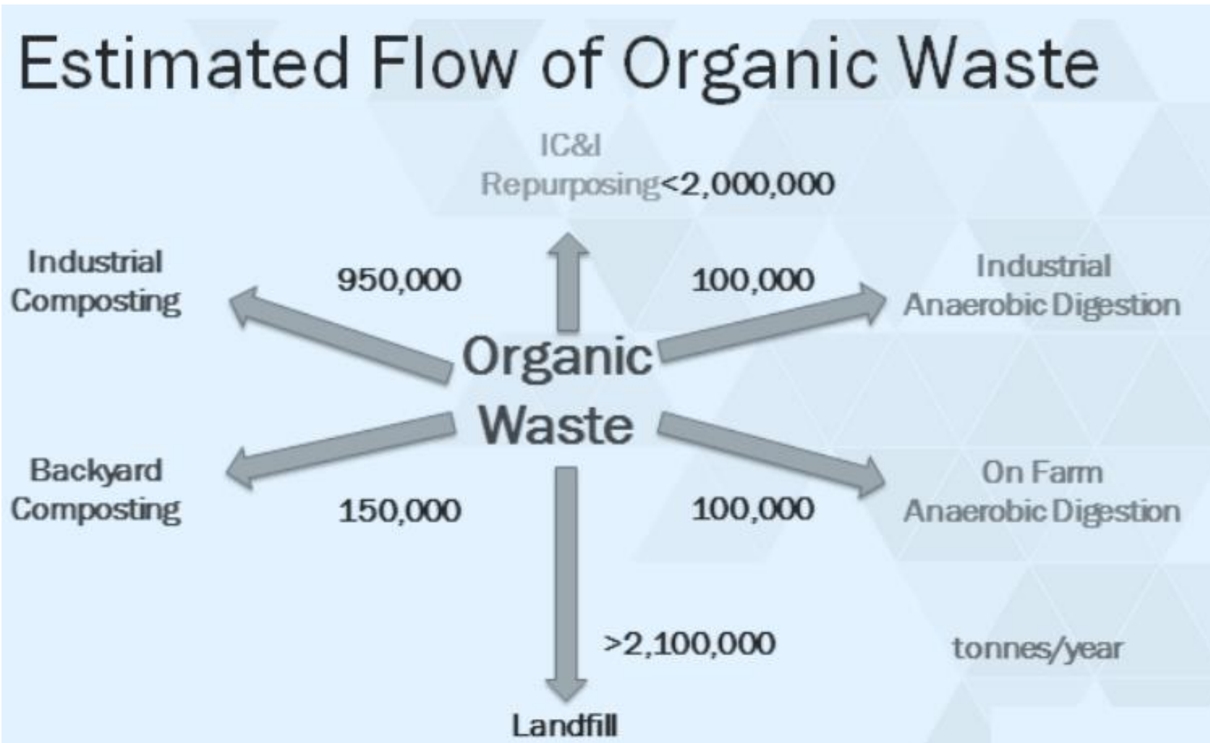
Feedstock	Advantages	Disadvantages
	adaptation • Higher energy content than dairy manure	• May contain antibiotics/disinfectants
Food waste (industrial, commercial, institutional)	• Higher energy value than manure • May have fewer contaminants than • residential organic waste	• Biogas output varies greatly from one source to another • May require sorting and additional capital costs • Requires pasteurization before digestion • Potentially high acid or protein concentrations, which may require additional pretreatment
Fats, Oils & Greases (FOG)	• Very high energy value if concentrated • Relatively easy to manage, if pre-filtered to remove trash, as it comes in liquid form and does not require sorting	• May require pasteurization before digestion • Long-term supply constraints are likely an issue • High levels of volatile fatty acids (VFA) can inhibit digestion • Variability in quality can impact digestion
Bakery waste	• High energy value per tonne	• Limited availability
Slaughter-house waste	• High energy value	• May contain pathogens, requiring pasteurization before digestion • High levels of volatile fatty acids can inhibit digestion • High protein levels may cause foaming and inhibit digestion • Offensive odour may require special management of raw and digested material

Sources: Jake DeBruyn P.Eng OMAFRA. Anaerobic Digestion: Ontario Provincial Initiatives, May 2015 [online] http://www.foodandfarming.ca/wordpress/wpcontent/uploads/2015/06/Jake-DeBruyn-OMAFRA.pdf

4.1.5 Summary of Available Organic Waste

The overall flux of Ontario organic waste are summarized through the Figure 3 by Jake DeBruyn P. Eng. (OMAFRA, 2015).

Figure 3: Overview of Ontario organic waste flow (tonnes/year)



Source: http://www.foodandfarming.ca/wordpress/wp-content/uploads/2015/06/Jake-DeBruyn-OMAFRA.pdf+

As shown, the majority of the waste goes to landfills, estimated over 2 million tonnes per year in Ontario, 10 times more than industrial and on-farm anaerobic digestion (100 kt each). Organic waste redirected to on-farm anaerobic digesters makes up only 100 000 tonnes per year, which covers about 2% of total organic waste generation in Ontario. Given that low percentage, it can be assumed that an important potential remains additional on-farm AD projects.

However potential development of new on-farm anaerobic digesters is highly dependent on the possibility of digesting off-farm materials, which significantly increases the biogas yields and hence the economic feasibility of the projects. The possibility of injecting non-agricultural wastes to anaerobic digesters greatly contributes to the economic viability of biodigestion projects that would otherwise be non-viable. Many projects, with a net present value (NPV[52]) previously negative, have turned economically viable with off-farm materials.

For example, Jake DeBruyn P.Eng (OMAFRA, 2015) reported the NPV for a biodigestion project on a typical Ontario dairy farm of 85 milking cows[53], with two different levels of off-farm material.

- 25% off-farm material (1300 m^3/yr), mid strength vegetative waste, $10/tonne tipping fee, 57 kW capacity, negative NPV
- 50% off-farm material (same material), 100 kW, positive NPV

The same conclusion applies to basically any types of farm in any province in Canada. In British Columbia, the allowed percentage by the Ministry of Environment of non-agricultural feedstocks is as important as the former Ontario regulation, which is 25%. According to this regulatory over on-farm AD feedstock, a study[54] made by CH-Four Biogas Inc.'s engineers, an anaerobic digester technology provider, and prepared for B.C. Agricultural Research and Development Corporation, came to the following statement:

"The potential number of economically viable AD systems in B.C. is restricted to a very small number of sites that have an ideal combination of farm size, distance from interconnection and proximity/access to highly desirable feedstocks. If MOE's proposed *On-farm AD Waste Discharge Authorization* were changed to enable on-farm AD systems to meet the requirements for accepting 49% non-agricultural feedstocks, the number of economically viable sites in B.C. would increase dramatically."

On October 25, 2013, the Ontario government filed amendments to regulation O. Reg.267/03 to enhance the anaerobic digestion approval program under the Nutrient Management Act (NMA), with one key change: facilities can now treat up to 50% off-farm materials under the Regulated Mixed Anaerobic Digestion Facility program. However, even considering the new regulation that allows up to 50% off-farm material, agriculture may remain the main source of organic feedstock for biogas production. Off-farm material utilization for biodigestion projects may be limited, due to the alternative existing uses of food waste for various and more profitable valorization routes.

[52] Represent the actual value of the total of incomes deducted from spending related to the project over its timeline
[53] http://www.foodandfarming.ca/wordpress/wp-content/uploads/2015/06/Jake-DeBruyn-OMAFRA.pdf
[54] British Columbia On-Farm Anaerobic Digestion Benchmark Study

4.2 POTENTIAL FOR AGRICULTURAL BIOGAS PROJECTS IN ONTARIO

4.2.1 POTENTIAL BIOGAS GENERATION BASED ON AGRICULTURAL SOURCES

The on-farm potential methane production is summarized in the following tables, considering crop residues, manure and municipal solid wastes, and based on 2005 data from Canadian Gas Association. The estimation of biogas generation from crop residues assumes that only 20% of the material is amenable to digestion and that an average of 300 Mm^3 CH_4/dry Mt of residues is produced (Wiese and Kujawski, 2007). A great part of the methane production from crop comes from Ontario: 20 % (0.19 over 1.05 Mt/yr) of Canadian production.

TABLE 8: POTENTIAL METHANE PRODUCTION FROM CANADIAN CROP RESIDUES

Region	Removable Residue[1] (kt dry/yr)	Methane AD[2] (Mt/yr)
Canada	25787.98	1.0521
Ontario	4724.53	0.1928

1 Calculated as the sum of all crop production

2 Calculated as crop residues (dry kt/yr)x10-3 (Mt/kt)x0.2x 300 (Mm^3 CH_4/Mt dry) x 0.00068 (Mt CH_4/Mm^3 CH_4). (Wiese and Kujawski, 2007). Assume that only 0.2 (20%) of the crop residue is amenable to AD.

In the following table, the potential for methane generation from available manure residues is shown, assuming that an average of 250 Mm^3 CH_4/dry Mt of manure is produced (Electrigaz, 2007). The largest amounts of potentially available manures and potential RNG produced are in Ontario and Quebec (large hog and chicken numbers). The Ontarian potential for methane generation still remains the largest part of the national potential, with an estimate of 0.26 Mt/yr over 1.18 Mt/yr, thus representing 22% of the total Canadian potential.

TABLE 9: POTENTIAL METHANE PRODUCTION FROM CANADIAN MANURES

Region	Total Manure[1] (dry Mt/yr)	Methane AD[2] (Mt/yr)
Canada	14.209	1.188
Ontario	3.108	0.26

1 Calculated as the sum of all manures (cattle, hogs, sheep, chicken and turkey)

2 Calculated as total manure (dry Mt/yr) x 250 (Mm^3 CH_4/Mt dry manure) x 0.00068 (Mt CH_4/Mm^3 CH_4) (Electrigaz, 2007)

4.2.2 POTENTIAL BIOGAS GENERATION BASED ON FOOD WASTE AND OTHER SOURCES

It is estimated that only 25% of the household wastes are amenable to anaerobic digestion (Ostrem, 2004). None of the other wastes were considered to contain significant amounts of digestible wastes. This assumption is conservative, as it underestimates the effective volume of digestible waste by neglecting the amount of food wastes disposed of from restaurants and institutional cafeteria.

TABLE 10: ANNUAL METHANE PRODUCTION FROM CANADIAN MUNICIPAL SOLID WASTES (2005)

Region	Methane AD[1] (kt/yr)	Region	Methane AD[1] (kt/yr)
Canada	96.76	**MB**	4.22
ON	35.19	**SK**	2.85
QC	29.43	**NL**	2.21
BC	9.59	**NB**	2.08
AB	8.87	**NS**	1.74

1 Calculated as Column 6 (Table 7) (dry kt /yr) x 103 (dry t/kt) 172 (m^3 CH_4)/(t dry) x 0.00068 (t CH_4/m^3 CH_4) x 10-3 (kt CH4/t CH_4). (Ostrem, 2004)

4.2.3 Total Potential of biogas potential

This last table shows a wider classification of potential methane generation from Canadian waste by province and waste type.

Table 11: Potential Methane Production from Canadian Wastes

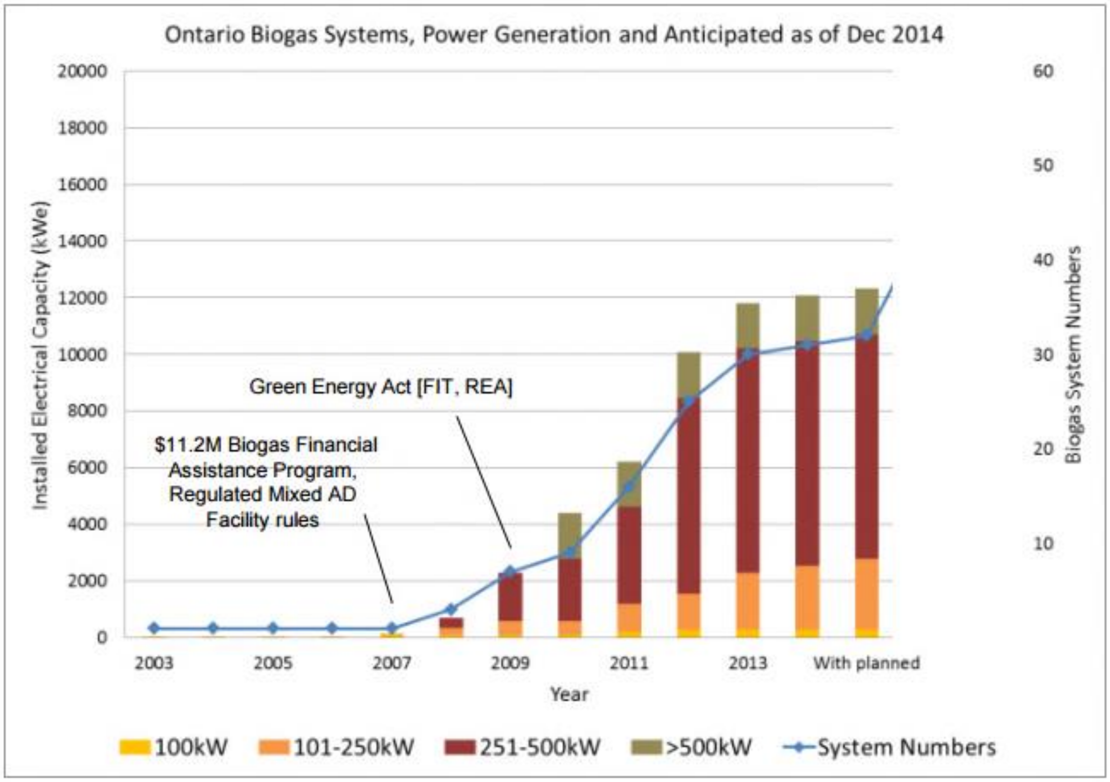
Region	Agriculture Wastes		Municipal Wastes	Total
	Manure	Crops	MSW	
	Mt/yr			
NL	0[55]	0	0.002	0.002
PE	0.005	0.003		0.008
NB	0.016	0.002	0.002	0.02
NS	0.019	0.001	0.002	0.022
BC	0.095	0.005	0.01	0.11
MB	0.117	0.143	0.004	0.264
QC	0.219	0.096	0.029	0.344
ON	**0.26**	**0.193**	**0.035**	**0.488**
SK	0.156	0.346	0.003	0.505
AB	0.293	0.263	0.009	0.565
Canada	1.188	1.052	0.097	2.337

4.2.4 Existing Biogas Production

In the following figure, all the biogas systems operating in Ontario are grouped and sorted by the characteristics of their electrical nominal capacity. This overview provides an indication and illustrates the main characteristics of existing facilities related to on-farm biogas production in Ontario.

[55] Quantity not available or non-significant

FIGURE 4: EVOLUTION OF ONTARIO BIOGAS SYSTEM AND CAPACITY (2003-2014)



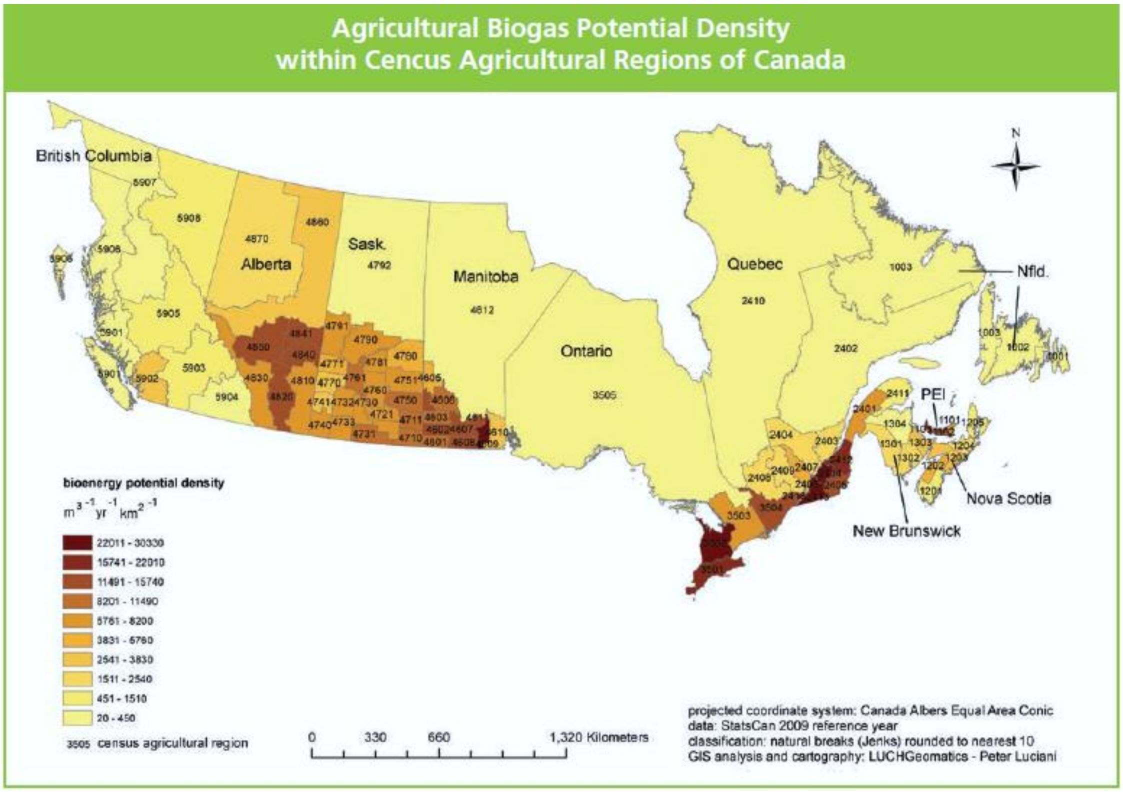
Based on the previous estimation of Ontario biogas potential, we denote almost 40 plants producing biogas at the beginning of 2015. A total of 12000 kW were inventoried as all facilities are taken into account. This consists of an equivalent of approximately 1128 m³ of biogas per year[56].

4.3 LIST OF POTENTIAL GROUPED PROJECTS, PER GEOGRAPHICAL AREA

In Ontario, the 2011 census of agriculture stated that there is a total of approximately 51,950[57] farms for over 12,668,236 acres areas. The next two figures show, for Canada, areas with wide potential of biogas and favourable for biogas projects implantation. The figures show that many additional biogas projects can be implemented for the benefit of farmers (generation of new revenues) and society (environmental benefits). Considering the availability of raw material as the a key criterion, it appears that the most interesting geographical area to implement biogas projects are the high density zones. A darker zone represents areas with more on-farm raw material. Considering this criterion, it can be assumed Western Ontario has the most suitable dispositions for additional biogas projects. Then comes Eastern Ontario, followed by central Ontario.

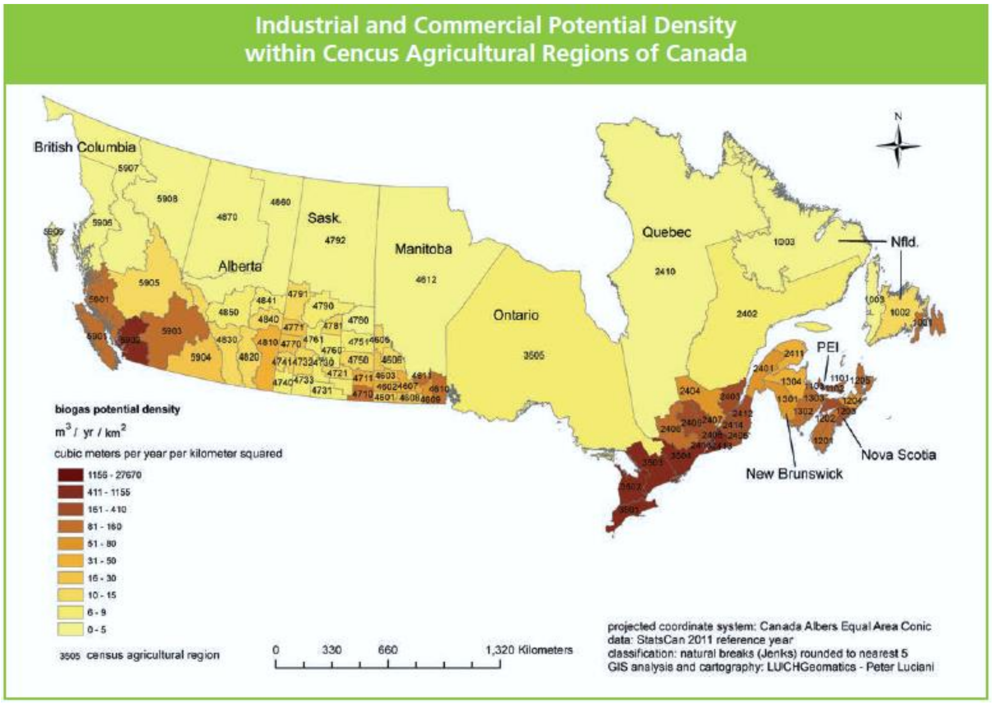
[56] Considering 1 m³ of purified biogas = 10.639 kWh (6 kWh at 60% methane)
[57] http://www.omafra.gov.on.ca/english/stats/census/summary.htm

FIGURE 5: GENERATION OF ON-FARM AD IN CANADA (2009)



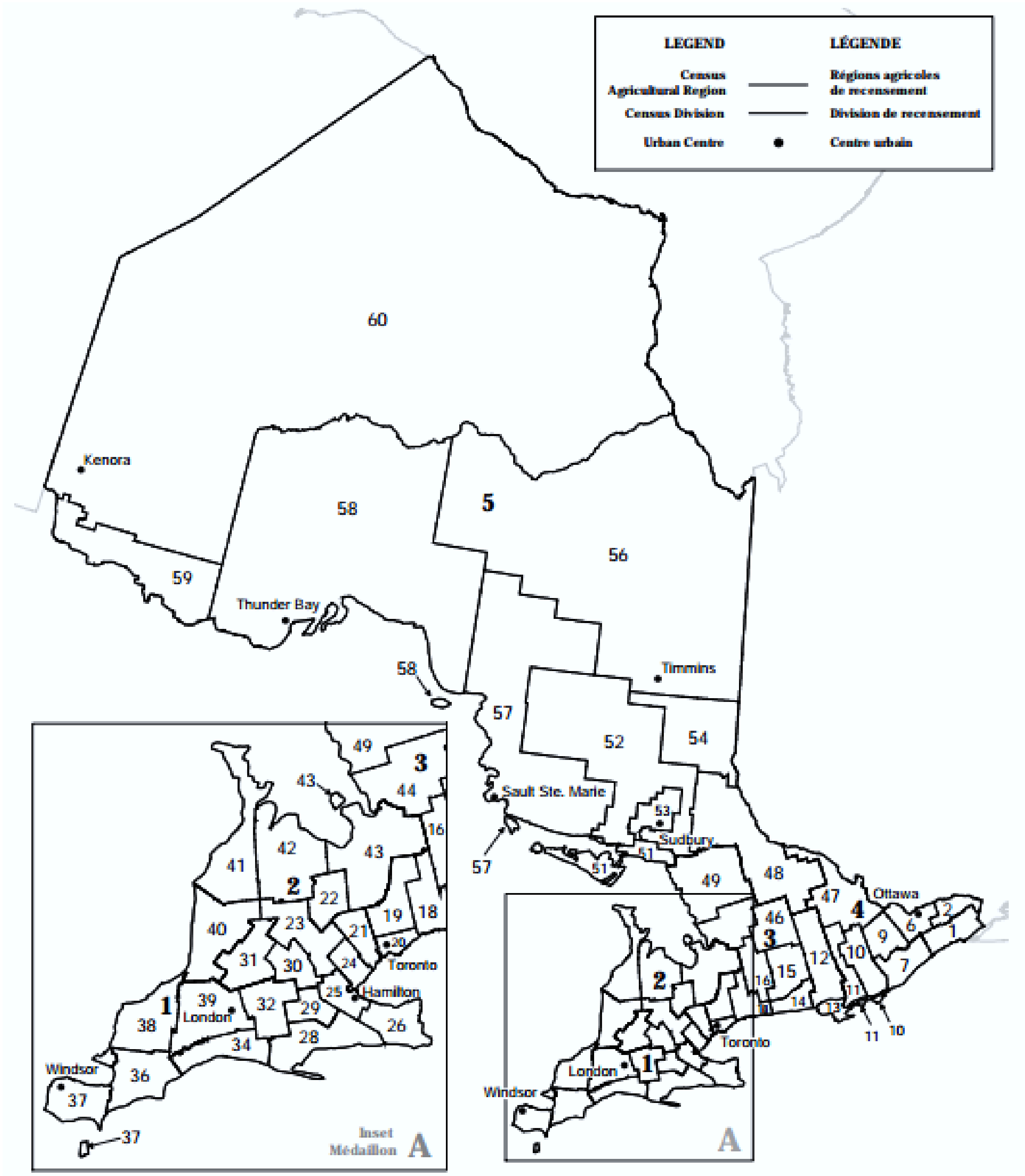
Regarding the food waste, industrial and other commercial organic waste - which can feed anaerobic digesters up to 50% of total input - the following map indicates the areas with the most concentrated volumes of organic material. Southern, Central and Eastern still remains with a lot of potential densities. It is also important to mention that, those raw materials could be subject to transportation to the on-site anaerobic digester, in return to some related fees.

FIGURE 6: GENERATION OF OFF-FARM AD RAW MATERIAL IN CANADA (2009)



A good indication of the localisation of high biogas potential areas from those two previous maps is provided through the agricultural census region in Ontario on the figure 7. An interpretation of data shows that in localities of Dufferin, Grey and Simcoe for example, agricultural bioenergy potential density is between 22,011 to 30,330 m^3 per km^2 over one year. Total superficies times average potential density equates the total biogas potential in concerned area. A region holding a high amount of manure, crop residues or other off-farm raw material (household organic waste) is likely to be favourable for grouped project of biogas, since the key criterion (AD feedstocks supply) is met. As opposed to individual projects, grouped projects allow for the reduction of fixed and operating costs, which allows the valorisation of organic waste that otherwise would have been not feasible.

FIGURE 7: AGRICULTURAL CENSUS REGION IN ONTARIO



Source:
http://www.ofa.on.ca/uploads/userfiles/files/biomass_crop_residues_availability_for_bioprocessing_final_oct_2_2012.pdf

County / Division / District / Municipality				
Southern Ontario	**Western Ontario**	**Central Ontario**	**Eastern Ontario**	**Northern Ontario**
Brant (29)	Bruce (41)	Durham (18)	Frontenac (10)	Algoma (57)
Chatham-Kent (36)	Dufferin (22)	Haliburton (46)	Lanark (9)	Cochrane (56)
Elgin (34)	Grey (42)	Hastings (12)	Leeds & Grenville (7)	Greater Sudbury (53)
Essex (37)	Halton (24)	Kawartha Lakes (16)	Lennox & Addington (11)	Kenora (60)
Haldimand-Norfolk (28)	Huron (40)	Muskoka (44)	Ottawa (6)	Manitoulin (51)
Hamilton (25)	Peel (21)	Northumberland (14)	Prescott & Russell (2)	Nipissing (48)
Lambton (38)	Perth (31)	Parry Sound (49)	Renfrew (47)	Rainy River (59)
Middlesex (39)	Simcoe (43)	Peterborough (15)	Stormont, Dundas & Glengarry (1)	Sudbury (52)
Niagara (26)	Waterloo (30)	Prince Edward (13)		Thunder Bay (58)
Oxford (32)	Wellington (23)	York (19)		Timiskaming (54)

Note: Number in the bracket next to county/division/district/municipality refers to the region on the map (Figure 7).

A detailed repartition of crop residues in Ontario is represented in the following table. The amounts of residues are identified per county. When assessing the possible inputs, from harvestable residues of AD activities in a county, the proximity and common management of waste by some operator make possible the consideration of residues generated in the neighbouring counties. The radius of collection for such inputs could be set up to 100 km by means of transportation. As highlighted in this table, it appears that areas with the most biogas potential with crop residues are the following: Middlesex, Huron, Perth, Wellington & Elgin, with over 500 kt per year of residue. All those areas are located in Western and Southern Ontario regions.

Table 12: Summary of Sustainably Harvestable Crop Residues in Ontario

#	County	Total Harvestable Residue in the County ('000 tonne)	Total Harvestable Residues in the County and Neighbouring Counties ('000 tonne)*	Name of Neighbouring Counties (sharing borders)
1	Algoma	12.8	28.1	Cochrane,Thunder Bay
2	Brant	42	362.2	Haldimand, Hamilton, Norfolk, Oxford, Waterloo
3	Bruce	178.4	756.7	Grey, Huron, Wellington
4	Chatham-Kent	189.3	636.8	Elgin, Essex, Lambton, Middlesex
5	Cochrane	7	35.7	Algoma, Thunder Bay, Timiskaming
6	Dufferin	36.7	423	Grey, Peel, Simcoe, Wellington
7	Durham	102.4	382.2	Kawartha Lakes, Northumberland, Peterborough, Simcoe, York
8	Elgin	140.4	855.4	Chatham-Kent, Middlesex, Norfolk, Oxford
9	Essex	-45.7	143.6	Chatham-Kent
10	Frontenac	20.8	221	Lanark, Leeds & Grenville, Lnnx & Addgton, Renfrew
11	Grey	115.6	589.3	Bruce, Dufferin, Simcoe, Wellington
12	Haldimand	-43.4	-10.3	Brant, Hamilton, Niagara, Norfolk
13	Halton	10.4	201.4	Hamilton, Peel, Wellington
14	Hamilton	9.3	244.6	Brant, Haldimand, Halton, Niagara, Waterloo, Wellington
15	Hastings	53.6	239.9	Lnnx & Addgton, Northumberland, Peterborough, Prince Edward
16	Huron	293.1	1240.4	Bruce, Lambton, Middlesex, Perth, Wellington
17	Kawartha	54.4	196.2	Durham, Peterborough

#	County	Total Harvestable Residue in the County ('000 tonne)	Total Harvestable Residues in the County and Neighbouring Counties ('000 tonne)*	Name of Neighbouring Counties (sharing borders)
18	Lambton	77.4	835.1	Chatham-Kent, Huron, Middlesex
19	Lanark	25.6	246.6	Frontenac, Leeds & Grenville, Ottawa, Renfrew
20	Leeds & Greenville	43.3	331.5	Frontenac, Lanark, Ottawa, Stor, Dun & Glen'y
21	Lennox & Addington	34.5	151.5	Frontenac, Hastings, Prince Edward
22	Middlesex	275.3	1443.5	Chatham-Kent, Elgin, Huron, Lambton, Oxford, Perth
23	Niagara	-47.3	-81.4	Haldimand, Hamilton
24	Norfolk	29	389.3	Brant, Elgin, Haldimand, Oxford
25	Northumberland	69.9	307.9	Durham, Hastings, Peterborough, Prince Edward
26	Ottawa	60	498.5	Lanark, Leeds & Grenville, Prescott & Russel, Renfrew, Stor, Dun & Glen'y
27	Oxford	221.3	1058.7	Brant, Elgin, Middlesex, Norfolk, Perth, Waterloo
28	Peel	12.1	344.8	Dufferin, Halton, Simcoe, Wellington, York
29	Perth	246.6	1309.9	Huron, Middlesex, Oxford, Waterloo, Wellington
30	Peterborough	39.4	319.8	Durham, Hastings, Kawartha Lakes, Northumberland
31	Prescott & Russel	91	332.8	Ottawa, Stor, Dun & Glen'y
32	Prince Edward	42.5	200.6	Hastings, Lnnx & Addgton, Northumberland
33	Rainy River	41	49.3	Thunder Bay
34	Renfrew	96.8	203.3	Frontenac, Lanark, Ottawa
35	Simcoe	88.9	382.9	Dufferin, Durham, Grey, Peel, York

#	County	Total Harvestable Residue in the County ('000 tonne)	Total Harvestable Residues in the County and Neighbouring Counties ('000 tonne)*	Name of Neighbouring Counties (sharing borders)
36	Stormont, Dundas & Glengarry	181.7	376.1	Leeds & Grenville, Ottawa, Prescott & Russel
37	Thunder Bay	8.2	69.1	Algoma, Cochrane, Rainy River
38	Timiskaming	7.6	14.6	Cochrane
39	Waterloo	104	792.9	Brant, Hamilton, Oxford, Perth, Wellington
40	Wellington	169.6	1175.9	Bruce, Dufferin, Grey, Halton, Hamilton, Huron, Peel, Perth, Waterloo
41	York	27.1	230.6	Durham, Peel, Simcoe
Southern Ontario		847.7		
Sub-total Western Ontario)		1,255.50		
Sub-total (Central Ontario)		389.3		
Sub-total (Eastern Ontario)		553.8		
Sub-total (Northern Ontario)		76.7		
Grand Total		3,213.10		

Source: http://www.ofa.on.ca/uploads/userfiles/files/biomass_crop_residues_availability_for_bioprocessing_final_oct_2_2012.pdf

5. Cost & Benefits Estimation

5.1 Estimation of potential costs

The use of anaerobic digesters for waste management purposes is an innovative practice in the agricultural sector. Processing organic wastes through the production chain increases viability of farming operations and aim to a better optimisation of resources. Agricultural efficiency is possible to be increased by two main ways: the maximization of production and the minimisation of costs. Biogas projects allow for the production of energy associated with low-cost input (organic waste). With this perspective comes the need to evaluate the possible costs associated with the establishment of an agricultural biogas facility.

There are several types of anaerobic digesters with different capacities and technical specifications (e.g. wet versus dry inputs). Many financial analysis studies can be retrieved from the literature and present typical financial indicators such as NPV, internal rate of return (IRR), payback period, etc. However they are modeled based on specific case studies, hence the economic viability is shown as highly project-specific. From one project to another, the viability of an on-farm AD plant increases as its input capacity does so. This is due to economies of scale associated with investment (CAPEX) and operating costs (OPEX), as well as access to larger volume of waste at a lower cost. In order to make the cost analysis applicable to any type and scale of project, it is useful to express costs and financial parameters per unit of input digested or per unit of output generated (electricity in kWh or biogas in m^3).

In order to evaluate anaerobic digester costs applicable to a wide range of capacity, a very practical calculation tool has been developed by Don Hilborn. It consists in a spreadsheet named “Agricultural Anaerobic Digestion Calculation Spreadsheet” (AADCS). The tool uses anaerobic digestion data inputs and outputs - as well as the associated costs & revenues - as the basis for an AD financial model that allows the evaluation of feasibility for different scales of investments. The tool was developed using OMAFRA’s*,* “Calculations and Information for Sizing Anaerobic Digestion Systems” info sheet. Anaerobic digestion data used in the AADCS were obtained from *Boehni Energis und Umwelt*, a Switzerland-based Energy and Environmental firm contracted by OMAFRA. Livestock manure production and composition estimations were made by OMAFRA’s Manure Storage Sizing Program (MSTOR).

Base model assumptions and financial information provided by the AADCS are integrated in four separate sections: (1) model data inputs, (2) model results outputs, (3) model estimated costs and (4) model estimated revenues.

Capital costS

According to the most typical on-farm AD capacity scale, the AADCS repertories them through four categories: less than 100kWh capacity, 100-200kW, 200-300kW and more than 300kW capacity. The following table illustrates the fees related to those four different categories. The AADCS has incorporated CAPEX values for each category of installed capacity. Those values are then multiplied by the estimated installed capacity (kW), calculated in the anaerobic digester output section, to evaluate capital costs. See Mallon & Weersink (2007), Appendix 1.5, page 84 & 85., for further description of these calculations and derived per kW capital costs.

Capacity scale	[0;100kW]	[100kWh;200kW]	[200kW;300kW]	[>300kW]
Capital costs	$5,740/kW	$5,096/kW	$4,452/kW	$3,477/kW

Annual Costs

The estimation made by the AADCS of annual costs takes into account upstream annual costs such as the cost of transporting livestock manure and off-farm material to the digester. Downstream costs include the annual operation and maintenance costs of the digester.

- Calculation of livestock manure and off-farm material

When estimating the costs associated with the transportation of livestock manure and off-farm material to the digester, the AADCS assumes a transportation cost of $1 and multiplies it by the total amount of livestock manure and off-farm material calculated in the farm output section (See Mallon & Weersink (2007), AADCS Model Results Outputs section, page 25., for further description of these calculations).

- Calculation of digester operation and maintenance costs

The digester operation and maintenance cost are estimated by the AADCS by considering annual cost for the digester, its power generator and other key aspects such as insurance, maintenance on pumps, piping and electrical. The AADCS multiplies these costs per kW with the total installed capacity (kW) of the anaerobic digester. The sum of total annual cost of transportation plus digester operations & maintenance costs results with the total annual cost for the anaerobic digester. More details of these calculations are available through Mallon & Weersink (2007), Appendix 1.7, page 87.

5.2 Estimation of Potential Benefits

The activity of biogas production such as every renewable gas project aims to bring some value to organic matter waste. Limiting the wastes resulting from the generation of an output (biogas) and introducing those wastes into the process is the main pathway of sustainable development. Anaerobic digester project developers can obtain significant benefits from a total self-sustaining system, depending on their capacity of collecting and processing wastes. Anaerobic digestion provides income through the valorization of the biogas generated. Those incomes can be evaluated from two separate sources: methane volume extracted and electricity generated from biogas combustion.

The sum of electricity revenue, manure reduction revenue and off-farm material tipping fee revenue represent the model's estimated revenues held by the AADCS.

In their study, from the base model where only manure is digested, Mallon and Weersink (2007), stated three evaluated scenarios for analysing the economics of an anaerobic digester in Ontario. The first scenario evaluates the productivity and financial impact of increasing generator size and electricity output. The second one assumes that 25% of anaerobic digesters is fed with off-farm organic material (mainly food waste). The third and last scenario explores the case of digesting livestock manure with energy crops.

Electricity Revenues

The calculation of electricity revenues with the AADCS assumes 8000 hrs of operations per year (22 hrs per day). In its initial version, the AADCS calculated electricity split into non-peak electricity output and peak electricity output. Since the publication of the AADCS, major policy and regulatory changes has impacted the electricity tariff, as detailed earlier in Section 2.2. As mentioned, the Ontario's Feed-in Tariff (FIT) Program (2009) offers a guaranteed price schedule for electricity, according to the range scale define by the AADCS.

Capacity scale	[0;100kW]	[100kWh;200kW]	[200kW;250kW]	[250kW>500kW]
Contract price cents/kWh	26.5	21.0	21.0	16.4

To calculate the revenue from AD, the amount of electricity output is multiplied by the contract in force prices related to the category for which it belongs.

Manure reduction revenues

After being processed through an anaerobic digester, organic material is reduced by approximatively 5%. The bacteria consume volatile solids and produce biogas. Besides, manure management in an enclose facility (the biodigester) prevents dilution with rainwater, which represents avoided costs of transportation and soil applications. The volume reduction is evaluated in the AADCS by multiplying the amount of organic material volume. The volume reduction decreases organic material storage and application costs since it has been digested. A ratio of $2 per tonne is assumed for storage and application costs. The value of savings is obtained by multiplying the ratio by the volume reduction. This represents an avoided cost (annual costs), accounted for by the AADCS in the revenue section.

Tipping Fees

Off-farm organic material is another source of revenue taken into account by the AADCS. It is typically a waste product from another food-processing industry. A tipping fee is a fee paid by the supplier of the waste product or off-farm organic material to the receiver of the waste product as compensation for disposing of that waste product. Tipping fees are negotiated between the supplier and receiver of the waste material. Tipping fee values will depend on several market parameters: quality, quantity, location and transportation costs of the waste material. These fees are accounted for by the AADCS as potential revenues.

Total net revenues

In order to expose the results of the financial parameters integrated in the following table (adjusted with the FIT program price), the AADCS is built on a base model with some characteristics and specifications. In the annex section, a detailed description of the base model constructed to evaluate the financial feasibility of such projects, as indicated by the authors. The model uses estimated values from the AADCS (the size of anaerobic digesters, electricity yield, capital costs, annual cost and revenue).

TABLE 13: BASE MODEL ASSUMPTIONS AND FINANCIAL FLUX

	<100kW	100-200 kW	200-300kW	>300kW
Standard offer price electricity	0.265	0.21	0.21	0.164
Farm input				
Livestock Manure(Metrics tonnes/years)				
Total organic material	16606	33258	49864	66470
Anaerobic digester yearly operation time	**16606**	**33258**	**49864**	**66470**
	8000	8000	8000	8000
Anaerobic digestion output				
total electricity output(kWh/year)				
	798884	**1599901**	**2398745**	**3197589**
Anaerobic digester capital costs				
size of AD system				
per kW capital costs ($/kW)	99.9	199.9	299.9	399.9
Total capital costs	5740	5096	4452	3477
	573426	**1018690**	**1335155**	**1390452**
Additional parameters				
Real discount rate (%)				
Investment period (years)	8	8	8	8
Income tax rate	10	10	10	10
Reduction in organic material (%)	30	30	30	30
organic material application costs ($/metric tonne)	5	5	5	5
	2	2	2	2
Financial analysis				
Revenue				
Total electricity revenue				
Manure reduction revenue	211704.26	335979.21	503736.45	524404.6
Total revenu	1661	3326	4986	6647
	213365.26	**339305.21**	**508722.45**	**531051.6**

	<100kW	100-200 kW	200-300kW	>300kW
Expense				
Anaerobic digester annual operation and maintenance costs				
Total expense	33838	67770	101608	135446
	33838	**67770**	**101608**	**135446**
Annual net revenue before tax				
Income tax and depreciation	**179527.26**	**271535.21**	**407114.45**	**395605.6**
Depreciation				
Tax savings	28659	50958	66749	68531
	8597.7	15287.4	20024.7	20559.3
Annual net revenue after tax				
	188124.96	**286822.61**	**427139.15**	**416164.9**
Financial measures				
Payback period (years)				
Simple rate of return (%)				
Net present value ($)				
Internal rate of return (%)				

The results shown in the previous table took electricity into account as AD output. Another production option is the strict production of methane by treatment of biogas obtained. An equivalence of volume of methane can be found through metric relation to an electricity quantity. The calorific power range of 1m³ biogas is 6 to 6.5 kWh, assuming biogas contains around 60% of methane. For example, the biogas's equivalence of the total output production of a 99kW capacity digester, operating 8000hrs per year (22hrs/day) is 133147 m³ of biogas (table 13).

6. CONCLUSION AND RECOMMENDATIONS

As described in this report, the government of Ontario has implemented several economic and regulatory incentives with the aim to accelerate the development of renewable energy in Ontario, including biogas projects in the agricultural sector. OMAFRA has granted farmers and agri-food industries 11.2 millions dollars since 2009 in order to support AD projects through its Biogas Systems Financial Assistance Program (2008-2010). The feed-in tariff program has also supported the development of AD projects in the agricultural sector.

As shown in this report (section 4), there is still a significant potential for additional anaerobic digestion projects in Ontario. Due to the importance of the volume, AD systems are financially viable for the largest farms. For instance, research from the University of Guelph has reported that when no other input material is available other then livestock manure, AD technology is only financially feasible for dairy farms with at least 616 cows on farm. Since the financial viability is very project-specific, a more detailed analysis is needed (for instance per region or county) in order to identify the largest farm that currently don't have AD systems and who could implement AD project in order to increase the province biogas production. The 2 or 3 most interesting regions (including for instance southern Ontario) could be selected in order to concentrate the effort into the most interesting areas.

In combination to a more detailed analysis per region or county, which would allow the identification of the largest farms and most interesting volumes of raw material, a few other criteria must be taken into account when identifying potential projects.

A first new factor to consider as of now is the potential access to the carbon offset market for AD projects. Since Ontario joined the Western Climate Initiative along with California and Quebec and announced an ambitious emission reduction target of – 37% compared to 1990 levels, to be achieved by 2030. In order to achieve that target, all the available emission reductions will have to be harvested. AD projects will have an important role to play, as they allow for the reduction of methane but also produce a renewable energy (biomethane) that can replace fossil fuels such as propane or natural gas.

Once the carbon market in place, it is likely AD projects will be granted offset credits as they allow the reduction of methane emission (each tonne of CH_4 equivalent to 21 tonnes of CO_2). Offset credits are currently commercialized at an average of 8 to 12 CAD/tonne of CO_2. In the current market conditions, the commercialisation of offset credits could increase the revenues from 1 to 2 cents per kWh. A more detailed analysis is recommended, per project, in order to evaluate the accessibility to the carbon market and measure how carbon revenues may impact the financial viability of the projects. During the year 2017, the government of Ontario will work with Quebec Ministry of Environment (MDDELCC) in order to adapt existing offset protocol for 13 types of projects, among which anaerobic digestion projects. Once the protocols published, it will be important for the agricultural sector to analyse the criteria and identify the associated potential for new AD projects.

A second new factor that may impact the feasibility of projects - and therefore the magnitude of the effective potential for new AD projects - is the capacity to develop bundles or grouped projects (also called aggregation), per region or county. As we described in the report, the financial viability of AD projects heavily depends on the size of the projects. The costs in capital and operation rapidly drop with the size of the projects. Moreover, the costs of developing a carbon offset project (costs of quantification, project documentation, external audit, verification and monitoring) are the same regardless of the project size. Another factor to consider is the market leverage allowed by grouping several projects together. Electricity power purchase agreements, as well as heat or biomethane commercialisation contracts, are easier to negotiate with larger volumes, as it decreases the risks for the buyer.

Having this in mind, it is crucial to explore innovative business models and develop partnerships in order develop bundle projects per region. Bundle projects allow for the reduction of capital costs (for instance through grouped purchase of equipment) and some of the operation costs can be shared between several projects located in the same region (for instance, the share of one monitoring consultant). Moreover, grouped projects can be submitted as only one project, thus reducing the costs related to the carbon offset project development.

Bundling can also be physical, which means different sources of on-farm material from different farms could be combined in one regional digester. That model is common in Germany for instance, and allow for the production of energy used in surrounding communities. Under this type of business model, several small farms can collaborate within a cooperative entity for instance, allowing them to access economies of scale otherwise not accessible. Under model of physical aggregation, distance between members and associated transportation costs are key. This model may be applicable only to high-density areas, where a critical mass of small farms are located within a small territory. It is recommended exploring where and under which conditions that model could be viable in Ontario, as it may positively impact the biogas production potential for the province.

At the light of the results presented in the report, we can conclude there still exist a significant potential for AD projects to be explored under the new market conditions. Those new factors have to be considered in a more detailed study, per region or county. Detailed study will allow the development of innovative region-specific and project-specific business models, which allow for aggregation of several small projects, as well as optimisation of alternative revenues such as carbon revenues.

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CANADIAN GAS ASSOCIATION
ASSOCIATION CANADIENNE DU GAZ

Renewable Natural Gas:
Affordable Renewable Fuel for Canada

ISSUE 2 2016

EXECUTIVE SUMMARY

As governments – both provincial and federal – discuss lower GHG emissions pathways, renewable natural gas (RNG or biomethane) presents a significant and largely untapped opportunity for GHG emission-free energy for our country. Using RNG means putting renewable energy directly in an existing pipeline: showing how pipes can deliver the benefits of renewables as efficiently (and often more cost-effectively) than electric wires.

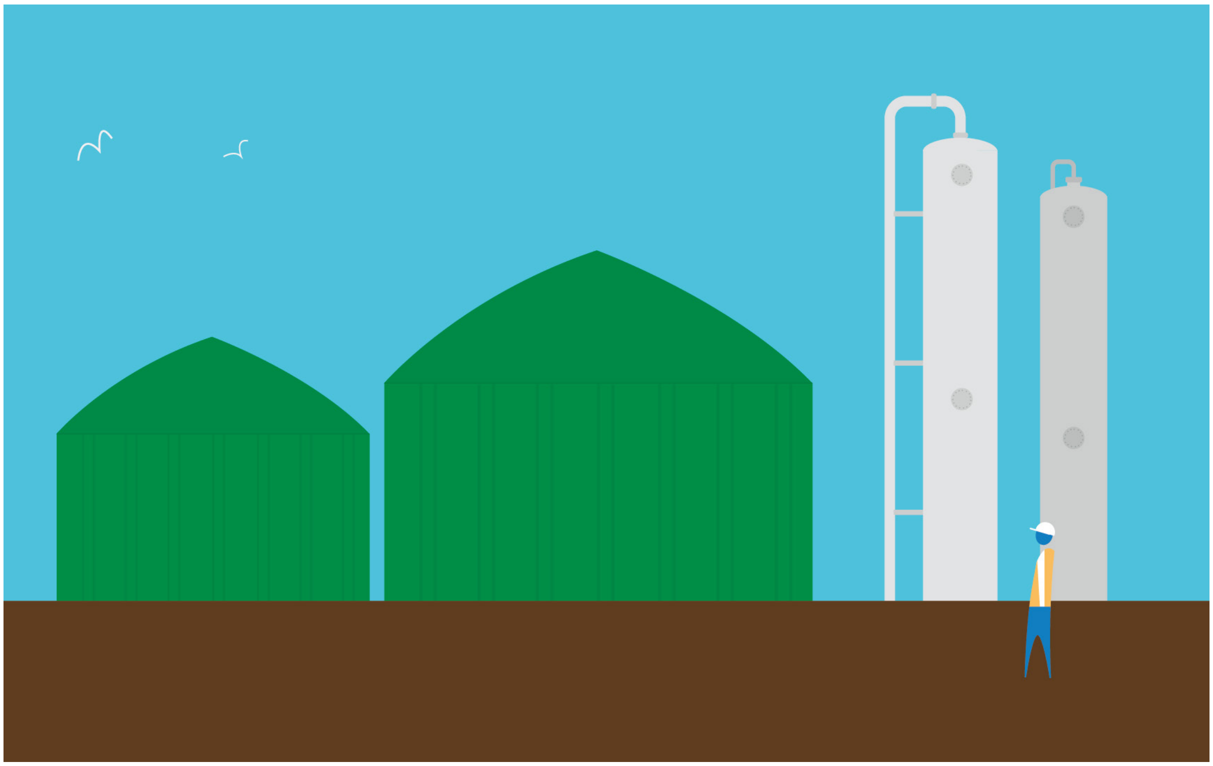
Canada has an RNG resource base of approximately 1,210 billion cubic feet (Bcf) per year, which is nearly 50 per cent of Canada's 2014 natural gas consumption. As a starting point, gas utilities are looking at measures to support a target of up to 10 per cent RNG into natural gas pipeline distribution systems by 2030. Nationally, this amount of RNG would be equal to approximately 267 billion cubic feet of natural gas per year. This volume of RNG could fuel 3.1 million homes with renewable fuel annually and would result in 14 megatonnes (MT) per year of GHG emission reductions per year, equivalent to removing 3 million passenger cars from the road.

Currently, in the provinces of British Columbia, Ontario and Quebec, natural gas distribution utilities are putting RNG into the pipeline distribution system. By the end of 2016, utilities will have brought online eleven RNG projects producing enough renewable fuel for 51,000 homes or equivalent to approximately 132 million litres of renewable fuel for transportation markets.

RNG, while more costly than geologic natural gas supplies, is a cost-effective source of renewable energy for Canada. RNG can be produced, cleaned and put into the natural gas distribution system at a cost of between \$10-25 per gigajoule (GJ), or equivalent to between 4-9 cents per kilowatt hour (kWh). For comparison, current renewable electricity contracts for utility scale solar in Ontario have been signed for approximately \$19 and \$44/GJ or 7-16 cents/kWh.

With the right policy measures in place, natural gas utilities can support lower GHG emission energy delivery to Canadians through the introduction of RNG into their distribution pipeline systems across the country. To this end, the Canadian Gas Association, in its 2016 pre-budget submission to the House of Commons Finance Committee, has requested \$50 million in federal support from the Canadian Green Infrastructure Fund to advance RNG projects in Canada. Further, CGA will be hosting a workshop on May 25th 2016 in Toronto with industry and government stakeholders to discuss the RNG potential for Canada and the various policy measures that could support a robust RNG market across the country.

OVERVIEW



This publication outlines the potential for RNG in Canada including its role in the reduction of GHG emissions, its value as an affordable renewable energy option for natural gas markets, and the role natural gas utilities can play in delivering this clean renewable product to Canadians.

RNG is a 100 per cent renewable energy source. RNG can be produced in two ways. The first is anaerobic digestion whereby waste (from landfills, farms or waste water treatment plants) is converted into methane and carbon dioxide in a digester or holding tank. The gas produced is then cleaned or purified to meet utility pipeline specifications. The digesters can be located at waste water treatment plants, landfills, at green bin waste facilities, or on farms. The second way to produce RNG is through gasification of forest or agricultural waste. Gasification uses high temperatures to thermally breakdown biomass into synthesis gas, a mixture of very simple gaseous compounds. This syngas is then reformed into methane to produce RNG.

After RNG has been captured, cleaned and injected in pipelines, it can be used in the same way as conventional natural gas by homes, businesses, institutions, and industry. RNG can also be used, like conventional natural gas, as a transportation fuel in the form of compressed natural gas (CNG) or liquefied natural gas (LNG).

An added benefit is that the end user requires no equipment upgrades or modifications, thus avoiding costly upgrades to the end use customer. Further, unlike solar or wind, RNG is produced year round without intermittency and it can be stored underground in natural gas storage facilities.

CANADA'S RNG OPPORTUNITY

In 2014, the total natural gas demand in Canada, was 2670 Bcf. As shown in Table 1, the ultimate potential for RNG in Canada is estimated to be 1210 Bcf per year[1]– equal to nearly half of Canada's 2014 natural gas consumption. The RNG potential is greatest in British Columbia (300 Bcf) followed by Quebec (282 Bcf). Of the total RNG potential in Canada, 85 per cent can be sourced from forest and agricultural waste while the remaining opportunity is from landfills, green bin waste, waste water treatment plants and farm-based digesters. It is important to note that in order for the RNG potential from biomass to be realized, there are technological improvements required to the biomass to RNG conversion process. Further, the biomass needed to generate RNG will have to be purchased in the open market and will compete with alternative uses of biomass resources including pellet plants and biomass use by industry for heating and/or power needs. Up until 2025, the majority of RNG potential exists in landfills, waste water treatment plants, and farm-based digesters. Post 2025, gasification of biomass and agricultural waste would begin to come on stream with appropriate technology in place.

Table 1: Provincial Gas Demand and RNG Potential for Canada

Province	Gas Demand (Bcf/year)	Residential Demand (Bcf/year)	Potential RNG Resource Base (Bcf/year)	Potential 2030 RNG Production (Bcf/year)	Percentage of Gas Demand	Number of Homes Gas Demand
BC*	210	70	300	10	5%	122,960
AB	1075	161	169	68	6%	792,464
SK	171	33	137	14	8%	160,603
MB	74	21	69	3	5%	40,444
ON	861	352	157	138	16%	1,615,272
QC	250	23	282	31	13%	366,640
NB	18	1	64	2	10%	22,508
NS	6	0.2	32	1	10%	7,503
Total	2665	662	1,210	267	10%	3,128,392

Sources: Statistics Canada, Table 128-0016. Alberta Innovates, 2010 and 2011, CGA notes. Note: *BC's Biomass is largely being contracted for and use in pellet plants. Therefore, at this time, much of BC's potential for RNG comes from landfills and digesters.

In addition to the production potential of RNG, there is a significant GHG emission reduction opportunity. Table 2 provides data and information on the 2014 GHG emissions from natural gas consumption in each province and the RNG emission reduction potential for each province by the year 2030, based on market conditions and available RNG supplies. Assuming 10 per cent of Canada's natural gas consumption is from RNG production, there exist significant GHG emission reductions opportunities for all provinces. Nationally, the GHG reduction potential is 14 megatonnes, equivalent to taking 3 million cars off the road. The greatest emission reduction opportunities are in provinces where the largest available RNG volumes exist. Along with this emission reduction opportunity there is a cost saving for RNG wherever CO2 emissions are priced – saving the consumer the carbon cost for the volume of RNG they use.

[1] RNG production potential is continually replaced as new waste is constantly produced from the various sources.

Table 2: Provincial Emissions and GHG Reduction Potential

Province	Natural Gas GHG Emissions (Megatonnes - 2014)	2030 Annual GHG Emissions Reductions from RNG (Megatonnes)	Number of Passenger Cars Equivalent
BC	11	0.6	116,197
AB	61	3.6	748,878
SK	7	0.7	151,770
MB	4	0.2	38,219
ON	41	7.3	1,526,432
QC	12	1.6	346,474
NB	0.2	0.1	21,270
NS	0.3	0.0	7,090
Total	136	14	2,956,331

Source: http://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator

RNG PROJECTS IN CANADA

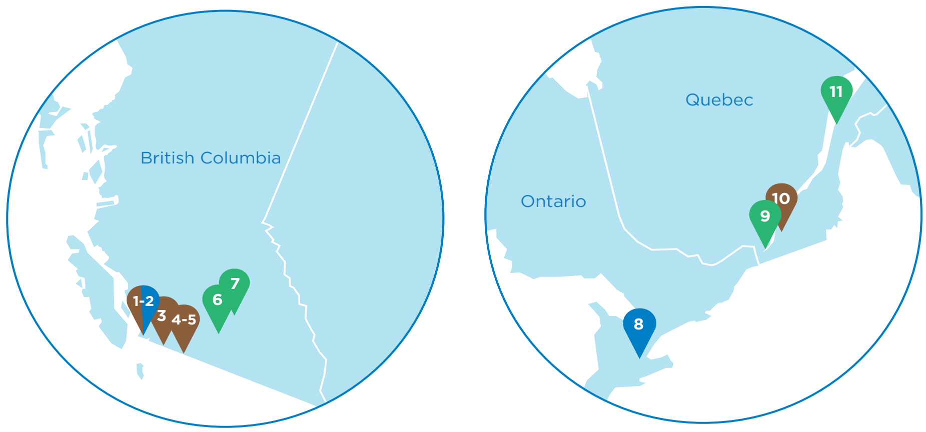
The map on page 5 illustrates operating and planned RNG production projects in Canada. The three provinces where RNG is currently being blended into the Canadian distribution system are British Columbia, Ontario and Quebec. By the end of 2016, the total quantity of RNG being produced in Canada will be equal to the annual natural gas demand of approximately 51,000 homes or 132 million liters of renewable transportation fuel.

In British Columbia, FortisBC offers a **voluntary RNG program** where RNG is purchased by ratepayers at a cost of ~$15/GJ. Participants can choose to blend between 5 per cent and 100 per cent RNG into their gas supply stream. There are at current, approximately 7,000 customers in British Columbia taking advantage of this program. In Ontario, there is a single RNG project **in Hamilton** from the municipal waste water treatment facility. The Region of Peel and the City of Toronto have expressed great interest in producing RNG from source separated organic waste that they collect. In Quebec, there are two landfills producing RNG and **an aerobic digester project** with the City of St Hyacinthe.

In addition municipalities across Canada are working with gas utilities to learn more about RNG and the role it can play in helping to reduce their GHG profile, optimize their waste diversion strategy, and help to meet their energy needs.

Canadian Renewable Natural Gas (RNG) Projects

Operating & In Development as of 2017



Digester

Landfill

Wastewater treatment gas

1 **Delta, BC**
Start date: 2014
RNG Production: 1,348 homes/year
Status: Operating

2 **Richmond, BC**
Start date: 2016
RNG Production: 505 homes/year
Status: In development

3 **Surrey, BC**
Start date: 2017
RNG Production: 1,100 homes/year
Status: In development

4 **Chiliwack, BC**
Start date: 2015
RNG Production: 1,348 homes/year
Status: Operating

5 **Abbotsford, BC**
Start date: 2010
RNG Production: 2,527 homes/year
Status: Operating

6 **Kelowna, BC**
Start date: 2014
RNG Production: 3,032 homes/year
Status: Operating

7 **Salmon Arm, BC**
Start date: 2013
RNG Production: 1,011 homes/year
Status: Operating

8 **Hamilton, ON**
Start date: 2011
RNG Production: 2,695 homes/year
Status: Operating

9 **Terrebonne, QC**
Start date: 2014
RNG Production: 28,000 homes/year
Status: Operating

10 **St. Hyacinthe, QC**
Start date: 2017
RNG Production: 5,054 homes/year
Status: In development

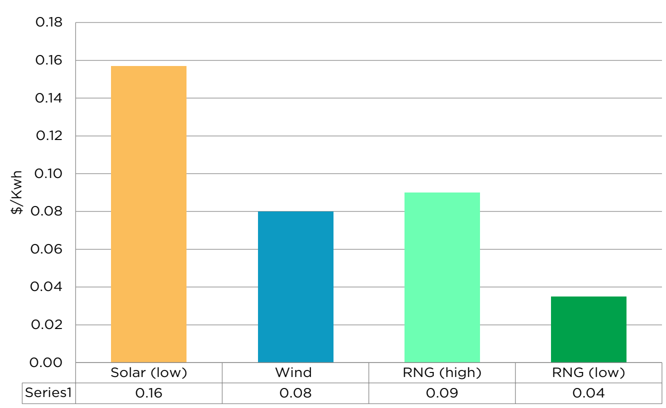
11 **Rivière du loup, QC**
Start date: 2016
RNG Production: 1,350 homes/year
Status: In development

RNG – AFFORDABLE AND VERSATILE

On affordability, Figure 1 provides information on renewable energy costs for wind, solar and RNG (both a high and low cost).

As illustrated, RNG is extremely competitive with modern renewable electricity generation sources and in all cases is more affordable than Canadian utility scale solar power. As was witnessed with wind and solar, the cost of RNG will decline significantly as it gains a larger share of the market and economies of scale are built into manufacturing of RNG clean up technologies and processes. These costs are important considerations as jurisdictions across Canada look to lower the GHG emission footprint of their energy system while at the same time keeping energy affordable.

Figure 1: Comparing Canadian Renewable Energy Costs



Source: http://fit.powerauthority.on.ca/fit-program/fit-program-pricing/fit-price-schedule, CGA member companies and RNG project data.

RNG costs vary between $10-25/GJ depending on the source, with landfill gas being the most affordable production method and RNG from forest and agricultural waste at the higher end of the RNG cost spectrum. In terms of electricity equivalent pricing, RNG costs between 4 – 9 cents/kWh. For comparison, current renewable electricity contracts for utility scale solar in Ontario have been signed for approximately $19 and $44/GJ or 7-16 cents/kWh.

On versatility, RNG is the same methane molecule as any other natural gas. It can therefore be used in any energy application that uses natural gas. From furnaces and water heaters to transportation fuel or power generation, RNG can meet the energy needs of consumers. The use of existing pipeline infrastructure to deliver RNG to consumers is a significant benefit to Canada as it enables a high utilization of extensive distribution pipeline assets – lowering energy costs to customers and operating costs to utilities – all while significantly reducing emissions, fostering innovation and creating new economic activity.

POLICY DRIVERS FOR RNG IN CANADA

In the United States 35 out of 50 state legislatures provide support for RNG as part of their renewable portfolio standards for electricity production. Federally, the U.S. Environmental Protection Agency provides an RNG incentive through its Renewable Fuel Standard. In 2015 alone, 500 million litres of renewable fuel were produced from RNG for use in U.S. transportation markets[2]. Additionally in California, there is a further incentive being offered to RNG producers. As a result of these policies, some RNG project operators in Quebec are selling their RNG volumes into the California market where they can receive a renewable energy incentive.

In Canada, various policy measures could help realize the true potential of RNG for the country's energy future. Investment tax credits for RNG projects, direct program support to offset higher RNG costs and the introduction of gas utility renewable portfolio standard (RPS) programs for RNG are three possible measures. At this time, various policy scenarios are being explored across Canada. More consultation between governments, industry and communities is required to determine the best approach to provincial and federal policies that can support a RNG industry.

In a 2016 pre-budget submission to the House of Commons Finance Committee, CGA requested $50 million in federal support from the Canadian Green Infrastructure Fund to advance RNG projects in Canada by providing grants to projects to support efforts to reduce cost and risk. CGA is also seeking pilot demonstration funding to further advance biomass gasification technology. As a first step in the dialogue on RNG, CGA is convening a RNG Workshop on May 25th in Toronto that will include industry and government stakeholders. The workshop will explore the RNG potential for Canada and the opportunities for various policy measures that could support RNG supplies across the country.

[2] http://www.epa.gov/fuels-registration-reporting-and-compliance-help/2015-renewable-fuel-standard-data

CONCLUSION

Our commitment, as Canada's natural gas industry, is to work to constantly ensure the provision of safe and reliable energy services to Canadians with clean and affordable natural gas. RNG is one more product offering we can make to ensure this, and we want to work with stakeholders to make it available across the country.

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CLOSING THE LOOP

Primer for Municipalities, Food Processors and Fleets on Fueling Vehicles Using Renewable Natural Gas

Canadian Biogas Association

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The views expressed in this report are the views of the Canadian Biogas Association and do not necessarily reflect those of the governments of Canada and Ontario.

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The Biogas Association wishes to thank the expert advisory committee that assisted in the development and review of this Closing the Loop Primer. The committee consists of staff from:

- Bio-en Power
- Change Energy
- Ontario Ministry of Agriculture, Food and Rural Affairs (OMAFRA)
- Union Gas
- Integrated Gas Recovery Services (IGRS)

CLOSING THE LOOP

Primer for Municipalities, Food Processors and Fleets on Fueling Vehicles Using Renewable Natural Gas

Canadian Biogas Association

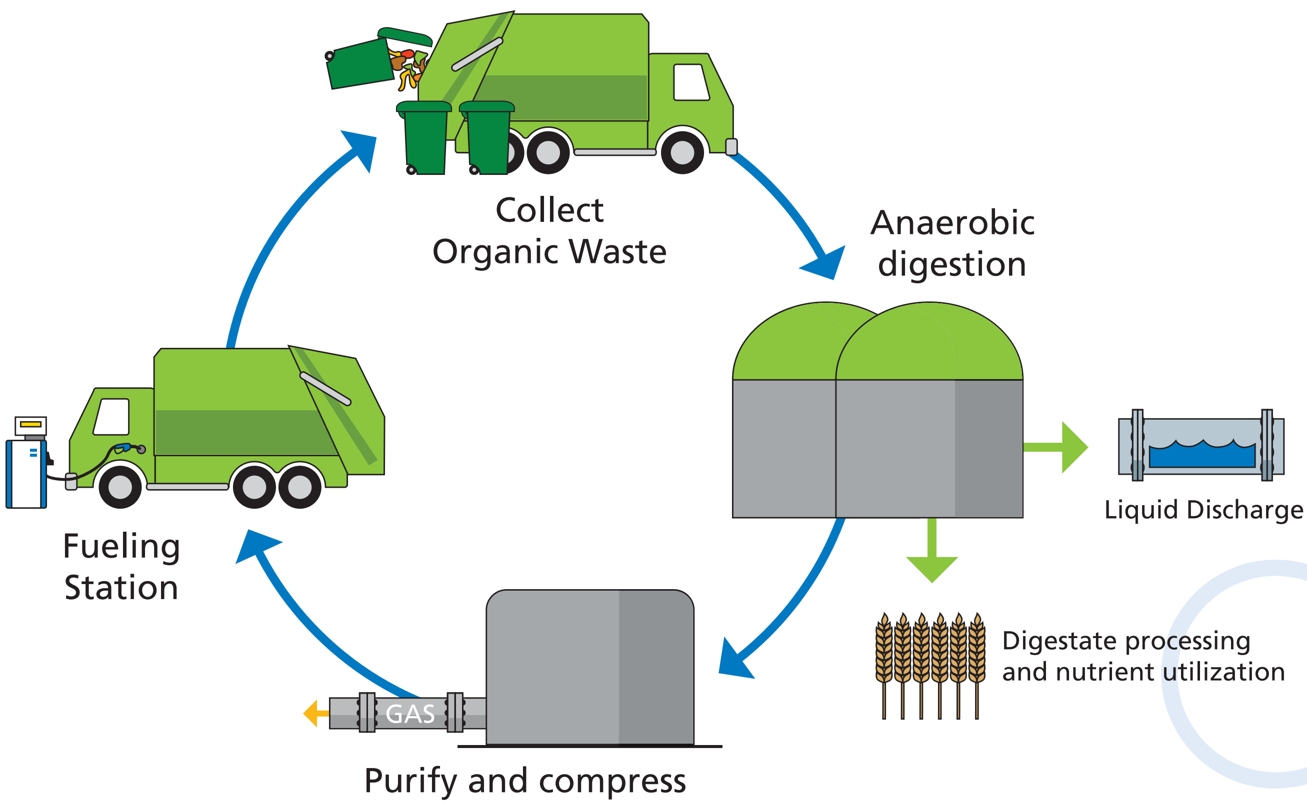
Contents

Introduction

Renewable natural gas (RNG) from food waste and organic material is the next game-changer in vehicle fueling. RNG is cost-competitive with diesel fuel, and is carbon neutral.

RNG vehicle fueling is your organization's biggest opportunity for near-term, cost-neutral sustainability.

Not only can food waste be considered a resource, but it can be converted cost-effectively into a renewable vehicle fuel, significantly elevating its value.



CLOSING THE LOOP

Primer for Municipalities, Food Processors and Fleets
on Fueling Vehicles Using Renewable Natural Gas

YOU CAN CLOSE THE LOOP IN THREE WAYS:

1. Stop sending your organic materials to landfill, and instead harvest vehicle fuel
2. Fuel your fleet from local organic material
3. Use locally-produced RNG and keep your energy dollars in your community instead of purchasing fossil-fuel based diesel and gasoline produced outside your community.

By *Closing the Loop*, your organization can take a meaningful step toward reducing carbon emissions, make money, help your fleets and/or other fleets in your community be more green, and be effective leaders in energy sustainability.

This primer shows you how your organization can close the loop. It helps identify if compressed natural gas (CNG) and RNG are right for you, outlines how RNG fits with municipal planning and policy development, and highlights case studies and lessons learned. It is part of a larger *Closing the Loop* initiative, which includes workshops, tours, and networking to promote the adoption of RNG as a vehicle fuel.

Closing the Loop is a collaborative initiative of the Canadian Biogas Association, and involves working with municipalities, food processors, energy and waste management companies to divert organic materials from landfill, and use them to generate biogas and renewable natural gas (RNG). It is supported by Growing Forward 2, a federal-provincial-territorial initiative, Bio-En Power, Bullfrog Power, and Union Gas.

The chart below shows why CNG is being adopted by fleets – up to 40% lower operating costs than diesel or gasoline, based on five-year price averages:

Fuel	Price	GHG Impact
Gasoline and diesel	~$1.15/litre	Base case
Compressed natural gas	~$0.60/litre	25% lower than base case
Compressed RNG	~$1.15/litre	90% lower than base case
CNG/RNG blend (90%/10%)	~$0.65/litre	31% lower than base case

Note that the CNG and RNG numbers are expressed in diesel litre equivalents (DLE). One cubic metre of natural gas or RNG has the energy equivalent of one litre of diesel fuel.[1] This makes a CNG/RNG blend cost effective at about 60-65% of the price of diesel.

The chart also shows that switching to CNG results in emissions reductions of about 25% from diesel or gasoline. Fueling with RNG results in emissions reductions of about 90% from diesel or gasoline. A blend of CNG with 10% RNG results in emissions reductions of about 31%, and provides added benefits which are outlined in this document.

1 *Go With Natural Gas*

Early Adopters: Municipal Fleets

The Canadian Biogas Association's *Closing the Loop* initiative builds on the visionary work of leading municipalities that have a sustainability focus and are moving to reduce greenhouse gas emissions and transportation costs, while recycling organic material. Many municipalities are transitioning to CNG vehicles to save money and reduce GHG emissions. With secure organic material supply, return-to-base fleets, and strong public-interest priorities, municipalities are logical early adopters.

RNG is a logical fuel to integrate into CNG fleets, as it can be injected at its production source and vehicles can be fueled anywhere on the natural gas pipeline. In other words, the vehicles do not have to be fueled where the RNG is produced. Municipalities can generate RNG at their wastewater or SSO treatment facilities, or their landfills, or in purpose-built food waste biogas systems. In Canada alone, the following municipalities are planning or have implemented RNG as a vehicle fuel from the sources shown below:

City	Source	Status (in 2015)
Nanaimo	Landfill	Under construction
Surrey	SSO	Under construction
Hamilton	Wastewater treatment	Complete
Niagara	Wastewater treatment	Under study
London	SSO	Under study
Saint-Hyacinthe	Wastewater, SSO and industrial waste	Under construction
Rivière-du-Loup	SSO and landfill	Under construction

Many of these municipalities are showcased in more detail in this primer.

Food Processors and Waste Management Companies

Food processors and their waste management companies can close the loop by diverting their organic waste outputs to anaerobic digestion (AD) facilities, located either off-site or as part of on-site wastewater treatment, instead of sending them to landfill. They can also consider purchasing RNG as a vehicle fuel, or work with their waste haulers to make the switch, which closes the loop by using the outputs of food processing as an input or fuel to the waste vehicles.

First, sending material to biogas facilities is cost competitive with landfill for Ontario companies, and has a number of benefits, including:

- Significantly lower greenhouse gas emissions. Digesting half of the 6 million tonnes of food waste discarded in Canada each year would save 2.2 million tonnes/year of eCO_2. This is equivalent to taking 490,000 cars off the road.[2]
- Nutrients are returned to the soil. Recycling nutrients from municipal, industrial and commercial operations is an important ongoing source of soil health.
- Protecting water sources through pathogen destruction of organic material and mitigating risk of potential environmental impact.
- Contributes to renewable energy production, green job creation and local energy security.

2 Canadian Biogas Association, *Canadian Biogas Study Summary*, November 2013.

Second, food processors that have sustainability goals can consider using a blend of conventional compressed natural gas (CNG) and RNG for their trucking needs. Many fleets are making the switch to CNG from diesel because of the lower cost and lower greenhouse gas emissions as outlined in the chart above.

Exciting Industry Trends:

- At the City of Surrey, BC, organic material will be processed at a facility and converted to RNG to fuel 100% of the energy needed for the waste fleet. The business case was built comparing RNG to diesel prices and the facility will be a public-private partnership.
- In southwest Ontario, the *Rural Green Energy Project* is in development and will generate RNG, blend it with CNG, and sell it as a vehicle fuel to a fleet of milk trucks, local farms, and other businesses and customers.
- Progressive Waste Solutions has the largest fleet of CNG waste vehicles in Canada, and has opened a RNG injection facility at its Terrebone landfill site in Quebec, selling RNG to the US.
- Waste Management is using RNG from its landfill in Fairmont City, Illinois to fuel its waste trucks. “This innovative facility utilizes renewable landfill gas, and purifies it to a high-quality natural gas that in turn feeds into the adjacent pipeline to fuel our growing fleet of CNG trucks,” says Jim Trevathan, executive vice president and chief operating officer for Waste Management.
- Entrepreneurs at Atlas Disposal teamed up with Clean Energy Fuels, and currently provide RNG to Atlas’s own waste fleet, and to the City of Sacramento’s waste fleet.
- “Redeem” is a branded RNG fuel by Clean Energy Fuels that is available across the U.S. to natural gas vehicle fleets including heavy-duty trucks, refuse trucks, airport shuttles, taxis, and buses.

Moving from Yesterday's Fleet to Tomorrow's Fleet

The transportation sector has been identified as a major contributor to greenhouse gas (GHG) and air pollutant emissions. In Ontario, over 34% of our greenhouse gas emissions come from transportation.[3] One in five trucks and buses in Canada is over 20 years old. Choosing natural gas vehicles (NGVs) to replace older fleet vehicles or to upgrade existing ones by modifying them to become NGV would result in long-term economic benefits and significant reductions for both air pollution and GHG emissions.[4]

Examine your fleet and your ability to benefit environmentally and economically by choosing to replace aging fleet vehicles, or upgrade existing fleet vehicles, with NGVs. Consider your fleet: what portion of vehicles do you renew every year? For vehicles less than five years old there are clear benefits to converting from diesel over to dual-fuel diesel/CNG. For older vehicles, consider a phased plan to purchase new CNG vehicles. It's only by converting to CNG vehicles that you can capitalize on the RNG opportunity.

Why Choose CNG over Diesel?

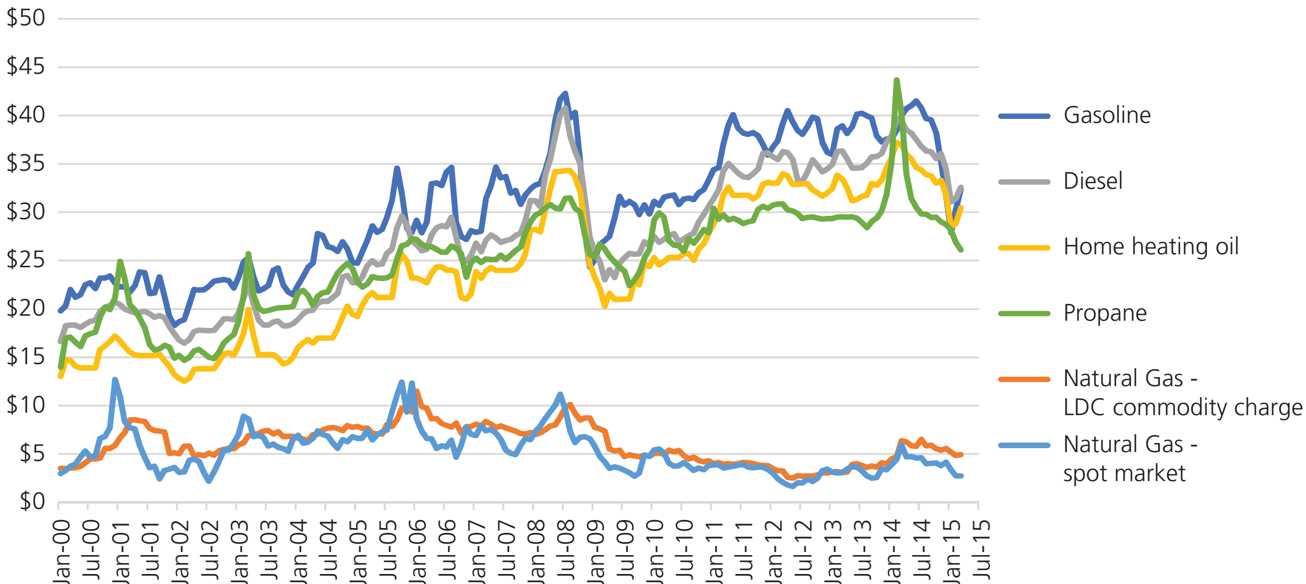
Compressed natural gas (CNG) is a competitively priced fuel that has historically sold at a significant discount to crude oil-based fuels. The recent advances in extraction techniques have resulted in an increase in the North American natural gas supply, which analysts predict will maintain the commodity price advantage for CNG vehicle fuel for the foreseeable future.[5]

Natural gas is no longer tied to oil price volatility. The pricing of natural gas became de-linked from world oil prices in late 2008. While approximately 60% of pump price for diesel is linked to fluctuating crude oil commodity prices, only about 30% of pump price for natural gas is tied to the historically more stable natural gas commodity price.[6]

3 *Ontario Climate Change Discussion Paper*, 2015, p. 30
4 *Canadian Natural Gas Vehicle Alliance. (2015). Environment & Safety*
5 *Natural Gas Use in Transportation Roundtable. (2010). Natural Gas Use in the Canadian Transportation Sector-Deployment Roadmap*
6 *Union Gas Ltd. (2014). Natural Gas for Fleet Vehicles: The Answer to Rising Energy Prices and Lower Emissions Targets*

On average, CNG fuel prices are 40% less than other vehicle fuels.[7] The chart below shows energy commodity prices in Canada over a 15-year period. Note that retail sale prices for CNG are different than natural gas, but retail data is not published.

ENERGY COMMODITY PRICES – CANADA
($/mmBtu)



Source: StatsCan 326-0009, Kent Group, CGA

When considering a switch to CNG vehicles, analysts[8] use models that assess a number of factors, including:

- If natural gas (CNG or LNG) is an appropriate fuel for the fleet
  - o Lifecycle cost over 10 year timeframe
  - o Refueling patterns and distance driven (e.g., return-to-base each night)
  - o Power requirements of the vehicles
- Value propositions
  - o Financial analysis including cost forecast
  - o GHG reductions and their importance to the operator
- The correct fueling station configuration/network for the operation
- Location, including site conditions
- Natural gas distribution infrastructure and cost to connect
- Proximity to other natural gas refueling stations
- Local transportation fuel demand characterization
- Supportive policies and programs
- Sensitivity analysis of risks

7 Union Gas Ltd. (2014). *Natural Gas for Fleet Vehicles: The Answer to Rising Energy Prices and Lower Emissions Targets*
8 Analysis in this section provided by Change Energy

Analysts examined a wide range of fleet cases to determine the relative sensitivity of the business case to a variety of factors. Here are some real-world examples:

- Fleet size and implementation rate: In one example, a fleet of 25 waste haulers, a quick adoption of all vehicles gave a payback of three years, whereas a staged adoption (five vehicles/year) gave a payback of five years, even with a phased-in installation of the refueling station.
- The amount of fuel used: In comparing two identical fleets of 25 waste haulers, a fleet with an annual mileage/vehicle/year of 40,000 km had a three-year payback, whereas the same fleet with an annual mileage of 20,000 km/vehicle/year had a six-year payback.

Other sensitivity analyses have been conducted looking at such factors as:

- Construction schedule
- Financing costs
- Fuel price differential
- Utility costs
- Maintenance costs

Currently, CNG is not subject to a fuel tax in Ontario. Historically, governments have favoured innovative fuels during adoption periods to incent new adoption. For instance, biodiesel first gained commercial momentum in the early 2000's, and was exempt from Ontario's Fuel Tax. Ontario's 14.3 c/L Fuel Tax was applied to biodiesel in 2014 only after a B2 mandate (a requirement for 2% of diesel sold be biodiesel) was implemented.[9]

Although NGVs cost typically 20-40% less to operate than gasoline-fueled vehicles, each fleet should conduct its own analysis based on its usage patterns.

Does RNG Blending Make Sense Economically?

While RNG is more expensive than CNG, it is about the same price as diesel or gasoline. It is also the greenest, cleanest way to go. By blending a portion of RNG fuel with your CNG you can be green and still save money. RNG can be integrated into CNG in a 10/90 blend in order to achieve the emissions reductions benefits associated with RNG. Since RNG is more expensive to produce than conventional natural gas, a 10% blend adds ~5 cents/litre to the price of CNG, which maintains the strong economic advantage of using CNG/RNG over crude oil-based fuels.

Clean Energy Fuels, a U.S. and Canadian fuel retailer, has successfully integrated RNG into its product offering. RNG under the Redeem brand made up 17% of total CNG sales for Clean Energy Fuels in the U.S. and Canada. Redeem-branded RNG sales in 2014 were over 74 million diesel litre equivalent.

9 Government of Ontario, http://www.fin.gov.on.ca/publication/fuel-biodiesel-exemption-revocation-en.pdf

According to Union Gas analysis, the following price scenarios for different RNG blends, based on different costs of RNG production, can be calculated.

Scenarios	100% CNG*	10% RNG @$6/GJ	100% RNG @$6/GJ	10% RNG @$15/GJ	10% RNG @$32/GJ
Cost component:	($/DLE)	($/DLE)	($/DLE)	($/DLE)	($/DLE)
Gas ($4/GJ) + delivery	0.18	0.20	0.26	0.23	0.30
O&M + Cap recover	0.36	0.36	0.36	0.36	0.36
Taxes	0.07	0.07	0.08	0.08	0.09
Total	0.62	0.63	0.70	0.67	0.74
Difference		$0.01/L	$0.07/L	$0.05/L	$0.12/L

** Note that this represents in-house CNG refueling (not retail) costs. O&M and capital recovery estimates represent a fleet of moderate size and utilization. Small fleets, with low utilization may results in higher CNG fueling costs, while large fleets with high utilization may achieve lower CNG fueling costs than the example provided.*

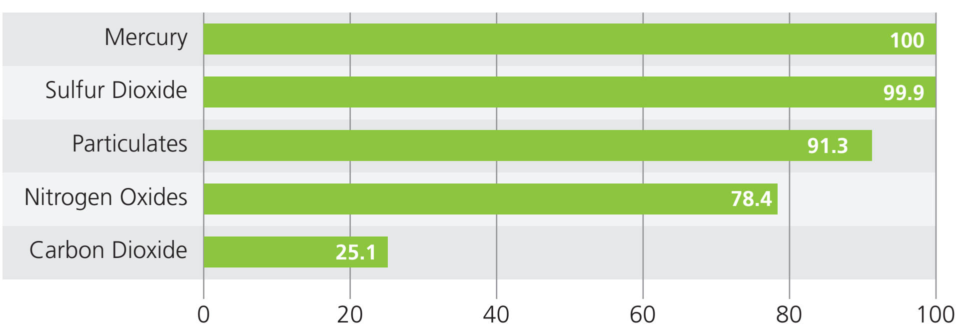
Environmental Benefits of Blending RNG

The transportation sector is the largest contributor of GHG in Canada (24%)[10] and about 34% of Ontario's greenhouse gas emissions come from transportation[11]. Natural gas can provide an advantage for companies striving for GHG emission reductions, as conventional natural gas vehicles emit up to 25% less carbon on a fuel lifecycle assessment (also described as well-to-wheel) basis compared with diesel or gasoline.[12] Lifecycle assessments take into account the carbon emissions from each step of a fuel's lifecycle – from production and distribution to combustion at the tailpipe. A fuel lifecycle assessment typically quantifies emissions across two stages: well-to-tank and tank-to-wheels.[13]

Using natural gas as a vehicle fuel generates fewer atmospheric pollutants than diesel as well. See the chart below:

NATURAL GAS VEHICLES CAN REDUCE CO_2 EMISSIONS BY 25%

Natural gas emission reductions versus gasoline (EIA 2010)



Displacing one Gasoline Gallon Equivalent (GGE) of vehicle fuel with natural gas

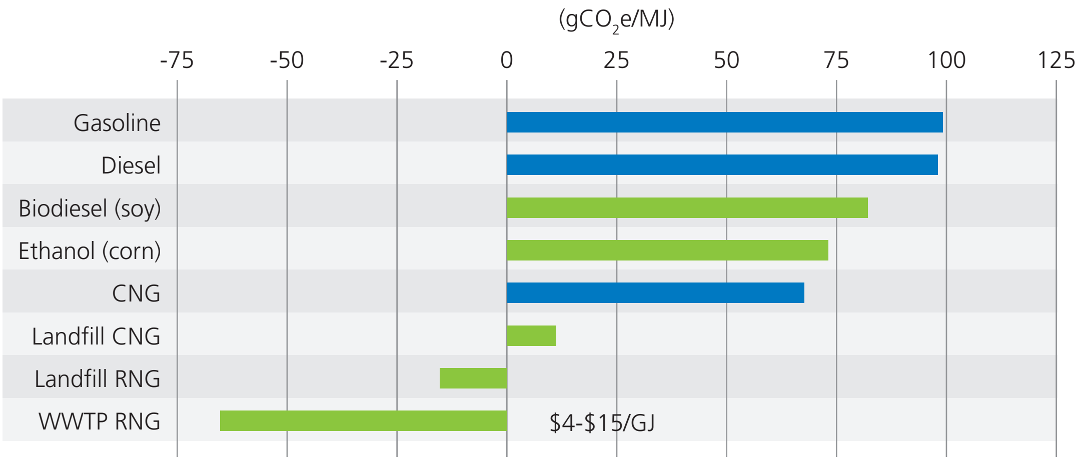
Source: https://www.iea.org/publications/freepublications/publication/natural_gas_vehicles.pdf

10 Environment Canada, Canada Emission Trends, 2013
11 Ontario Climate Change Discussion Paper, 2015, p. 30
12 Natural Gas Use in Transportation Roundtable. (2010). Natural Gas Use in the Canadian Transportation Sector-Deployment Roadmap
13 Electric Ride Colorado

Overall, blending 10% RNG with 90% CNG offers GHG emissions reductions over 31% in comparison with diesel.

When RNG is used to fuel natural gas fleet vehicles, lifecycle greenhouse gas emissions can be reduced by about 90%. This is an industry-accepted estimate, and reflects an average of sources of RNG, including agricultural operations. For municipalities, however, the following California data relates to municipal sources of RNG:

CARBON INTENSITY OF VARIOUS FUELS



Data Source: Carbon Intensity Lookup Table for Diesel and Fuels that Substitute for Diesel, California Air Resources Board, 2012

Why Does RNG Have Such a Big Greenhouse Gas (GHG) Benefit?

RNG is a renewable fuel that provides significant GHG reduction benefits. The displacement of a carbon-positive fuel, such as natural gas, through the use of this fuel results in a net reduction of GHG emissions.[14] Capturing biogas from organic wastes reduces GHG emissions by preventing methane from directly entering the atmosphere. The carbon dioxide that is generated during the production and combustion of RNG is used in the regeneration of new biomass, representing a closed-loop cycle for carbon dioxide that is released. For these reasons, RNG is considered to be a carbon neutral fuel and energy source since no net GHGs are released into the atmosphere through either the combustion or lifecycle emissions of RNG.[15]

Carbon Pricing

Provincial carbon pricing schemes assist in RNG development. Carbon policies translate to financial support as demonstrated in BC and Quebec of about $1.50/GJ and 50 cents/GJ, respectively. The carbon pricing benefit expressed in DLE is 5 cents/DLE in BC, and 1.5 cents in Quebec. Ontario's cap and trade system designers are encouraged to include carbon pricing for RNG.

With total costs to produce and compress RNG of about $1.00/ diesel litre equivalent (DLE), comprised of $0.65/DLE (or $18/GJ) to produce, plus $0.40/DLE to compress, carbon pricing has a minor influence on the business case. Additional government support will be required to build the market. U.S. policy, for example, has been successful.

14 Natural Gas Use in Transportation Roundtable. (2010). Natural Gas Use in the Canadian Transportation Sector-Deployment Roadmap
15 Quest. (2012). Renewable Natural Gas: The Ontario Opportunity

CNG Vehicle Technology

There are an estimated 11 million NGV in use in over 30 countries globally. Canada has used natural gas as a transportation fuel for more than 25 years. The Canadian natural gas vehicle industry has engaged with the Canadian government to establish codes, standards and regulations in order to ensure that CNG vehicles are safe and that CNG refueling stations have been installed according to industry standards. Canada played a formative role in the development of internationally recognized standards for CNG fuel storage tanks that are used in Canada and abroad. There is a strong safety record for NGV and the industry works closely with local authorities to ensure that CNG continues to be a safe and reliable transportation fuel.[16]

New NGVs for fleets typically cost between $15,000 and $35,000 more than conventional diesel fleet vehicles. The higher initial investment for CNG fleet vehicles is offset by the substantial fuel savings from using CNG over diesel.[17] A waste truck that uses 35,000 litres of diesel per year would achieve economic payback for the price differential within three years.[18] With the recent increase in interest for CNG-fuelled fleet vehicles, the relative cost of purchasing these vehicles has begun to decline due to economies of scale.

In Canada, Cummins Westport supplies two natural gas engines, ISL G 8.9L and ISX12 G 11.9L, which are suitable for municipal return-to-base fleet operations. These engines are comparable to diesel engines in both performance and warranty coverage.[19] Both engines meet 2014 U.S. Environmental Protection Agency (EPA) and California Air Resource Board (ARB) emission standards as well as the 2014 EPA and U.S. Department of Transportation fuel economy and greenhouse gases regulations.[20] To date, Environment Canada has matched all regulations which the EPA has created, and therefore both engines are compliant with Environment Canada's requirements.

A variety of factory-built CNG light duty trucks and cars are available for fleet users as well. Generally fuel costs make up a smaller proportion of total ownership cost on smaller vehicles, meaning the business case is not as clear as for larger vehicles. However there are still clear greenhouse gas and air quality benefits to be had from any CNG vehicle.

Dual-fuel vehicle conversions can also make sense, particularly to alleviate "range anxiety" and to provide a power boost for certain applications. In a dual-fuel conversion, the vehicle maintains its capacity to run on diesel fuel, while often achieving fuel switching rates of 50-65%. In Ontario, a fleet of milk trucks is currently converting existing vehicles and find high fuel switching rates, while maintaining the significant power demands required to haul large volume milk trailers.

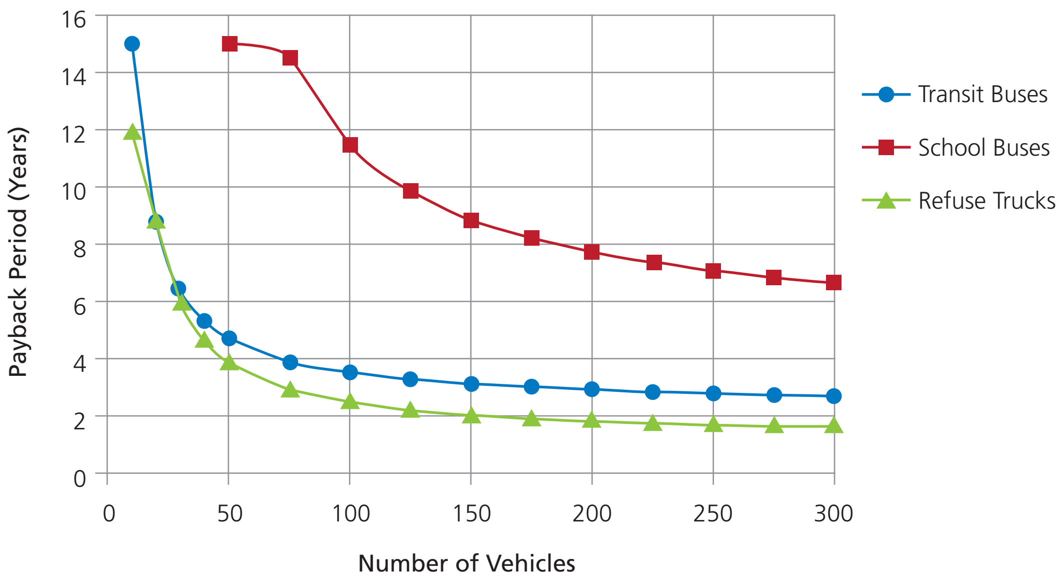
16 CNGVA. (2015). *Renewable Natural Gas*
17 Crittenden, G. (2014). *Natural Gas Vehicles for the Waste and Recycling Industry*
18 Milner, A. (2013). *Compressed Natural Gas*
19 Milner, A. (2014). *Factory-Built Natural Gas Trucks*
20 Cummins Westport. (2015). *Heavy-Duty Natural Gas Engines*

The following data tables may assist fleet managers in understanding the economics behind fleet conversion.

Truck Procurement and Fuel Cost				
Change only cells highlighted in Yellow, i.e., # of trucks added annually, $/liter, and # litres consumed annually				
Truck Procurement	**# of Trucks**	**Cost Per Diesel Truck**	**Cost Per CNG Truck**	**CNG Savings vs Diesel**
Cost Per Truck		$250,000	$285,000	$(35,000)
Initial Truck Purchase	15	$3,750,000	$4,275,000	$(525,000)
Next Truck Purchase	15	$3,750,000	$4,275,000	$(525,000)
Next Truck Purchase	15	$3,750,000	$4,275,000	$(525,000)
Next Truck Purchase	15	$3,750,000	$4,275,000	$(525,000)
Total Trucks	60	$15,000,000	$17,100,000	$(2,100,000)
Fuel Costs (Flat Line)		**Diesel**	**CNG**	
Estimated Fuel Cost Per Litre		$1.20	$0.60	$ –
Estimated Litres Consumed Per Truck Per Year		35,000	38,500	
Annual Fuel Cost Per Truck		$42,000	$23,100	$18,900
Year 1	15	$630,000	$346,500	$283,500
Year 2	30	$1,260,000	$693,000	$567,000
Year 3	45	$1,890,000	$1,039,500	$850,500
Year 4	60	$2,520,000	$1,386,000	$I,134,000
Year 5	60	$2,520,000	$1,386,000	$I,134,000
Year 6	60	$2,520,000	$1,386,000	$I,134,000
Year 7	60	$2,520,000	$1,386,000	$I,134,000
Year 8	60	$2,520,000	$1,386,000	$I,134,000
Year 9	60	$2,520,000	$1,386,000	$I,134,000
Year 10	60	$2,520,000	$1,386,000	$I,134,000
10 Year Total Fuel		$21,420,000	$11,781,000	$9,639,000
Total Truck Cost		$15,000,000	$17,100,000	$(2,100,000)
10 Year Truck Purchase & Fuel		**$36,420,000**	**$28,881,000**	**$7,539,000**
Average Savings Per Truck				**$125,650.00**

Source: Clean Energy Fuels, Natural gas vehicles supplement in Solid Waste and Recycling Magazine, 2014, P.26

PAYBACK PERIOD BY FLEET SIZE



Source: National Renewable Energy Laboratory, Fueling Change, p.3

Fleet Refueling

The cost for a typical CNG refueling station ranges from approximately $600,000 for 15 trucks to $1.3 million for 50 trucks, and up to $1.8 million for 100 trucks, depending on site-specific requirements and conditions. The costs associated with modifications to vehicle maintenance facilities and the purchase of equipment for vehicle maintenance must also be factored into budgets. The costs for these vehicle maintenance facilities range from approximately $70,000 for a two-bay shop to upwards of $175,000 for larger operations.[21]

There are three options for refueling: Fast fill, slow or time fill, and combination systems.

SLOW OR TIME FILL

Return-to-base fleet vehicles most commonly use "slow fill" CNG refueling stations. At these refueling stations, all vehicles are plugged in at filling posts and refuelled simultaneously overnight. The complete refueling process takes approximately eight hours. There are several advantages of slow fill. The primary advantage is lower capital expenditure by using a smaller compressor and little or no storage. There can also be benefits from off-peak electricity for compression if time-of-use rates are available. In addition, the heat of compression dissipates over time, making it easier to achieve a true full fill.

21 Crittenden, G. (2014). Natural Gas Vehicles for the Waste and Recycling Industry

FAST FILL

Fast fill refueling is best suited for relatively small volumes (less than 50 litres at a time), and in cases where fueling is intermittent and a fast turn-around time is desired (e.g., six minutes or less). A retail facility that services vehicles that arrive through the day might consider fast-fill capacity.

Fast fill station design: www.angienergy.com

COMBINATION FILL

Combination fast and slow fill systems are typically employed by facilities that can take advantage of the benefits that slow fill fueling provides, but that also provide fueling services to external fleets, or to vehicles of their own that may routinely require quick fueling.

Partnering with other organizations that operate fleets to share fueling infrastructure can be highly beneficial for fast fill facilities, as it allows the infrastructure to be used regularly.

Local Economic Benefits

Part of the goods and services procurement decisions for some organizations, particularly municipalities, relate to the impact on the local economy. Some local economic advantages of using a CNG/RNG blend for vehicles include:

- Revenue generated from the production and use of RNG is kept local. This revenue is sometimes referred to as "sticky dollars"
- Waste is treated locally, keeping jobs and associated revenue in the local economy
- Diverting organic wastes generates revenue while extending the life span of local landfills
- Local economies benefit from the energy resilience associated with producing energy locally rather than relying on imported energy, and being subject to price volatility
- Revenue opportunities for sharing CNG fueling infrastructure with other users

Steps to Success – RNG Production

The production of RNG offers an attractive waste management solution for closing the loop between organic waste and fuel. Converting organic materials to RNG captures energy from waste, diverts waste from landfill, reduces odour, and can fuel return-to-base fleet vehicles. RNG can be injected at its production source and piped to any vehicle fueling location.

This section addresses RNG sources, the business case for RNG generation, a brief technology overview, connection requirements, regulations and approvals, and where to go for more information.

Suggested steps to follow when considering producing RNG include:

1. Examine objectives in relation to RNG production, including sustainability objectives and GHG reduction, local economic benefits, and cost recovery from organic waste processing.
2. Contact companies and municipalities that have experience in planning or implementing RNG projects, and ask for lessons learned. Refer to the case studies in this primer.
3. Consult with experts, including technology suppliers, your natural gas supplier, and engineering and technology firms to help understand the business case, resources and level of effort required, and timeframes to expect.
4. Socialize the concept internally, including with your internal and contracted fleet operators. Winning support for these undertakings requires educating, consulting and collaborating with colleagues.

Municipalities can generate RNG from their landfills, residential source separated organic material, and wastewater treatment. These sources of RNG are briefly described below. (See the Canadian Biogas Association's *Municipal Guide to Biogas* if you are interested in generating electricity, not RNG, from these sources.)

LANDFILLS

Landfills are relatively large producers of biogas concentrated at a relatively small number of sites across Canada. While some sites generate electricity and sell it to the grid, several landfills are not able to connect. Many of these sites offer sufficient economies of scale to produce RNG fuel for fleet vehicles used for waste management and other services, creating local closed-loop energy systems.

Landfills that are located close to natural gas pipelines can inject into the pipeline.

See the Nanaimo case study below.

Convince Your Colleagues to *Close the Loop*

- **Refer to what has been done.** List the Canadian projects (page 3) and case studies (page 19).
- **Visuals help.** Use graphics and charts from this primer to illustrate the opportunity.
- **Be bold.** Cultures are shifting toward climate action. Use the momentum!

SOURCE SEPARATED ORGANICS (SSO)

Residential SSOs represent a substantial and relatively undeveloped new source of material for renewable fuel production. Many municipalities have implemented green bin programs to collect household organic wastes, and this SSO represents another opportunity for creating local closed-loop energy systems by fueling fleet vehicles used for SSOs collection, particularly if SSO-fueled biogas systems are built on natural gas pipelines that have capacity to accept fuel.

Note that trucks can be fueled anywhere, since RNG is injected to the natural gas pipeline where it is produced, and "wheeled" to other locations.

What is wheeling? It's when you produce the gas in one location, and use it somewhere else. Dad's Oatmeal Cookies in Toronto uses RNG supplied by Bullfrog Power from the Terrebonne landfill near Montreal through an audited accounting process of RNG injection and usage. While the cookie plant doesn't use the actual molecule of RNG produced in Quebec, this "wheeling" of the gas is considered a legitimate approach to production and consumption of RNG. In the case of a municipality or food company, the wheeled gas might still be produced locally, but rely on a few kilometres of the natural gas pipe grid to wheel the gas to the end use location.

See the Surrey and London case studies below.

WASTEWATER TREATMENT (WWT)

Some wastewater treatment plants process biosolids through anaerobic digestion (AD), which produces biogas that can be upgraded to RNG. Most WWT plants in Ontario flare the biogas that is produced instead of capturing it for energy recovery. This large source of biogas represents a significant opportunity to increase the production of RNG from biogas which is already being produced.

See the Hamilton and Niagara case studies below.

INTEGRATED SOURCES

Landfills owned by municipalities or waste management companies provide opportunities to integrate LFG processing with the anaerobic digestion of other municipal organic wastes.

For example, biogas from a municipal landfill site could be expanded to accommodate biogas systems for SSOs. The two sources of biogas, LFG and SSO, could share infrastructure needed to upgrade biogas to RNG and connect to the natural gas grid.

Similarly, wastewater treatment and SSO treatment can be combined to share infrastructure and improve efficiencies. See the Saint-Hyacinthe case study below for details.

Business Case Considerations

When studying the business case for producing RNG, consider the gas volumes the material can produce, and the cost to do so. Then consider what costs this production is replacing to make a decision.

Consider the following volumes and outputs gathered from existing and proposed municipal systems:

- Generally, one tonne of SSO generates 110 cubic metres of biogas. Depending on the methane content of the biogas, which can range from 50-65% methane, depending on the material being processed, one tonne of SSO can produce about 70 cubic metres of RNG.

- For wastewater treatment, for each 250 m^3/day of sludge treated, an anaerobic digester will produce 1,900 m^3/day of biogas.[22]

- At Hamilton's WWT, biogas generation rates were based on 0.9 m^3 of biogas generated for each 1.0 kg of volatile solids (VS) destroyed in digestion. In 2014, it injected 536,062 m^3, or 20,290 GJ into the Union Gas grid at a rate of 750 Nm^3/hr or 500 SCFM. Volumes varied significantly from month to month. Revenue was over $116,000 in 2014. The business case in future will be strengthened as they shift to displacing gasoline and diesel for transit vehicles that will be CNG and RNG fueled.

- Niagara Region's wastewater treatment plant is expected to produce 84,000 gasoline gallon equivalent (GGE) per year of RNG and would reduce the municipality's annual GHG emissions by 1,000 tonnes. The RNG generated would fuel 60 fleet vehicles that would be converted to run on CNG/RNG.[23] The total capital cost of the pilot project is estimated at $1.1 million for the first year and an additional $200,000 annually for the subsequent 4 years. Payback is anticipated at 9.5 years.[24]

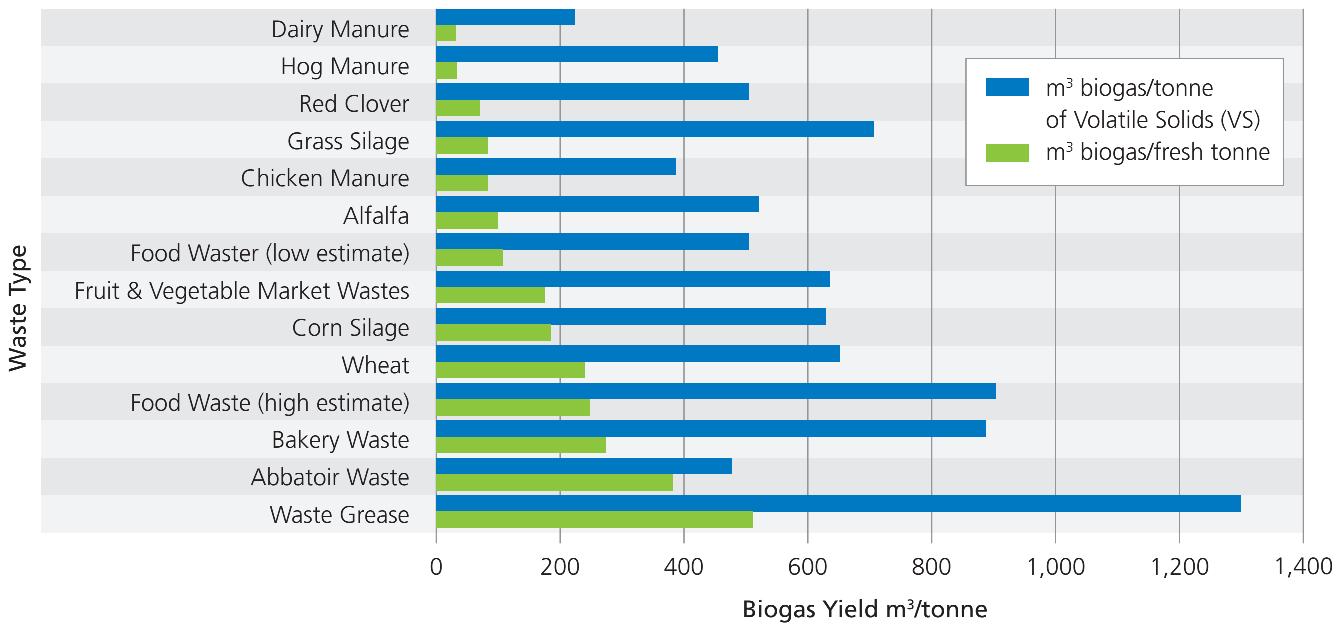
- Progressive Waste Solution's Terrebonne landfill near Montreal is processing approximately 10,000 cubic feet per minute (SCFM) of incoming landfill gas. The energy generated is sufficient to keep the equivalent of 1,500 trucks on the road for 20 years, or the equivalent of a reduction in fossil-fuel dependence of 350,000 barrels of oil per year. The new plant will also result in avoidance of greenhouse gas emissions of as much as 1.2 million tonnes of carbon dioxide (CO_2) over a 10-year period.

There are many variables with RNG production which limit generalizations that can be made about the business case. When investigating the business case for your organization, it is recommended that you connect with consultants, technology suppliers, and representatives from municipalities or industrial biogas operations that have direct experience with these systems. A list can be supplied by the Canadian Biogas Association upon request.

22 Data provided by CEM Engineering
23, 24 The Regional Municipality of Niagara (2014).
Request for Proposal - Design of Biogas to Biomethane to Compressed Natural Gas Project: Port Dalhousie Wastewater Treatment Plant

In addition to the outputs related to SSO and WWT above, the chart below may be useful as well. A cubic metre of biogas will produce about 0.65 cubic metres of RNG.

BIOGAS YIELDS OF DIFFERENT WASTES



Source: Regenerate Biogas

Biogas Purification Technology Overview

Biogas generated through anaerobic digestion or in landfills includes gases and moisture which need to be removed in order to inject it into the pipeline or used in a vehicle engine. These include carbon dioxide, water, hydrogen sulfide, oxygen, nitrogen, ammonia, siloxanes, and particulate matter. Concentrations depend on the compositions of the organic materials used to create the biogas.

The most widely used technologies for biogas upgrading are the following:

1. **Pressure swing adsorption.** This technology purifies the gas by way of adsorption of impurities on active coal or zeolites.
2. **Water scrubbing.** Water (or another liquid such as alcohol) is used to bind carbon dioxide. This is a form of physical absorption, and is also called pressurized water wash.
3. **Chemical absorption.** Chemical absorption is comparable to water absorption. A liquid such as amine is chemically bonded to the carbon dioxide. In order to recycle the solution, a heat treatment is applied.
4. **Membrane separation.** Methane can be separated from carbon dioxide using semi-permeable membranes. The force can be a pressure difference, a concentration gradient, or an electrical potential difference.
5. **Cryogenic separation.** Trace gases and carbon dioxide are removed by cooling down the gas in various temperature steps.

The International Energy Agency's *Biogas upgrading technologies – developments and innovations* document is also a useful resource.

Connection Charges and Quality Expectations

If you are planning to use the natural gas pipeline to store or transport your RNG, you will need to enter into an agreement with the local distribution utility. For a listing of gas utilities across the country, visit the Canadian Gas Association website. You will be expected to pay all of the costs of connecting your facilities to the natural gas distribution system. Typically, the utility will be able to define the physical connection requirements necessary to inject RNG into its system. Typically, the utility will require the installation of a producer station which includes components for billing measurement, pressure regulation, odourization, and gas quality monitoring, as well as a length of interconnecting pipe necessary to tie into the nearby distribution system.

The charge is dependent on the site-specific facilities requirements and can vary based on the length of piping required to connect to the system, outlet delivery pressure, and flow rate from the supplier into the system.

The natural gas utility also regulates the quality of all gas entering its distribution system. Producers need to follow guidelines laid out by the utility. The Canadian Gas Association has published a *Biomethane Guideline* highlighting a general consensus of gas quality expectations for RNG by the utilities across Canada.

Permits, Approvals and Safety

Government permits and approvals required for biogas and upgrading systems vary from province to province.

British Columbia Ministry of Environment requires three permits for biogas systems: effluent; air; and solids. Permits are issued by the regional offices, and are site-specific.

In Ontario, an *Environmental Compliance Approval* from the Ministry of the Environment and Climate Change is required for RNG production facilities. If electricity is not being generated for connection to the electricity grid, a *Renewable Energy Approval* is not required.

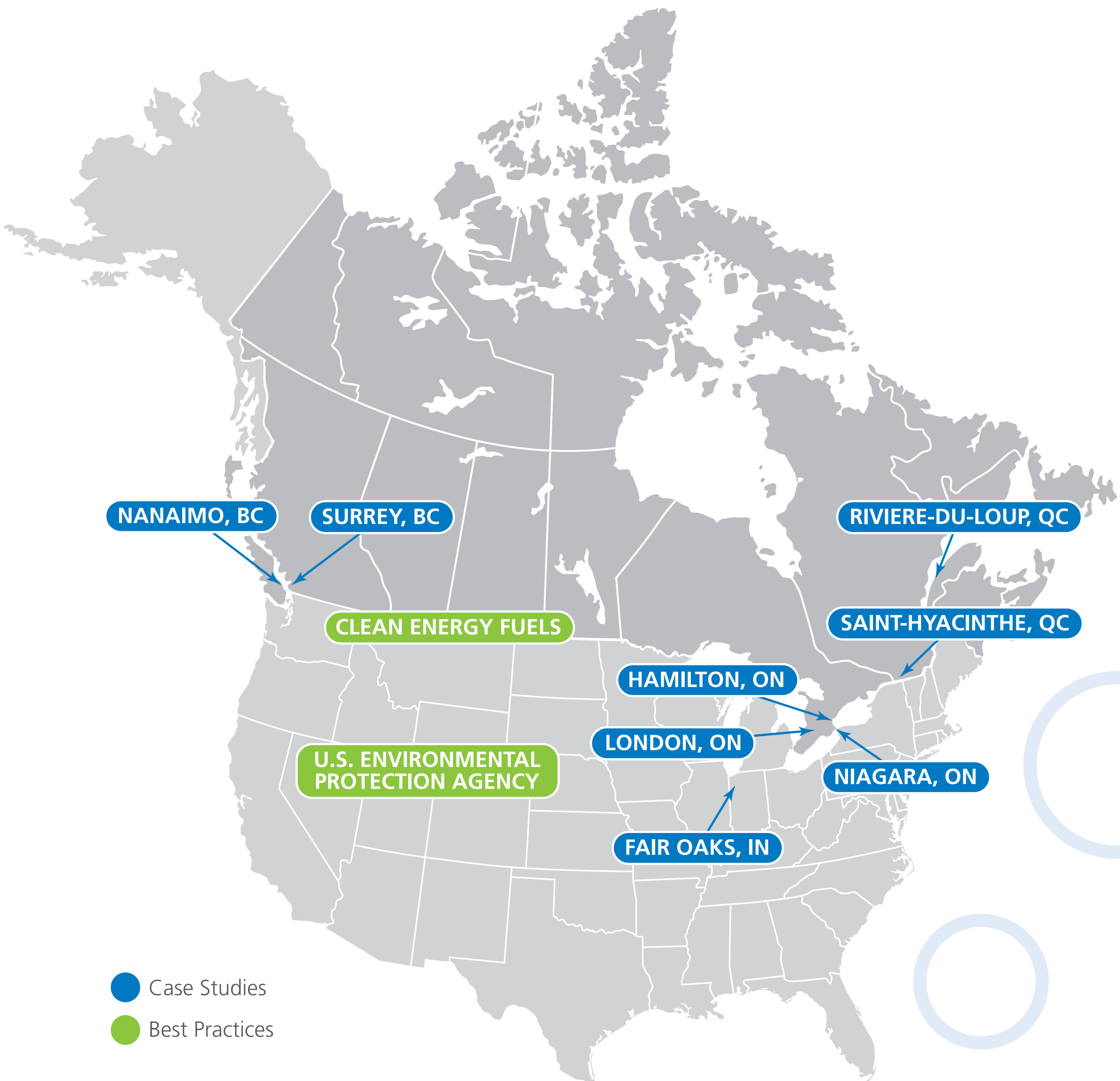
Within Ontario, RNG production facilities also require approval from the Technical Standards and Safety Authority (TSSA). The TSSA enforces Ontario's *Technical Standards and Safety Act, 2000* which covers industry sectors such as boilers and pressure vessels, propane and other fuels and equipment, including RNG. Operators need to consult the *Compressed Gas Regulation (O. Reg. 214/01)* and *Gaseous Fuels Regulation (O. Reg. 212/01)* to understand the certification and operational requirements, registration processes and other pertinent safety information. The TSSA has published a number of relevant code adoption documents for these sectors, which updates the standards and requirements. Of special note is that the TSSA plans on adopting a new ANSI/CSA code that will be published in late 2015: *ANSI/CSA B149.6-15: Code for Digester Gas, Landfill Gas and Biogas Generation and Utilization*. For further information on TSSA requirements for RNG, go to the TSSA website.

In other provinces, consult with your Ministry of Environment and provincial safety authority regarding permits and approvals required.

Municipal building permits are also required. Developers report these are not difficult to obtain.

Case Studies and Best Practices

Case studies from Ontario, British Columbia and the United States demonstrate the feasibility of biogas generation from organic waste sources. These examples illustrate the various applications for biogas and how these projects have been implemented by municipalities and private sector entities. These case studies highlight the potential for biogas projects to generate revenue, provide cost savings, and reduce greenhouse gas (GHG) emissions.



HAMILTON, ONTARIO: CANADA'S FIRST WASTEWATER PLANT INJECTING RNG

The City of Hamilton completed a biogas cogeneration plant at the Woodward Avenue Wastewater Treatment Plant in 2006. The project was undertaken to: generate revenue, reduce costs and increase environmental benefits. Establishing the facility allowed Hamilton to lower its energy consumption, increase its energy efficiency, reduce GHG emissions, minimize external energy requirements for the wastewater plant and increase the amount of renewable energy that is locally produced in Hamilton.[25]

When a series of process upgrades were undertaken at the plant in 2012, additional biogas was produced and a biogas purification unit was installed to purify the biogas to renewable natural gas (RNG). The purifier is based on a water scrubbing technology rated at a capacity of 750 Nm3/hr (500SCFM). This RNG is injected directly into the regional Union Gas distribution system and complements the cogeneration unit as a diversified source of revenue for the City.[26]

Currently, Hamilton is in the process of upgrading its wastewater treatment facility again through a *Biosolids Management Project*. The proposed $111 million dollar project is being undertaken in the form of a public private partnership with support from P3 Canada. As part of this project, Hamilton will be seeking innovation from industry experts to further maximize their energy recovery and utilization from their biosolids treatment system to bring a long term sustainable *Biosolids Management Program* to their community. In addition, the City of Hamilton will be replacing many of its transit system buses, to CNG and will blend in RNG produced at the wastewater treatment plant.[27]

25 *Environment Canada (2008).* *Hamilton Renewable Power Incorporated*
26, 27 *Water Tap Ontario (2013).* *Moving From "Cost Centre" to "Profit Centre": Hamilton Water*

NANAIMO, BRITISH COLUMBIA: PROVINCE'S FIRST LANDFILL FUELING WASTE TRUCKS

The Nanaimo Bioenergy Centre, located in the Regional District of Nanaimo, uses its landfill gas (LFG) in a range of ways.

Cedar Road Bioenergy Ltd., a member of the Sun Current group, owns and operates the gas utilization facility at the Nanaimo Landfill under a private public partnership agreement with the Regional District of Nanaimo and the BC Bioenergy Network.[28]

The facility became operational in March 2009, producing 1.4 MW of electricity from LFG collected at the Nanaimo Landfill. In 2012, the facility reduced GHG emissions by 28,113 tonnes.[29] The small-scale LFG conversion facility was constructed over two phases. The actual installed cost for Phase 1 was $4.8 million. Operation and maintenance costs are $600,000 per year and include debt interest payments.[30]

The project received funding from the BC Government Innovative Clean Energy Fund, the Federation of Canadian Municipalities, and the BC Bioenergy Network.[31]

Phase 2 started in 2012 and involved a $2.3 million expansion and upgrade of the facility, including a double membrane biogas storage system.[32] Phase 2 has increase net output efficiency by 30%. A new biogas cleaning system has also been installed, which will enable the facility to expand to other LFG uses, such as RNG transportation fuel.[33] The partners anticipate operation of this third phase in 2016.

The improvements and expansion of the Nanaimo Bioenergy Centre are expected to increase annual revenue by $238,000.[34]

SURREY, BRITISH COLUMBIA: CANADA'S FIRST MUNICIPALITY TO CLOSE THE LOOP

The City of Surrey is building an *Organic Waste Biofuel Processing Facility*, which will be a sustainable closed loop system. Organic waste will be used to produce RNG, which will power Surrey's waste collection vehicles, thus creating the closed loop system. The *Organic Waste Biofuel Processing Facility* is expected to be operational in 2016-2017.[35]

The facility will be developed as a *Public Private Partnership*.[36] The City of Surrey has entered a $9 million waste contract with Progressive Waste Solutions for organic waste collection using CNG trucks that will be powered by the RNG generated at the facility.[37] The Government of Canada, through the *P3 Canada Fund*, will contribute up to 25% of the capital costs.[38]

The plan will cut operating costs, reduce air pollution and GHG emissions, and serve as an integrated model for organic waste management for communities across North America. Additional information on the Surrey, BC waste management plan is available in the *Canadian Biogas Study Summary* document.

28, 29, 30 Global Methane Initiative. (2012). Nanaimo Bioenergy Centre LFG Utilization Facility
31 BC Ministry of Community and Rural Development. (2010). Integrated Resource Recovery Case Study: Regional District of Nanaimo Landfill Gas Recovery and Utilization
32 Global Methane Initiative. (2012). Nanaimo Bioenergy Centre LFG Utilization Facility
33 Chan, K. (2013). A New Kind of Angel: A Private-Public Partnership Examined
34 Global Methane Initiative. (2012). Nanaimo Bioenergy Centre LFG Utilization Facility
35, 36 City of Surrey (2015). Organic Biofuel Facility
37 Sinoski, K. (2011). Surrey Signs 'Sustainable' Garbage Contract
38 City of Surrey (2015). Organic Biofuel Facility

SAINT-HYACINTHE, QUEBEC: PRODUCING RNG FROM MULTIPLE WASTE STREAMS

The City of Saint-Hyacinthe and Gaz Métro reached an agreement in 2014 for the purchase and injection of renewable natural gas produced in the city's biogas facility. Under the agreement, Gaz Métro will purchase up to 13 million cubic metres of RNG per year for a 20-year period from Saint-Hyacinthe. Saint-Hyacinthe implemented the collection of organic waste in 2007, and is installing new anaerobic digesters at the City's wastewater treatment plant. The existing digesters, which were used to treat sewage sludge, are being upgraded to be able to accept multiple waste streams.

The city is expanding organic waste collection to in the communities of Les Maskoutains and Acton. The bin contents will also be processed at the anaerobic digestion plant in Saint-Hyacinthe, thus avoiding transport to external composting sites.

Saint-Hyacinthe has begun recycling organic matter from local agri-food businesses at the facility, which can now dispose of their organic waste in an environmentally friendly manner and at a lower cost.

For the city of Saint-Hyacinthe, the project's total cost is over $48 million, provided in equal parts by the city and subsidies from the federal and provincial governments. In a few years, the city will amortize and then self-finance the cost of constructing its organic waste reclamation and biogas plants.

"In 2016-2017, once our facility is fully operational, the city will make a significant annual profit [from the sale of the RNG to Gaz Metro], including savings of a half-million dollars in lower fuel and heating costs for our municipal buildings and vehicles," said Saint-Hyacinthe Mayor Claude Corbeil. "By maximizing the reclamation of organic waste from brown bins, residents and agri-food businesses are taking a positive step for the environment and generating a source of income that the city will be able to use to improve services. Saint-Hyacinthe is proud to innovate with such green, profitable and sustainable practices."

RIVIERE-DU-LOUP, QUEBEC: PRODUCING RENEWABLE LNG FROM RESIDENTIAL SSO

Gaz Metro is building a public liquified renewable natural gas fueling station in Riviere-du-Loup, Quebec. The agreement with the municipality covers the purchase of liquefied RNG produced by the anaerobic digestion plant of SSO at Riviere-du-Loup, approximately 200 kilometres northeast of Quebec City, and the operation of a new liquefied natural gas (LNG) fueling station, intended for the heavy transport market.

The project marks a new stage in the 'Blue Road' project, which supplies liquefied natural gas in the corridor between regions of Quebec and the Greater Toronto Area (GTA) that sees high volumes of heavy trucks.

According to Gaz Metro, the annual production of liquefied RNG at the Riviere-du-Loup plant is estimated at three-million cubic metres (m^3).

LONDON, ONTARIO: STUDYING OPTIONS FOR RESIDENTIAL SSO TO PRODUCE RNG

The City of London has established a *Community Energy Action Plan* for 2014 to 2018. The goal of the plan is to increase the local economic benefit of sustainable energy use, while reducing waste and GHG emissions, consistent with Ontario's GHG emissions reductions targets.

One of the key strategies outlined in the London *Action Plan* is to work with Union Gas to promote the use of CNG and RNG as a substitute for diesel fuel in trucks and transit vehicles.[39]

The City of London is currently studying the feasibility of collecting SSO, and processing it in a biogas system to use as a vehicle fuel.

NIAGARA, ONTARIO: FUELING TRUCKS FROM WASTEWATER

The Regional Municipality of Niagara is planning a RNG pilot project at its Port Dalhousie Wastewater Treatment Plant. The RNG will be used to fuel the division's fleet vehicles and any surplus will be injected into the natural gas grid.[40]

The project is expected to: produce 84,000 gasoline gallon equivalent (GGE) per year and would reduce the municipality's annual GHG emissions by 1,000 tonnes. The RNG generated would fuel 60 fleet vehicles that would be converted to run on CNG/RNG.[41]

The total capital cost of the pilot project is estimated at $1.1 million for the first year and an additional $200,000 annually for the subsequent 4 years. Payback is anticipated at 9.5 years.[42]

RNG FUELS MILK TRUCK FLEET FROM FAIR OAKS DAIRY, INDIANA

Fair Oaks Dairy produces biogas from manure through anaerobic digestion. The biogas that is produced on site generates enough electricity for the farm. The remaining biogas is upgraded to RNG for use as transportation fuel. The manure from 11,000 dairy cows is anaerobically digested to produce biogas that is approximately 60% methane. The biogas is purified, compressed and upgraded to 98% methane.[43] The gas is further compressed to 4,000 psi at the Fair Oaks fueling station, at which point it can be used to fuel CNG vehicles or be added to the natural gas pipeline.[44]

39 City of London (2014). Community Energy Action Plan
40, 41, 42 The Regional Municipality of Niagara (2014).
Request for Proposal - Design of Biogas to Biomethane to Compressed Natural Gas Project: Port Dalhousie Wastewater Treatment Plant
43 Anaergia (2013). Anaergia Provides Renewable Fuel for Milk Tanker Fleet from Manure Biogas
44 United States Environmental Protection Agency (2012). Fair Oaks Dairy: Digester 1

A fueling station supplies the RNG to fuel a fleet of 42 milk trucks operated by Fair Oaks Farms and AMP Americas, which is a transportation company that focuses on displacing liquid fuels with CNG. The renewable fuel avoids the consumption of diesel fuel for their daily milk deliveries. The deliveries cover more than 32,000 km per day across the Midwest United States. The project is saving $10,000 per day in fuel costs,[45] and is expected to reduce fleet GHG emissions by 40,000 tonnes per year, which is the equivalent of removing 7,000 passenger cars from the road.[46]

The project received government grants to convert trucks to natural gas, which reduced the payback period. Grants and loan guarantees came from the U.S. Department of Energy, U.S. Rural Development, and the Clean Cities Coalition of Greater Indiana.[47]

BEST PRACTICE: RNG AT PRICE PARITY THROUGH CLEAN ENERGY FUELS

Clean Energy Fuels produces the first commercially available RNG vehicle fuel. Clean Energy Fuels has named its product 'Redeem'. Clean Energy Fuels is North America's largest provider of natural gas fuel for transportation, fueling over 30,000 vehicles each day at over 350 fueling stations throughout Canada and the United States.

Clean Energy Fuels produces Redeem from methane gas that is collected from organic waste sources, such as landfills and farm-based biogas systems. The gas is then purified and compressed to pipeline specifications. The RNG enters the interstate fuel pipeline and is distributed across the country. The RNG produced by Redeem is available at fueling stations for use by CNG and liquefied natural gas (LNG) vehicles. Clean Energy Fuels offers the CNG and LNG Redeem fuel at the same price as conventional natural gas.[48]

BEST PRACTICE: UNITED STATES ENVIRONMENTAL PROTECTION AGENCY RENEWABLE FUEL STANDARD

The Environmental Protection Agency (EPA) is responsible for developing and implementing regulations concerning minimum renewable fuel volumes for transportation fuel sold in the United States. The *Renewable Fuel Standard* (RFS) is a renewable fuel volume mandate that requires that 36 billion gallons of renewable fuel is blended into transportation fuel by 2022.[49]

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 waste-water treatment facility digesters, agricultural digesters, and other organic wastes.[50]

45 Biogas Association (2013). Farm to Fuel: Developers' Guide to Biomethane as a Vehicle Fuel
46 Anaergia (2013). Anaergia Provides Renewable Fuel for Milk Tanker Fleet from Manure Biogas
47 Biogas Association (2013). Farm to Fuel: Developers' Guide to Biomethane as a Vehicle Fuel
48 Clean Energy (2013). Redeem: Fueling a Renewable Future
49 United States Environmental Protection Agency (2014). Renewable Fuel Standard
50 Dodge, E. (2014). New Biogas Rules in the RFS

RNG Technology Roadmap

The Canadian Gas Association has published a *RNG Technology Roadmap*, which was written by CanmetENERGY with participation from leading RNG experts from across Canada, including representatives from Canada's natural gas utilities, biogas producers, technology supplies, academic and research groups, and federal and provincial governments. The roadmap identifies market barriers, technologies, research and development, and marketing and investment decisions needed to support the development of a RNG sector in Canada by 2020. It recommends exploring the use of RNG for vehicles.

Natural Gas & Energy Conversions

Convert from	Convert to	Multiply by
cubic foot	cubic metre	0.028328
cubic metre	cubic foot	35.314667
gigajoule	cubic metre	26.8
million cubic feet	1,000 cubic metres	28.328
1,000 cubic metres	million cubic feet	0.0353
BTUs	Joule	1054.615
Joule	BTUs	0.0009482
million BTUs	Gigajoule	1.054615
gigajoule	million BTUs	0.948213

Source: www.energy.gov.ab.ca/about_us/1132.asp

Glossary

Anaerobic Digestion (AD): A series of biological processes in which microorganisms break down biodegradable material in the absence of oxygen. One of the end products is biogas, which is combusted to generate electricity and heat, or can be processed into renewable natural gas and transportation fuels.

Biogas: A gaseous emission from the anaerobic digestion of organic matter. Biogas is principally a mixture of methane (CH_4) and carbon dioxide (CO_2) along with other trace gases.

Biomethane: Biogas that has been compressed and purified. Biomethane is a renewable form of natural gas that is interchangeable with fossil fuel derived natural gas. Biomethane is referred to in this document as renewable natural gas (RNG). The two terms are used interchangeably.

Biosolids: Organic materials resulting from the treatment of sewage sludge.

Compressed Natural Gas (CNG): A readily available alternative to gasoline that is made by compressing natural gas to less than 1% of its volume at standard atmospheric pressure.

Greenhouse Gases (GHG): Gases that trap heat in the atmosphere and are the principal cause of climate change.

Landfill Gas (LFG): A form of biogas that is a by-product of the decomposition of organic waste buried in landfills.

LNG: Liquified natural gas is natural gas (predominantly methane, CH_4) that has been converted to liquid form for ease of storage or transport. It takes up about 1/600th the volume of natural gas in the gaseous state.

Natural Gas Vehicle (NGV): A vehicle that uses compressed natural gas as an alternative to conventional fuels, such as gasoline and diesel. Natural gas vehicles can also be fuelled by renewable natural gas (RNG).

Renewable Natural Gas (RNG): Biogas that has been compressed and purified. A renewable form of natural gas that is interchangeable with fossil fuel derived natural gas.

Source Separated Organics (SSOs): Organic wastes, including food wastes from residential, commercial and industry sources. These organic wastes are separated from other landfill materials and can be used to generate biogas through anaerobic digestion.

Wastewater Treatment (WWT): The treatment of wastewater produces biosolids which can be processed through anaerobic digestion to produce biogas.

Well-to-tank, and well-to-wheels: Well-to-wheel is the specific lifecycle analysis used for transport fuels and vehicles. The analysis is often broken down into stages entitled "well-to-station", or "well-to-tank", and "station-to-wheel" or "tank-to-wheel", or "plug-to-wheel". The first stage, which incorporates the feedstock or fuel production and processing and fuel delivery or energy transmission, is called the "upstream" stage; while the stage that deals with vehicle operation itself is sometimes called the "downstream" stage. The well-to-wheel analysis is commonly used to assess total energy consumption, or the energy conversion efficiency and emissions impact of marine vessels, aircraft and motor vehicles, including their carbon footprint, and the fuels used in each of these transport modes.

Resources

Biogas Association (2014). Organic Materials Primer

The Primer provides a brief historic overview of anaerobic digestion (AD), and an outline of the AD process; challenges faced by the AD sector, and opportunities related to capitalizing on the food waste opportunity and creating jobs; regulations that govern the AD sector, and testing and certification requirements; pathways that organic material can follow, depending on which type of AD system accepts the material; and what is being done differently in other jurisdictions, including Quebec, NS, the U.S. and Europe, where restrictions are in place on how organic material can be treated and disposed.

Biogas Association (2012 and 2013). Farm to Fuel: Developers' Guide to Biomethane; and Farm to Fuel: Developers' Guide to Biomethane as a Vehicle Fuel

The guides were created to build the production of biomethane in Canada. The Guide helps farmers determine if biomethane production is a good fit for their farm and operations. For those farmers considering developing biogas systems, and upgrading the biogas to biomethane, the Guide walks them through the planning process, offering a check-list of questions to ask relevant technology and service providers. It also alerts farmers to important considerations, such as feedstock, financing, permits and safety.

Biogas Association (2014). Progressive Waste Solutions

Clarke S. and J. DeBruyn (2012). Vehicle Conversion to Natural Gas or Biogas

Union Gas Ltd. (2014). Natural Gas for Fleet Vehicles: The Answer to Rising Energy Prices and Lower Emissions Targets

Explores the use of compressed natural gas for fleet vehicles and explains the economic and environmental benefits.

Natural Resources Canada (2010). Natural Gas Use in the Canadian Transportation Sector-Deployment Roadmap

Explains the market for natural gas vehicles in Canada, the outlook for natural gas, business case modelling, and identifies challenges and opportunities for the use of natural gas in the transportation sector.

Quest (2012). Renewable Natural Gas: The Ontario Opportunity

This business case study examines the potential growth of renewable natural gas (RNG). The case study demonstrates that the creation of an RNG industry in Ontario could bring significant benefits to the province and contribute to meeting the Government of Ontario's greenhouse gas, energy efficiency and clean air targets.

Crittenden, G. (2014). Natural Gas Vehicles for the Waste and Recycling Industry;
Milner, A. (2014). Factory-Built Natural Gas Trucks

These articles are from the February/March (2014) issue of Solid Waste and Recycling Magazine, which featured a natural gas vehicles supplement section. The specific focus of the articles is the use of natural gas vehicles for the waste and recycling industry. The articles featured include an analysis of economic payback as well as information on the Cummins Westport engines for natural gas trucks.

Milner, A. (2013). Compressed Natural Gas

Alicia Milner is president of the Natural Gas Vehicle Alliance. In this article, she discusses the use of compressed natural gas for the waste and recycling industry.

Cummins Westport (2015). Heavy-Duty Natural Gas Engines

Cummins Westport supplies two natural gas engines, ISL G and ISX12 G, which are suitable for municipal return-to-base fleet operations.

Canadian Natural Gas Vehicle Alliance (2015). Renewable Natural Gas

The Canadian Natural Gas Vehicle Alliance website contains information on: commercial vehicle and station technologies, environmental benefits, Canada's natural gas vehicle industry, as well as links to other useful resources.

United States Environmental Protection Agency (2014). Renewable Fuel Standard

Environment Canada (2008). Hamilton Renewable Power Incorporated

United States Environmental Protection Agency (2014). Greenhouse Gas Equivalencies Calculator

Water Tap Ontario (2013). Moving From "Cost Centre" to "Profit Centre": Hamilton Water

City of London (2014). Community Energy Action Plan

Pollution Solutions (2014). Organic Waste-to-Energy Project Illustrates Global Potential of Biogas to Provide Green Power

De Bono, N. (2011). Biogas Project Revived

The Regional Municipality of Niagara (2014). Request for Proposal – Design of Biogas to Biomethane to Compressed Natural Gas Project: Port Dalhousie Wastewater Treatment Plant

Global Methane Initiative. (2012). Nanaimo Bioenergy Centre LFG Utilization Facility

BC Ministry of Community and Rural Development (2010). Integrated Resource Recovery Case Study: Regional District of Nanaimo Landfill Gas Recovery and Utilization

City of Surrey (2015). Organic Biofuel Facility

Progressive Waste Solutions (2014). Leading the Conversion to Natural Gas for Waste and Recycling Fleets in Canada

Progressive Waste Solutions (2014). We are Revving up our CNG Fleet Conversion Program

Anaergia (2013). Anaergia Provides Renewable Fuel for Milk Tanker Fleet from Manure Biogas

United States Environmental Protection Agency (2012). Fair Oaks Dairy: Digester 1

Clean Energy (2013). Redeem: Fueling a Renewable Future

Canadian Biogas Association

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ENBRIDGE GAS INC.

Undertaking Response to ED

To advise what Enbridge believes the best estimates are and why, including a comparison with the marginal abatement cost curve report.

Response:

The figures set-out in the table below are based on the Company's discussions with potential Ontario RNG producers. The target commissioning dates of these facilities range from 2020 to 2025.

Potential Ontario Renewable Natural Gas Production Facilities Known to Enbridge Gas				Potential based on MACC (10^6m^3)[1]
Feedstock / Biogas Source	**Potential Number of Facilities**	**Potential Annual Production (10^6m^3)**	**Estimated Annual Production (10^6m^3)**	
Anaerobic Digestion & Gasification[2]	24	210	101	443
Landfill	8	161	149	113
Wastewater Treatment Plants	5	31	13	71
Totals	**37**	**402**	**262**	**627**

[1] Ontario Energy Board, "Marginal Abatement Cost Curve for Assessment of Natural Gas Utilities' Cap and Trade Activities" (EB-2016-0359), Table 17

[2] Enbridge Gas has combined the potential volumes for source separated organics ("SSO"), animal manure and agricultural residue as shown in the MACC to align with the Company's estimate for anaerobic digestion + Gasification. These feedstocks can be converted to RNG via Aanaerobic digestion or Gasification

ENBRIDGE GAS INC.

Undertaking Response to ED

To provide the calculation for the dollar per tonne amount in SEC 15

Response:

The cost of avoided carbon was based on the data provided in Exhibit I.STAFF.10, and is calculated as follows:

Effective Cost of Avoided Carbon (\$/tCO_2e) =
Forecasted Funds (\$) ÷ Forecasted Emission Reduction (tCO_2e)

Example calculation based on data shown in Exhibit I.STAFF.10 for Year 1:

Effective Cost of Avoided Carbon (\$/tCO_2e) = \$386,090 ÷ 1,143 tCO2e = \$338/tCO_2e

ENBRIDGE GAS INC.

Undertaking Response to ED

To calculate a revised cost per tonne of GHG emissions that includes the GHG emissions of natural gas lost in the environment during extraction, transportation, and distribution.

Response:

As discussed in Exhibit I.PP.4, the preliminary value for the lifecycle carbon intensity of natural gas in the federal Clean Fuel Standard ("CFS"), which is currently under development, is 62 gCO_2e/MJ. This number can be broken out further to 48 gCO_2e/GJ for emissions from end-use combustion, and 14 gCO_2e/MJ related to upstream extraction, processing, transportation and distribution.[1] Based on this information, the upstream natural gas emissions represent approximately an additional 29.2% of avoided emissions, and results in an avoided cost of emissions of \$262/tCO_2e.[2]

[1] The preliminary values were taken from the report submitted by the consultant Earthshift Global to Environment and Climate Change Canada in 2019 and are intended to apply to natural gas across Canada.
[2] Methodology for calculating the $/tCO2e value is discussed in Exhibit JT1.6.

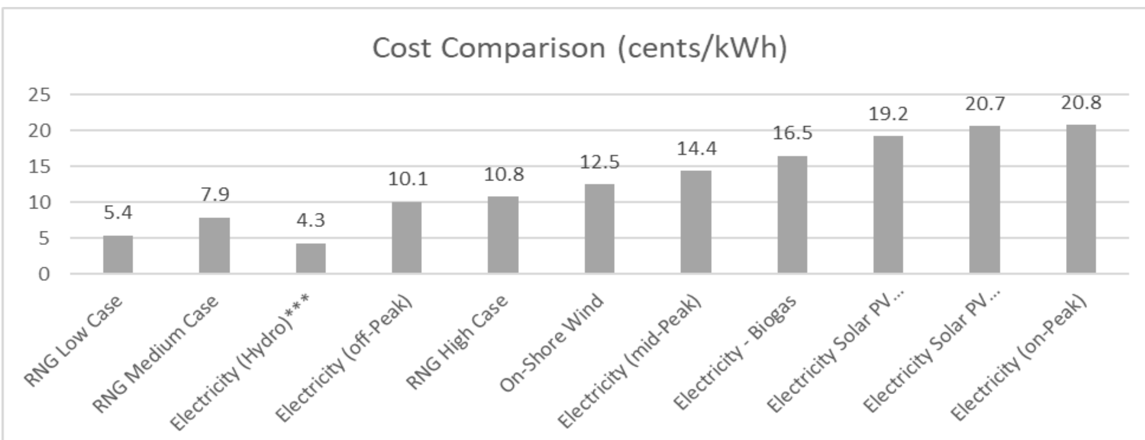
ENBRIDGE GAS INC.

Undertaking Response to ED

To include the OPG price for hydroelectricity in the cost comparison at Exhibit C, Tab 1, Schedule 1. Also, to provide the cost to procure electricity from Hydro-Québec and include it in the cost comparison.

Response:

Please see below the revised cost comparison requested. Enbridge Gas was unable to locate Hydro-Québec's cost charged to Ontario for hydroelectricity supply within the time allowed for the preparation of undertakings.[1]



[1] The documents noted at 1Tr.36 related to Hydro-Québec do not appear to indicate the price charged to Ontario for electricity supply.

Energy Source*	cents/kWh	$/GJ
RNG Low Case	5.4	15.00
RNG Medium Case	7.9	22.00
Electricity (Hydro)***	4.3	11.99
Electricity (off-Peak)	10.1	28.06
RNG High Case	10.8	30.00
On-Shore Wind	12.5	34.72
Electricity (mid-Peak)	14.4	40.00
Electricity – Biogas	16.5	45.83
Electricity Solar PV (non-rooftop)	19.2	53.33
Electricity Solar PV (Rooftop)	20.7	57.50
Electricity (on-Peak)	20.8	57.78

*Electricity prices as of Nov 2019 & FIT/microFIT Price Schedule Jan 2017

**OPG EB-2019-0209 Decision

ENBRIDGE GAS INC.

Undertaking Response to ED

To provide a table comparing RNG low case, RNG high case, and actual

Response:

	cents/m3[1]	$/GJ
RNG Low Case	4.03	15.00
Estimated RNG Cost in the Application	5.64	21.00
RNG High Case	8.06	30.00

[1] Using a conversion factor of 26.853

ENBRIDGE GAS INC.

Undertaking Response to SEC

To provide any analysis of the RNG market over the next five years that Enbridge Gas has received or conducted.

Response:

Please see the attached report: Biogas and Renewable Natural Gas in Ontario: 2019 Market Overview and Outlook, Canadian Biogas Association, June 2019.

Please see also Exhibit JT1.2, which sets out Enbridge Gas's knowledge of RNG supply potential in Ontario.

Biogas and Renewable Natural Gas in Ontario: 2019 Market Overview and Outlook

Canadian Biogas Association

JUNE 2019

Acknowledgements

The Canadian Biogas Association thanks the Independent Electricity System Operator (IESO) for their support of the Empowering Municipal RNG Market Participation Initiative through the Education and Capacity Building Program.

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Connecting Today.
Powering Tomorrow.

The Canadian Biogas Association wishes to thank the stakeholders who participated in the Biogas Think Tank sessions that assisted in the development of this document. These included representatives from municipalities, utilities, project developers and owners and consultants.

Contents

1.0 Foreword: The Growth of Ontario's Biogas Market

With an increasing awareness of climate change, an interest to reduce greenhouse gas emissions, and the need for more sustainable waste management practices, biogas facilities are gaining increasing interest as immediate solutions to these significant issues impacting our local communities and businesses.

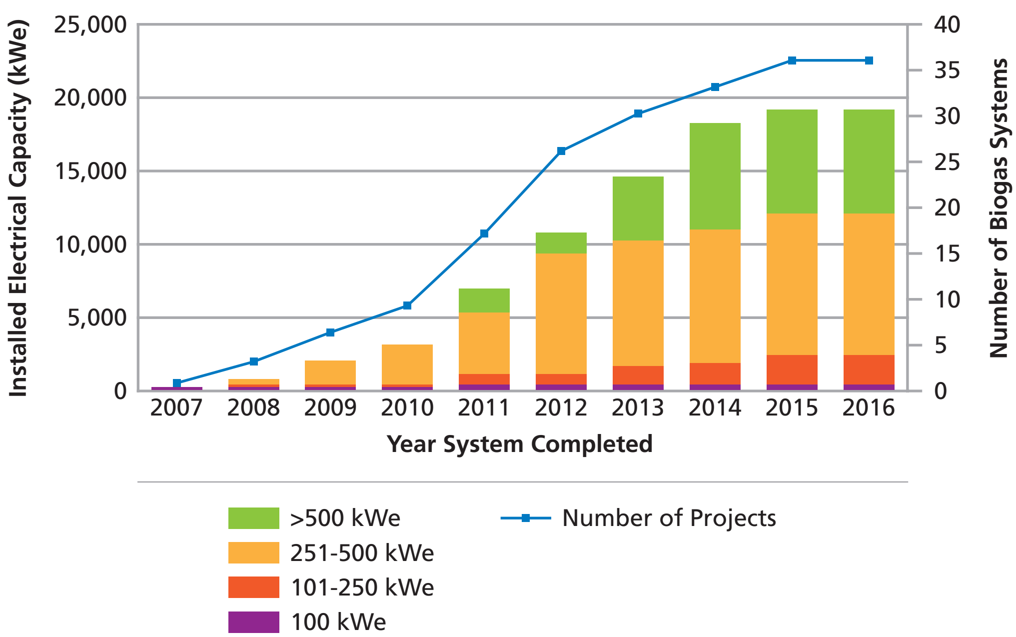
Over the last decade, Ontario has helped lead the development of the biogas and Renewable Natural Gas (RNG) sectors in Canada. It has grown from a few operations to a proven solution across the province in helping to address some of the most pressing issues from climate change to soil degradation.

Today Ontario has 42 operational anaerobic digestion (AD) facilities (32 on-farm and 8 industrial), 45 landfills with landfill gas capture systems, and 76 wastewater treatment facilities with digesters. Figure 1 provides an illustration of the growth particular to anaerobic digestion (AD) facilities between 2007 and 2016. This substantial growth has been driven in part by supportive policies and programs. As Ontario has begun to recalibrate its policies over the last few years, this growth has tapered off. However, there are numerous signals that new policies both at the provincial and federal levels will help to spur new and sustainable growth of the sector.

WHO WE ARE:

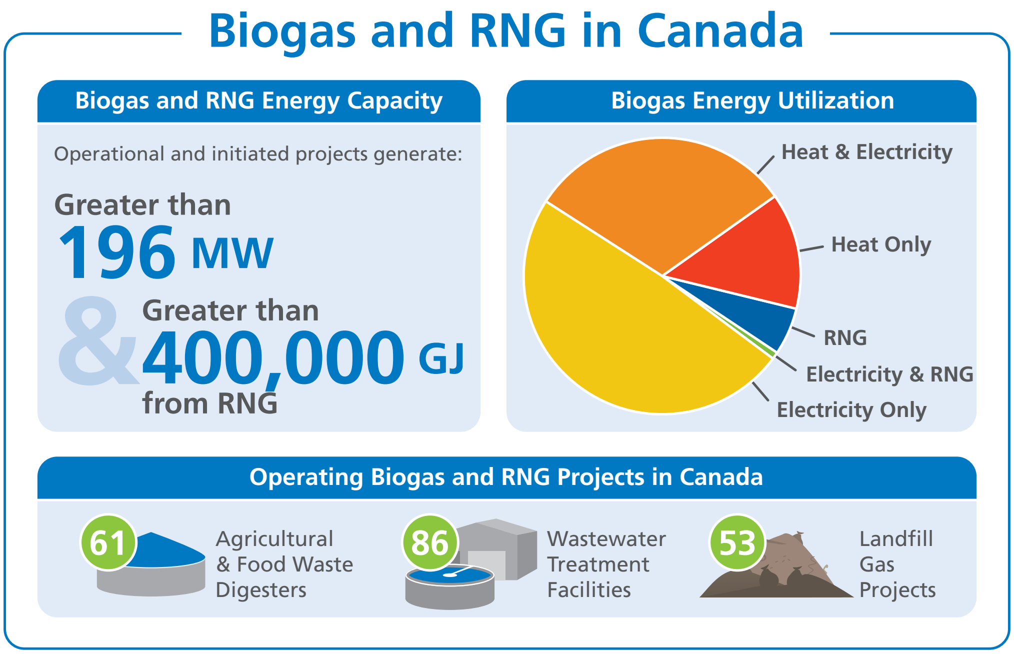
The Canadian Biogas Association (CBA) is the collective voice for the biogas industry, including farmers, municipalities, technology developers, consultants, finance and insurance firms, and other affiliate representatives – all with a focus on building the biogas sector in Canada.

FIGURE 1 – GROWTH OF ONTARIO ANAEROBIC DIGESTION PROJECTS 2007-2016



The biogas and RNG sectors are also seeing new opportunities begin to take shape in other provinces in particular British Columbia, and Québec. Across Canada to date, the biogas sector has demonstrated the technical, financial, logistical and operational capacity with over 60 anaerobic digestion systems, 86 wastewater treatment facilities using anaerobic digestion and 53 landfills with methane collection systems. Figure 2 below illustrates the operational capacity, energy use, and types of biogas and RNG projects in Canada.

FIGURE 2 – 2019 BIOGAS & RNG IN CANADA



Ontario has a significant opportunity to shape the development and utilization of the energy resources as it recalibrates its policy, it can learn from these other jurisdictions, especially with regards to renewable natural gas, combined heat and power systems and transportation fuels. This means providing better support for investment and infrastructure (e.g., reducing regulatory barriers), encouraging value creation (e.g., energy and nutrients), and implementing Ontario's Food and Organic Waste Policy Statement and a disposal ban.

If all of the new demand created for organics processing facilities by Ontario's Food and Organic Waste Policy Statement was met through AD facilities, it would mean more than doubling Ontario's current capacity over the next six years. If Ontario implements a Food and Organic Waste Disposal ban this could easily triple the current capacity.

The focus to date in Ontario has mainly been using biogas to generate electricity but there is significant opportunity to generate RNG. A direct substitute for fossil-based natural gas, RNG could be injected directly into the natural gas grid or used for direct use in any traditional natural gas consuming application. As Ontario continues to move forward to seize new opportunities, it is important to establish a benchmark from which to measure the uptake of biogas and RNG as an alternative, low-carbon energy source.

BIOGAS AND RENEWABLE NATURAL GAS IN ONTARIO: 2019 MARKET OVERVIEW AND OUTLOOK

This report is meant to quantify the development of biogas and RNG production facilities in Ontario reflecting on the past, present and future activity in this space. It builds upon a series of workshops used to better understand the current context, existing barriers and the future potential. The data aggregated in this report establishes a baseline of our understanding, which can be expanded and refined in future reports. This report can be used to support policy, program, and regulatory developments and also provide key stakeholders with the data they need to allow the biogas and RNG sector to deliver on its full potential.

Jennifer Green

Jennifer Green
Executive Director
Canadian Biogas Association

[1]*Quebec, 2030 Energy Policy Action Plan, 2017*

2.0 Context

This report establishes a baseline for the biogas sector in Ontario to measure against future progress. While continuous efforts are made to better understand certain aspects of the sector, this report offers an initial picture. It identifies current capacities, future needs, and barriers hindering the growth and sustainability of the sector.

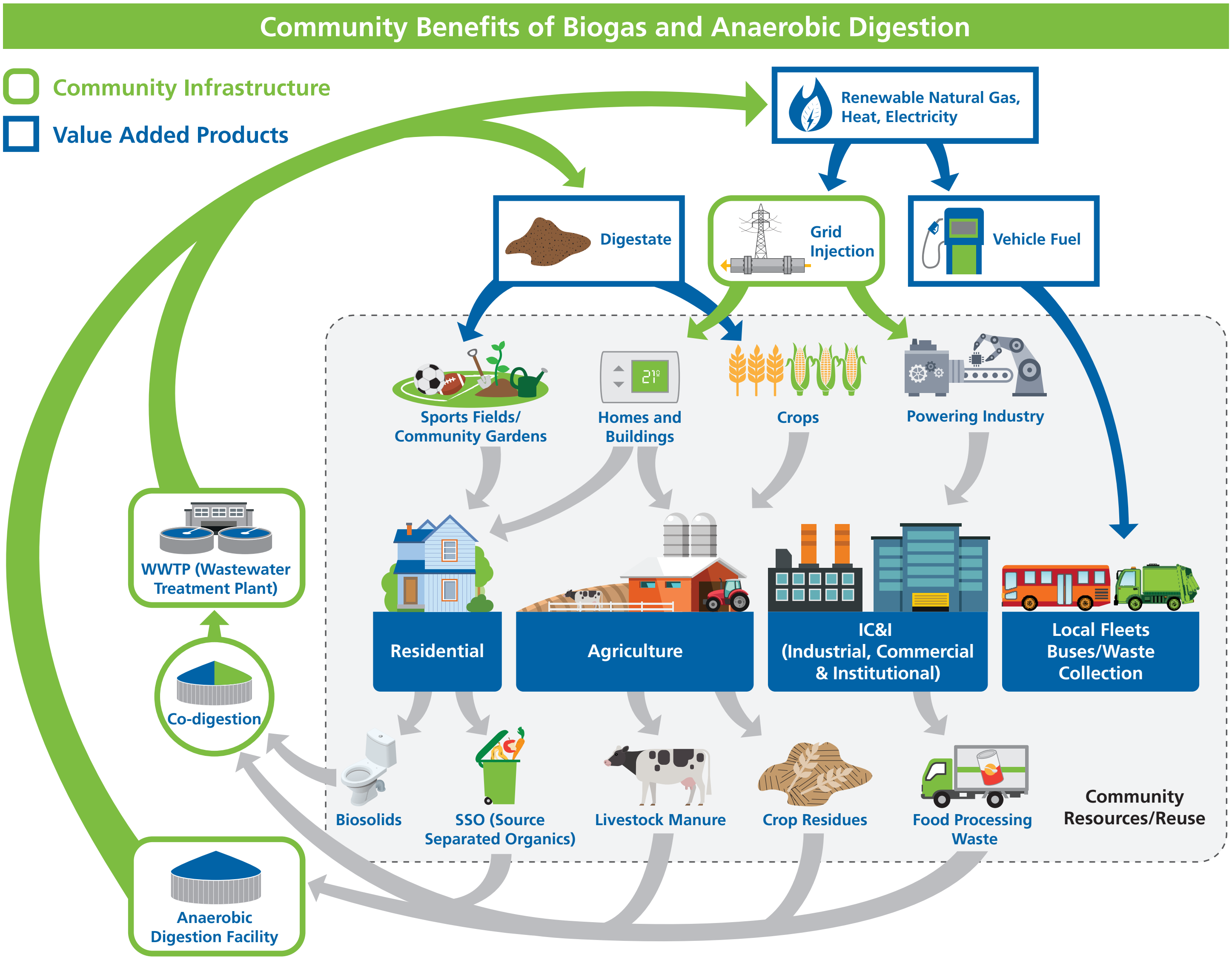
Establishing a baseline of good information is imperative to better understand the full market potential of the biogas and RNG sector, the impact of various government policies, regulations and programs, and, the effectiveness of the sector in dealing with various environmental and economic issues.

2.1 THE BIOGAS SECTOR

Biogas is a renewable fuel used for heat, power and transportation (see Figure 3). It is commonly used around the world to manage materials such as waste and residuals from agricultural and industrial sectors, municipal source separated organics, sewage sludge, and livestock manure.

There has been an increase in interest for standalone biogas facilities that convert organic materials into RNG, referred to as Anaerobic Digestion (AD). The outputs include a nutrient rich soil amendment (i.e., digestate) and a gas (also referred to as biogas) that can be flared or utilized for heat, electricity, fuel or any combination thereof. To date in Ontario, the focus of most AD facilities has been the production of electricity and soil amendments mainly utilized in the agricultural sector.

FIGURE 3 – BENEFITS OF A CIRCULAR ECONOMY: ANAEROBIC DIGESTION BIOGAS



Co-digestion:
A process where energy-rich organic waste materials are added to wastewater digesters with excess capacity. A primary benefit of co-digestion is that is uses existing infrastructure to divert food waste to recover resources.

Anaerobic Digestion:
A biological process that breaks down organics matter in an oxygen-free environment to create biogas.

Value Added Products:
Recovering resources out of materials typically considered waste to create additional beneficial products.

Renewable Natural Gas (RNG):
Biogas can be upgraded to RNG. RNG is carbon neutral and interchangeable with conventional natural gas

Digestate:
Digestate is the product that comes from the anaerobic digestion of organic material and is a nutrient-rich slurry that can be used as a soil amendment, compost and fertilizer to recycle nutrients.

Did you know?
Organic waste is usually processed close to the point of generation with the nutrients and clean energy being directly utilized by the local community, boosting the economy and ensuring sustainability.

Growth in the biogas market has been driven by an increasing focus toward decarbonizing the energy sector, supported by various government policies, regulations and programs. Benefits to promoting the use of biogas include:

- Producing renewable energy (e.g., electricity and RNG);
- Reducing greenhouse gas emissions;
- Mitigating pollution risks (e.g., water, soil and air); and
- Driving investment and jobs including diversifying farm revenue; and
- Reducing odours and pathogens.

Specifically, an increase in AD capacity can also help with a variety of other issues including:

- Preserving landfill capacity;
- Driving investment and jobs including diversifying farm revenue; and
- Improving soil health (i.e., returning nutrients back to the land, increasing crop yields).

With the release of a number of new provincial government documents including the *Made-In-Ontario Environment Plan*, the *Discussion Paper on Reducing Litter and Waste in Our Communities*[1], and *Ontario's Agricultural Soil Health and Conservation Strategy*[2], it is clear these remain priorities and will drive continued government support of the biogas sector as an important solution for years to come.

DID YOU KNOW...

Ontario generates 3.7 million tonnes

of organic waste annually, with only

38%

being diverted

through compost and anaerobic digestion facilities. Landfilled organic materials emit methane –

25x the warming potential of CO_2

The federal government has played a lesser role to date in the development of the sector however, conversations continue related to carbon pricing and climate change policies such as the Clean Fuels Standards which are expected to align with the further development of the biogas sector.

2.2 CONTRIBUTORS TO GROWTH IN ONTARIO

Ontario's biogas market has largely developed over the last decade. There are several exceptions with early landfill gas to energy projects in the City of Toronto and wastewater treatment facilities that have been using AD technology for some time. Most of these early projects were generally flaring the gases, however.

The following Ontario government policies, regulations and programs have had a significant role in shaping the current market:

- In 2006, the Ontario Power Authority (OPA) launched the Renewable Energy Standard Offer Program (RESOP) offering stable pricing under a 20-year contract for renewable energy projects.
- In 2006, an agreement was signed between major municipalities in Ontario and Michigan to stop shipments of municipal waste by the end of 2010. This agreement helped incent many Ontario municipalities to implement curbside green bin programs to preserve local landfill capacity.

[1] *Available at https://prod-environmental-registry.s3.amazonaws.com/2019-03/Reducing%20Litter%20and%20Waste%20in%20Our%20Communities%20Discussion%20Paper_0.pdf.*

[2] *Available at http://www.omafra.gov.on.ca/english/landuse/soil-strategy.pdf.*

- In 2008, O. Reg. 232/98 under the *Environmental Protection Act, R.S.O. 1990* was amended to require new, expanding or operating landfills larger than 1.5 million cubic metres to include landfill gas collection and flaring or use. These requirements were also accompanied by $10 million in provincial funding for municipalities to aid in the implementation of landfill gas capture systems.
- In 2009, Ontario's Feed-In Tariff Program under the *Ontario Green Energy Act* was launched providing a fixed tariff for electricity produced and fed into the grid.
- In 2013, O. Reg. 267/03 under the *Nutrient Management Act, 2002* was amended to allow on-farm anaerobic digestion facilities to accept up to 50% off-farm organic or 10,000 tonnes of certain off-farm materials without the need to seek an Environmental Compliance Approval.

There have also been various provincial and federal funding programs during this period.

The combination of these policies and programs successfully drove significant investments into Ontario's biogas sector over the last decade.

2.3 ESTABLISHING A BASELINE FOR ONTARIO: FACILITIES

At the beginning of 2019, Ontario had over a hundred operational biogas facilities (see Figures 4 and 5) which includes:

- 34 on-farm anaerobic digestion facilities, which process agricultural wastes, residuals, and manure, and also accept off-farm organics wastes.
- 8 industrial anaerobic digestion facilities, which tend to be larger than on-farm facilities and process waste and residuals from the industrial sector, and municipal source separated organics.
- 76 wastewater treatment facilities that process sewage sludge and have the potential to process other organic wastes and residuals.
- 45 Landfill gas capture systems that capture biogas from larger landfill sites.

FIGURE 4 – LOCATION OF BIOGAS OPERATIONS IN ONTARIO AS OF JANUARY 1, 2019

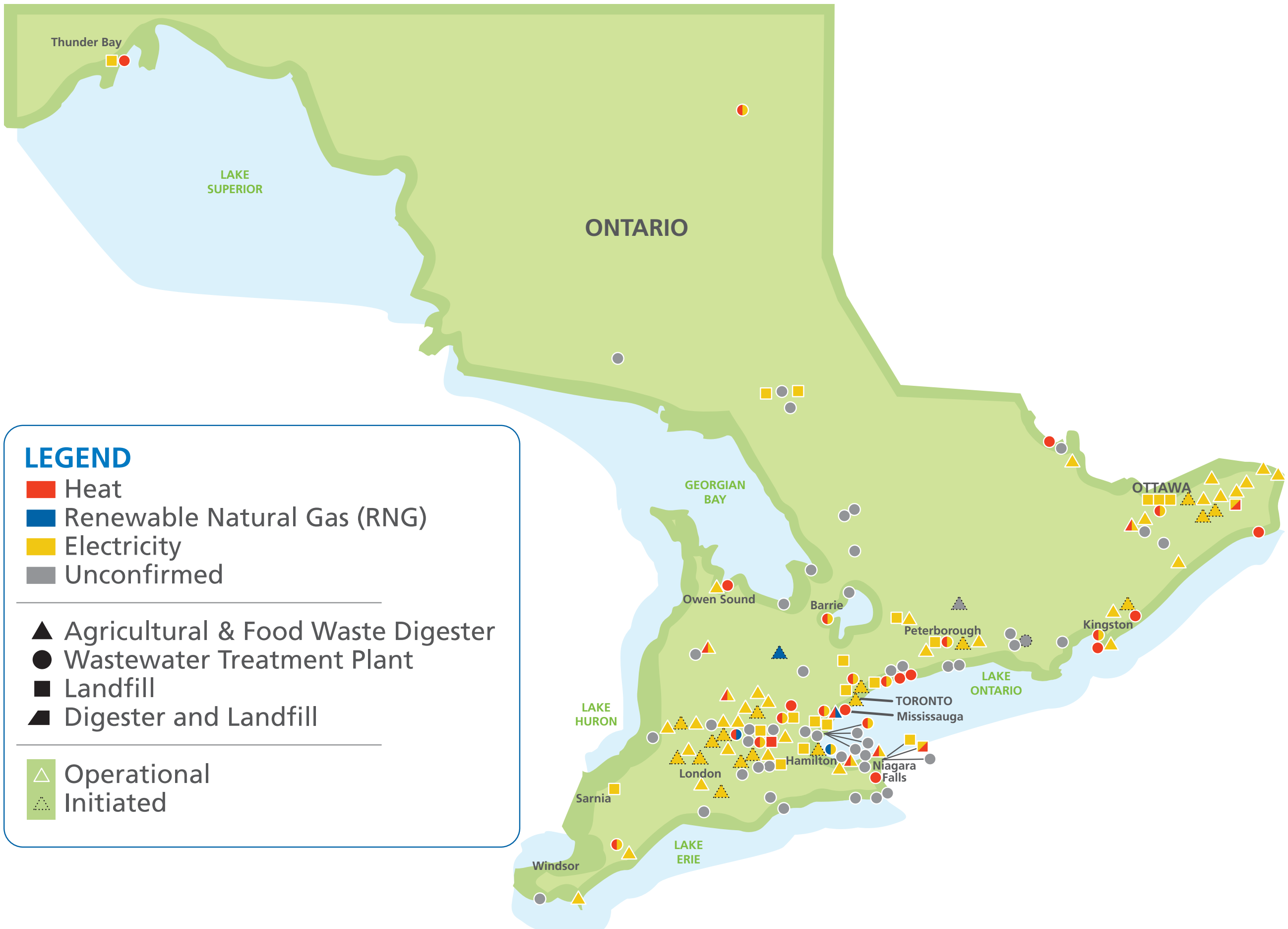
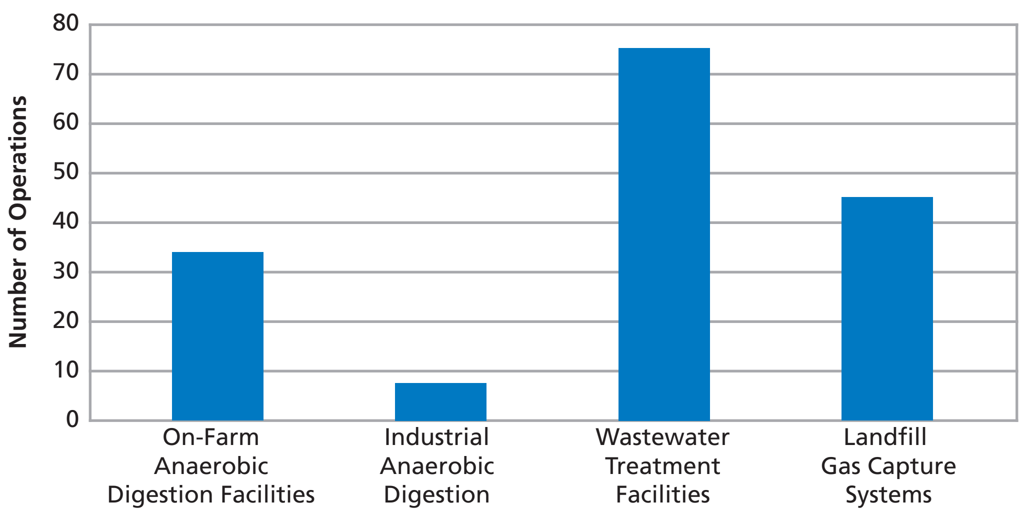


FIGURE 5 – NUMBER OF BIOGAS FACILITIES IN ONTARIO AS OF JANUARY 1, 2019[3]



[3]Note these numbers may not account for co-located facilities.

Anaerobic Digestion Facilities

The 42 operational AD facilities in Ontario have the ability to process over 600,000 tonnes of off-farm organic waste annually and over 300,000 tonnes of on-farm manures and residuals. These facilities currently process over 450,000 tonnes of organic waste per year[4] (equivalent to the weight of nearly four CN towers) and over 300,000 tonnes of on-farm manures and agricultural residuals with a contracted energy capacity of approximately 12 MW.

- ***On-Farm Anaerobic Digestion Facilities***
  Ontario currently has 34 operational on-farm AD operations. These on-farm facilities have the technical ability to process just over 200,000 tonnes of off-farm organic waste annually[5] (i.e., food processing waste) and over 300,000 tonnes of on-farm materials (i.e., manure and crop residuals).[6] Most of these facilities are operating at capacity and all generating electricity or have combined heat and power systems.
- ***Industrial Anaerobic Digestion Facilities***
  There are currently 8 operational industrial anaerobic digestion facilities in Ontario.[7] These industrial facilities have the capacity to technically process over 400,000 tonnes of organic waste.[8] Most of these facilities are operating at capacity. The focus of most of these facilities have been on generating electricity however three of these facilities are currently moving towards the generation of renewable natural gas.

These facilities help to reduce GHG emissions in the province by over 216,000 tonnes of eCO_2, equivalent to taking over 43,000 cars off the road.[9] Based on a 1 to 0.7 ratio[10] of feedstock to digestate, these facilities are producing roughly 780,000 tonnes of digestate that is returned back to the land to return nutrients and improve soil health.

There are currently 10 facilities (7 on-farm and 3 industrial), in addition to those operational facilities, in various stages of development. If built, they could increase processing capacity by 150,000 tonnes of organic waste annually. These 'initiated' facilities have an energy contract with the Provincial government or are in the midst of the approval process as of the beginning of 2019. It is important to note some projects may not materialize due to difficulty in obtaining project financing or regulatory approval. There are also several operational facilities in the process of increasing their capacity.

[4] *Ontario Waste Management Association. "State of Waste in Ontario: Organics Report," 2017. Available at https://www.owma.org/articles/state-of-waste-in-ontario-organics-report-second-annual-report.*

[5] *Ibid.*

[6] *Information from the Ontario Ministry of Agriculture, Food and Rural Affairs on May 15, 2019.*

[7] *This includes one facility that is offline and one that is in the operational start-up phase.*

[8] *Ontario Waste Management Association. "State of Waste in Ontario: Organics Report," 2017. Available at https://www.owma.org/articles/state-of-waste-in-ontario-organics-report-second-annual-report.*

[9] *Cars are estimated to emit 5 tonnes of eCO_2 and the tCO_2e/tonne diverted is 0.48.*

[10] *Data is currently not captured related to digestate generation. Every facility will have a different input to output ratio. The ratio utilized is meant to take into account some operations that dewater digestate*

Wastewater Treatment Facilities

In 2019, Ontario has 76 operational wastewater treatment facilities (of 486) that employ anaerobic digestion. The data for these facilities is still rudimentary but at least 17 of these facilities are currently utilizing biogas to generate heat, energy or a combination of the two instead of simply flaring the gas generated.[11] Generally, the biogas potential generated from biosolids alone is low and wastewater treatment facilities are typically designed based on population size. These factors can limit the amount of electricity or renewable natural gas that can be produced by wastewater facilities. However, accepting source-separated organics for co-digestion with biosolids at a wastewater facility can greatly enhance gas generation and increase opportunities for electricity or renewable natural gas generation.

There is a growing interest by municipalities in Ontario to move in this direction, allowing them to address organics processing needs using existing digester capacity. Stratford is in the process of upgrading their wastewater facility to allow for co-digestion and a 2017 report by the Environmental Commissioner of Ontario[12] discussed the value proposition, as well as, the need for the Province to simplify the regulatory approvals process for energy recovery systems associated with anaerobic digestion at wastewater treatment plants, including systems that co-digest off-site organics.

Landfill Gas Capture Systems

In 2019, Ontario had 45 landfills (of 805 operational landfills)[13] that have landfill gas collection systems in place. The economics to implement these systems are dependent on the size of the landfill, the amount of waste in place that is producing methane and the amount of waste that is disposed on an annual basis. Of the 45 landfills that currently have landfill gas collection systems in place, 23 are flaring the gas. The remaining 22 are generating energy with two of these systems providing fuel to nearby industries. There is a growing interest for those flaring the gas to either produce renewable natural gas or electricity. The barriers to date have been economic and logistical (i.e., distance to the electricity or gas grid).

At an efficiency rate between 60% to 75%[14], it is estimated that these landfills help to reduce emissions by at least 2.8 - 3.5 megatonnes tonnes of eCO_2 of the total 8 megatonnes generated by all landfills.[15,16] They have an electricity generation capacity of roughly 65 MW.

[11]Based on internal research undertaken by the Canadian Biogas Association.

[12]Environmental Commissioner of Ontario. "Every Drop Counts: Reducing the Energy and Climate Footprint of Ontario's Water Use," 2017. Available at http://docs.assets.eco.on.ca/reports/energy/2016-2017/Every-Drop-Counts.pdf.

[13]Ontario Waste Management Association. "State of Waste in Ontario: Landfill Report," 2019. Available at https://www.owma.org/articles/2019-owma-landfill-report.

[14]Note large landfills with gas collection systems can achieve rates of 85% landfill gas capture.

[15]GHD. "Cap-and-Trade Research for Ontario's Waste Management Sector," 2016.

[16]Environmental Commissioner of Ontario. "Beyond the Box: Ontario's Fresh Start on Waste Diversion and the Circular Economy," 2017.

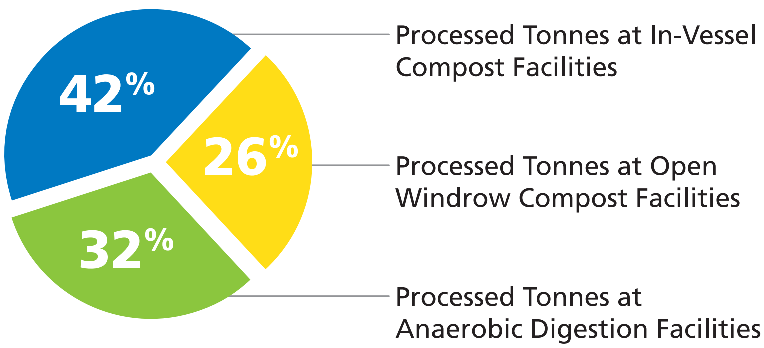
2.4 ESTABLISHING A BASELINE FOR ONTARIO: FEEDSTOCKS

Biogas facilities are reliant on access to reliable feedstocks that meet their quality needs. Key aspects of a clean feedstock include: methane yield, availability, consistency, cleanliness (e.g., lack of contamination), and ability to generate tipping fees. The following provides an assessment of current availability of feedstocks.

Residential Source Separated Organics (SSO) and Leaf and Yard Waste

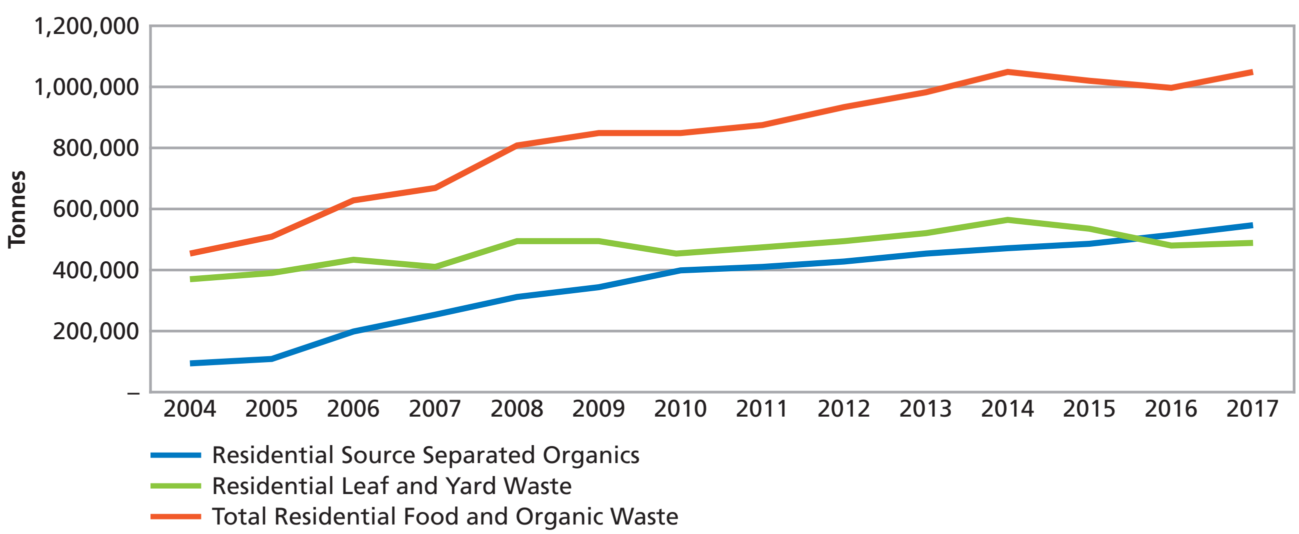
Ontario estimates that the province generates 3.7 million tonnes of food and organic waste annually which amount to 32% of overall waste generation.[17] Currently, about 1.48 million tonnes or 40% is diverted to compost facilities or anaerobic digestion facilities. Figure 6 provides breakdown of the amount of waste processed at different organic processing facilities.

FIGURE 6 – ORGANIC WASTE PROCESSED (EXCLUDES BIOSOLIDS AND ON-FARM WASTE) AT ORGANIC PROCESSING FACILITIES IN ONTARIO



The diversion rate of residential organic waste has grown significantly, over 225%, since 2004[18] and as municipal green bin programs mature there is an increasing amount of organics diverted (see Figure 7).[19]

FIGURE 7 – RESIDENTIAL FOOD AND ORGANIC WASTE PROCESSED 2004-2017



[17] *Ministry of Environment, Conservation and Parks. "Food and Organic Waste Framework," 2018.*

[18] *Residential organic diversion data available from the Resource Productivity and Recovery Authority's Municipal Datacall.*

[19] *City of Toronto. "Green Bin Organic Waste Processing and Capacity in the Province of Ontario," June 28, 2018. Notes that the City of Toronto experienced a 10% increase in green bin collection from 2016 to 2017.*

ICI Source Separated Organics

Similar data for industrial, commercial and institutional (ICI) food and organic waste is not available however it is believed that about 440,000 tonnes of a total of 1,621,500 tonnes of food organic and organic waste generated annually from these sectors is diverted to organic processing facilities.[20] Drivers for this growth include: corporate social responsibility, government policies and regulation, and economics.

Agricultural Sources

The agricultural sector can produce biogas from animal manures, crop residues and purpose grown energy crops. Currently on-farm facilities mainly process manure and crop residuals, with few currently using purpose grown energy crops. Over 300,000 tonnes of on-farm materials (e.g., manure and crop residuals)[21] is currently processed at on-farm facilities. Based on the work undertaken in the *Canadian Biogas Study: Benefits to the Economy, Environment and Energy, 2013*, this represents a fraction of the available manure and agricultural residuals.

Landfills Gas Capture

The data related to the efficiency of landfill gas capture systems and the potential for new landfill gas capture systems is also not well understood. Based on the *National Inventory Report 1990-2015*, there appears to be opportunity as Ontario produced over 7 megatonnes of CO_2e (mostly from methane) from landfills. There is also opportunity to generate energy from the 23 landfills with gas capture systems that are currently flaring gas. Many of these landfills are currently investigating opportunities to generate renewable natural gas.

Biosolids from Wastewater Treatment Facilities

The most thorough assessment to date of the potential capacity of existing anaerobic digesters at wastewater facilities to accept other organics has been done by the Southern Ontario Water Consortium (SOWC).[22] The report by the SOWC identifies substantial opportunities to increase capacity if secondary digesters were upgraded or innovative pre-treatment technologies were implemented. The report noted that capacity could increase by a total of almost 100,000 tonnes of volatile solids/year if secondary digesters were upgraded, or 110,000 tonnes volatile solids/year (approximately 30%) through deploying innovative pre-treatment technologies. This represents significant potential for processing additional organic wastes at these facilities. The report also noted that anaerobic digestion capacity is well distributed: there is at least one WWTP with an AD process in each MPAC region of the province.

Additional data and regional analysis would better quantify future opportunities.

[20] *Ministry of Environment, Conservation and Parks. "Food and Organic Waste Framework," 2018.*

[21] *Information from the Ontario Ministry of Agriculture, Food and Rural Affairs on May 15, 2019.*

[22] *Latest reports by the Southern Ontario Water Consortium are available at https://sowc.ca/boardcommittees/biosolids-working-group/.*

3.0 Ontario's Changing Landscape

The policy landscape in Ontario has changed since publishing *Renewable Natural Gas Developments in Ontario: an Evolving Outlook* in 2017. However, policy initiatives have been announced that will support biogas growth in Ontario. A summary of these proposed initiatives as they are understood to date, and how they relate to building an RNG market in Ontario are described below. The Canadian Biogas Association hosted three in-person seminars to bring awareness to these integrated topics and specifically the relevance for RNG adoption.

3.1 MADE-IN-ONTARIO ENVIRONMENT PLAN

Voluntary Renewable Natural Gas Program

To achieve the action of increasing access to clean and affordable energy for families, the *Made-in-Ontario Environment Plan* includes an initiative to implement a voluntary renewable natural gas option for customers to be administered by the natural gas utility, Enbridge Gas Inc.

Select jurisdictions in North America including British Columba, Vermont and Michigan offer voluntary RNG programs through the local natural gas utility for residential and commercial customers. The program is available to customers who choose to participate to reduce GHG emissions by purchasing RNG at a premium. Refer to CBA's *Introduction to Voluntary RNG Programs in North America* reference sheet to learn about common program elements and examples from other jurisdictions.

It is unclear yet what the degree of participation would occur in Ontario with a voluntary program. However, if all provincial government buildings were to use renewable natural gas that would be equivalent to ten AD facilities each processing 55,000 tonnes of source separated organics annually.[23] Similar steps could also be taken related to government fleets including public transit and waste collection.

Reducing Litter and Waste in Our Communities

The latest discussion paper entitled "*Reducing Litter and Waste in Our Communities*", released by Ontario's Ministry of Environment, Conservation and Parks in March 2019, re-commits to the requirements established in the *Food and Organic Waste Policy Statement*. The *Policy Statement* provides direction to entities that generate, manage or oversee food waste and organic waste (e.g., organic waste from food preparation and soiled paper), including municipalities, multi-unit residential building owners, private waste management providers, industry, commercial entities and institutions that generate larger volumes of organic waste.

The language used is aligned with *Planning Act* requirements (i.e., "Shall" = clear direction; "Should" = moderate direction; "Encourage" or "May" = minimal direction). Tables 1-3 refer to requirements related to the AD sector. For all requirements including additional details please refer to the *Food an Organic Waste Policy Statement,* which is available on the Ministry of Environment, Conservation and Park's website.

[23] *Based on the Ontario government 2015 Energy consumption and greenhouse gas emission report available at https://www.ontario.ca/page/2015-energy-consumption-and-greenhouse-gas-emission-report. The government uses the 355,024,880 equivalent kilowatt hours of natural gas a year in government buildings (236,683,253*1.5). That is equivalent to 31.9 million cubic metres of natural gas based on the following conversion – https://www.businessenergy.com/business-gas/gas-bill-calculator/.*

TABLE 1 – MUNICIPAL REQUIREMENTS RELATED TO DIVERSION

	Southern Ontario			Northern Ontario
	Municipalities with Green Bin programs	Higher density municipalities[2]	Large & medium municipalities with medium density[3]	Large municipalities with higher density[4]
Shall	• 70% target by 2023 • Maintain or expand curbside services • Areas without curbside provide other diversion opportunities	• 70% target by 2025 • Provide curbside in urban settlement areas to single family homes • Areas without curbside provide other diversion opportunities	• 50% target by 2025 • Provide curbside in urban settlement areas to single family homes • Areas without curbside provide other diversion opportunities	
	• Ensure official plans consistent by period determined in the *Planning Act* • Ensure bylaws amended within 3 years after official plan update • Work with municipal associations on promotion and education to promote recovery • Ensure approvals for new or expanded resource recovery facilities address *D-Series Land Use Compatibility Guidelines* and the *Compost Guideline*			
Should	• Pursue regional options to facilitate collection • Ensure official plans, zoning by-laws, plan or subdivision approvals and site plan approvals support resource recovery of food and organic waste • Protect existing/planned resource recovery systems from incompatible uses, where appropriate, to meet projected needs • Co-ordinate with the province and other planning authorities to facilitate timely decisions for resource recovery systems • Consider how existing policies and procedures could encourage the use of compost, digestate and other soil amendments			
Encourage/ May	• Accept other materials such as personal hygiene, sanitary products, shredded paper, additional paper fibre products, compostable products and packaging and pet food and wastes • Establish performance metrics to monitor implementation of policies • Plan for the management and beneficial use of biosolids • Consider use of wastewater treatment infrastructure • Pursue regional approaches to address processing needs • Support technology and innovation to recover compostable products and packaging			

TABLE 2 – DIVERSION REQUIREMENTS FOR MULTI-UNIT RESIDENTIAL BUILDINGS, COMMERCIAL AND INSTITUTIONAL BUILDINGS THAT MIGHT BE OWNED OR SERVICED BY MUNICIPALITIES

	Multi-residential buildings with 6 or more units	All commercial buildings subject to O.Reg 103/94 that generate more than 300/kg week	All commercial buildings not subject to O.Reg 103/94 that generate more than 300/kg week	All commercial buildings subject to O.Reg 103/94 that generate less than 300/kg week	Educational institutions and hospitals subject to O. Reg 103/94 that generate more than 150 kg
Shall	• 50% target by 2025	• 70% target by 2025	• 50% target by 2025	• 50% target by 2025	• 70% target by 2025
	• Source separation or equivalent				

TABLE 3 – REQUIREMENTS OF SERVICE PROVIDERS

	All Food and Organic Waste Service Providers
Shall	• Minimize contamination • Use appropriate technologies • Not direct source separated materials to disposal
Should	• Provide complete submissions for necessary approvals • Develop community outreach plans • Ensure mixed waste facilities only accept source separated organics where contamination or processing availability issues arise • Ensure mixed waste facilities demonstrate regularly that outputs meet applicable environmental quality standards. • Ensure mixed waste facilities send materials for further processing where necessary • Promote and educate on the use and benefits of compost, digestate and other high-quality soil amendments • Make compost convenient and accessible • Increase the beneficial use to build soils
Encourage/ May	• Adopt financial measures to encourage generators to maximize resource recovery and discourage disposal • Reduce GHG emissions from operations and manage as close to source as possible • Maximize energy recovery to reduce GHG emissions

Based on targets established in the Food and Organic Waste Policy there are a number of municipalities that will be required to implement new organics programs and meet targets by 2025. This includes the following Ontario municipalities:

- London
- Essex-Windsor
- Brantford
- City of Peterborough
- Sarnia
- Chatham-Kent
- Kawartha Lakes
- Norfolk County
- Cornwall
- Woodstock
- Stratford
- Brockville
- Owen Sound
- Cobourg
- Thunder Bay
- Sault Ste Marie

If each of these municipalities were to collect 120kg to 150kg per household,[24] it would mean an additional 86,500 to 105,000 tonnes of residential source separated organics that will need processing by 2025. For those municipalities already operating green bin programs, if these programs increase collection by 2.5% per year due to population increases, increased diversion from multi-unit residential and program maturity, it will increase the amount of residential source separated organics by over 200,000 tonnes that will need processing by 2025.

Given the lack of robust data related to the ICI sector, it is difficult to predict the impacts related to the targets in the Food and Organic Waste Policy Statement. If the diversion rate doubles based on current diversion rates, there would be an increase in the amount of ICI sector source separated organics collected by 418,000 tonnes.

Table 4 provides a breakdown of the additional tonnes of source separated organics that would be collected and require processing.

TABLE 4 – PROJECTED INCREASE IN SOURCE SEPARATION BASED ON REQUIREMENTS IN THE FOOD AND ORGANIC WASTE POLICY STATEMENT – 2017-2025

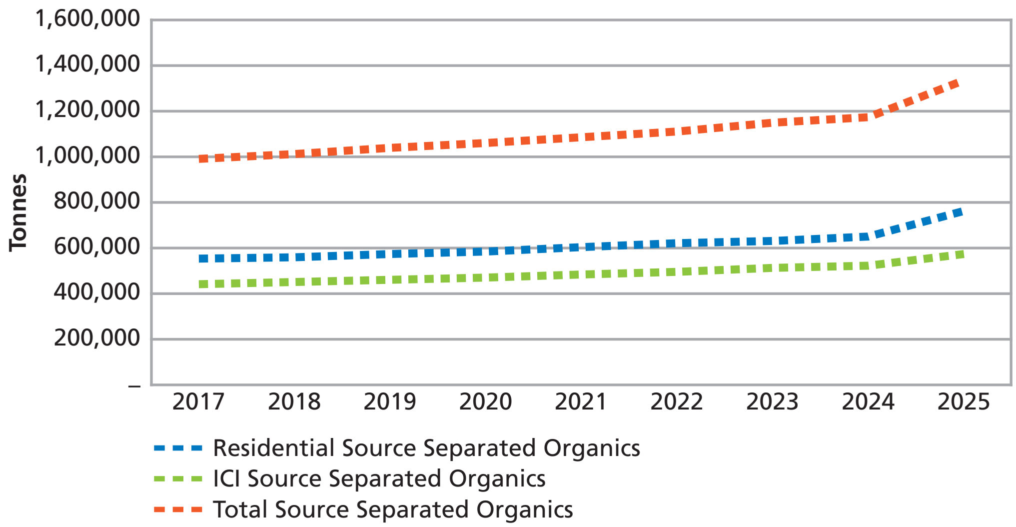
Requirements in Food & Organic Waste Policy Statement	Amount of Additional Tonnes of SSO Captured by 2025	Current Performance[25]
Municipalities without Green Bin Programs	95,500	0
Improvements in capture rates of current Green Bin programs	106,000	546,000
Industrial, Commercial and Institutional Sectors	418,000	400,000
Total	619,500	946,000

Figure 8 provides a projection related to an incremental increase in the amount of source separated organics (i.e., does not include leaf and yard waste) related to the targets in the *Food and Organic Waste Policy Statement*.

[24] *Based on 2017 RPRA Datacall for household organic waste.*

[25] *Based on data from Ontario's Food and Organic Waste Framework (https://www.ontario.ca/page/food-and-organic-waste-framework) and 2017 RPRA Datacall for household organic waste.*

FIGURE 8 – PROJECTED INCREASE IN SOURCE SEPARATION BASED ON REQUIREMENTS IN THE FOOD AND ORGANIC WASTE POLICY STATEMENT – 2017-2025



Given most compost and AD facilities are at or close to their maximum processing capacity, approximately 600,000 tonnes of additional capacity will be necessary to meet future demands. If all of this demand was met through AD facilities, it would mean a doubling of Ontario's current capacity over the next six years.

The Province is also still considering the development of a proposal to ban food waste from landfills as part of its most recent discussion paper. Depending on the timelines this could significantly increase the amount of available feedstocks for AD facilities.

Based on the potential increased diversion of food and organic waste, Ontario has the potential to triple the amount of organic waste processed through AD facilities to 1,350,000 tonnes and reduce GHG emissions by 648,000 tonnes of eCO_2, equivalent to taking over 129,000 cars off the road.

3.2 CLEAN FUEL STANDARD

Similar to Ontario, the federal government is investigating a means to transition Canada to a low carbon economy. A Clean Fuels Standard (CFS) is in development to target a 30 Mt GHG reduction nationally by 2030. The goals of the CFS are:

- to reduce the carbon footprint of fuels supplied in Canada;
- to promote the use of clean technology, lower carbon fuels, and promote alternatives such as biogas; and,
- to apply a performance-based approach using life-cycle analysis.

The CFS is expected to take into account a broad coverage of fuels including liquid, gaseous and solid fuels used within industry, transportation and buildings.

As the CFS develops, consideration is needed with how federal and provincial policies will work together to create strong, supportive mechanisms that respect the regional variation in economic profiles, energy sectors, emission profiles, and trade activities.

4.0 Steps to Success

Policies in development at the provincial and national level could help to support the development of RNG projects and establish an RNG market in Ontario. The Canadian Biogas Association convened three *Biogas Think Tank* sessions of industry stakeholders in 2018 and 2019. The objective of these sessions was to discuss incoming policies and the challenges and opportunities it presents for RNG project implementation. During these discussions that helped with the creation of this report, participants identified the following broad actions to support broader biogas/RNG development:

- **Support investment and infrastructure to better collect and divert organic waste**
  The biogas sector understands the importance of proper stable regulation to guide the development and operations of biogas and RNG projects in Ontario. The existing regulatory framework however poses many unnecessary burdens related to developing projects that involve excessive time commitments and expending large amounts of government resources on activities that do not bear value. There are opportunities for improvements in how resources are used to achieve results much more effectively and efficiently without hindering important new investments.

  Necessary changes include:

  - *Modernize environmental approvals:* Cutting regulatory red tape and modernizing environmental approvals are essential to support sustainable end markets for waste and new waste processing infrastructure. The Environmental Activity and Sector Registry (EASR) provides a means to address many low risk activities in the biogas and RNG sector. Temporary regulatory exemptions or simplified approval process for demonstration and pilot projects would also be helpful
  - *Re-evaluate On-Farm Anaerobic Digestion Facility Allowances:* It has been over five years since changes were made to allow on-farm anaerobic digestion facilities to accept up to 50% or 10,000 m^3/year of certain off-farm organic waste materials (O. Reg 267/03). In December 2018, the CBA engaged with Ontario Ministry of Agriculture Food and Rural Affairs to discuss possible improvements to the Nutrient Management Regulation specifically related to increasing the limit of off-farm material to 20,000 m^3/year. Existing facilities have been well run and offer substantial opportunities to diversify farm revenue and return nutrients directly back to the land.
  - *Improve Land Use Planning:* There is a need to improve coordination of land use planning and environmental approval processes by updating ministry guidelines (i.e., the D-Series Guideline) to help municipalities avoid the impacts of conflicting land uses. To support resource recovery, creating and protecting land with suitable land use planning designation and zoning are critical. This should include flooding, stormwater management, and other climate impacts and measures that would minimize or prevent disasters and insurance claims in the province. This can also include land use changes to facilitate industrial developments in areas that could provide microgrids or district heating for communities.

- o *New Approach to Financial Assurance:* The current Financial Assurance approach in Ontario ties up substantial amounts of capital (i.e., $200 million) and unnecessarily hinders investment and infrastructure growth in Ontario. The CBA recommends amending the current Financial Assurance Guideline to adopt a pooled financial assurance model for biogas facility operators. This approach unlocks this stranded capital and would allow the private sector to more readily invest in the ongoing resilience of the sector. A pooled financial assurance model may allow for a blend of instruments such as insurance.

- **Encourage value creation**

For the biogas sector, we have the ability to not only capture energy and reduce greenhouse gas emissions, but also create a nutrient rich product can help address the many issues across the province related to poor soil health. Previous governments have often too narrowly focused on diversion from disposal and failed to link the economic opportunity.

The following are ways that the government can better harness the economic opportunities associated with encouraging value creation:

- o *RNG Pipeline Injection:* RNG is a versatile fuel with multiple opportunities for utilization, however, there are unfortunately no RNG programs in Ontario at this time. Ontario-based RNG projects are therefore actively seeking markets outside of the province to support their development. Requiring the natural gas utilities in Ontario to implement a voluntary RNG option for customers and consult on the appropriateness of a complementary clean content requirement is a positive first step. Further, a policy statement which solidifies RNG end-markets would also be helpful by providing for long-term offtake contracts and escalating procurement requirements placed on the regulated natural gas utilities (e.g., increasing blend rates of 0.1%, 0.5%, and 1.0% RNG by 2020, 2025 and 2029, respectively).
- o *RNG for transportation:* Remove barriers for expanding 24/7 compressed natural gas (CNG) refueling stations for trucks along the 400-series highways and provide government support for the conversion of heavy-duty truck fleets that return to base every night such as solid waste collection vehicles, school buses etc. into CNG/RNG.
- o *Green Procurement Policies:* Bolstering green procurement practices has the potential to position the government as a leader in the adoption of new technologies as well as goods and services in this area. This could include government procurement of RNG for use in government buildings and/or fleets and the use of digestate for roads, site remediation projects, and other provincial infrastructure construction.
- o *Tax Credits for Replenishing Agricultural Lands:* Address transportation related barriers associated with digestate management by creating a tax credit for farmers to transport products from organic waste processing facilities (ie. digestate, compost, biosolids) for use on their land.

- **Implement the Food and Organic Waste Policy Statement and food and organic waste disposal ban**

  The need for a consistent supply of feedstocks is compromised by the availability of cheap landfill capacity that does not take into account externalities. The Food and Organic Waste Policy Statement and the potential implementation of a food and organic waste ban ensure necessary feedstocks. The Province should consider the following:

  - *Ensure proper oversight and enforcement:* The CBA recommends Ontario allocate proper resources for oversight and enforcement. Many jurisdictions often do not allocate appropriate resources to ensure proper oversight and enforcement or create regulations that are difficult to enforce (i.e., O. Reg. 103/94). Given the role that the Resource Productivity and Recovery Authority is already playing, it may make sense for them to help play an oversight and enforcement role related to the Food and Organic Waste Policy Statement. This role should also include better collection and publication of data.
  - *Establish a date of implementation and a clarify what a food and organic waste ban means:* Typically, food and organic waste bans are implemented over a 5 to 10-year time period to allow time for appropriate steps to reduce waste, implement programs, and develop infrastructure. The implementation of the disposal ban is a complementary next step to the Food and Organic Waste Policy Statement. The Province should establish a date of implementation of a full disposal ban.

5.0 Vision

In the next 10 years, the Canadian Biogas Association's vision is to grow the sector in the following five ways (see Figure 9):

1. Enable all landfills with existing gas capture systems to generate electricity, fuel or renewable natural gas.

Currently only about half of Ontario's landfills that have landfill gas capture systems in place are producing energy. The other half are simply flaring gas. Implementing Clean Fuel Standards as well as increasing the demand for renewable natural gas should enable opportunities for all of these facilities to generate greater value from the gas they are already capturing.

2. Double the value of soil amendments and become a staple for all cash crop farmers in Ontario

The value of soil amendments has been growing in Ontario but in many cases, it is provided to the agricultural sector at no cost. There is substantial opportunity for the sector to increase the value of these products over the next decade to compete with other nutrient based amendments. As noted in Ontario's Agricultural Soil Health and Conservation Strategy, there is growing concern about the degradation of Ontario's soil health and what it could mean for cash crop farmers.

3. Triple the capital investments related to the biogas sector and the amount of food and organic waste processed at AD facilities

Given the food and organic waste processing demands related to Ontario's Food and Organic Waste Policy Statement and a proposed disposal ban, there is substantial opportunity to increase the capital investment in the biogas sector specifically related to new or expanded anaerobic digestion facilities or in retrofits to wastewater facilities to allow for co-digestion.

4. Increase energy production by five times current levels

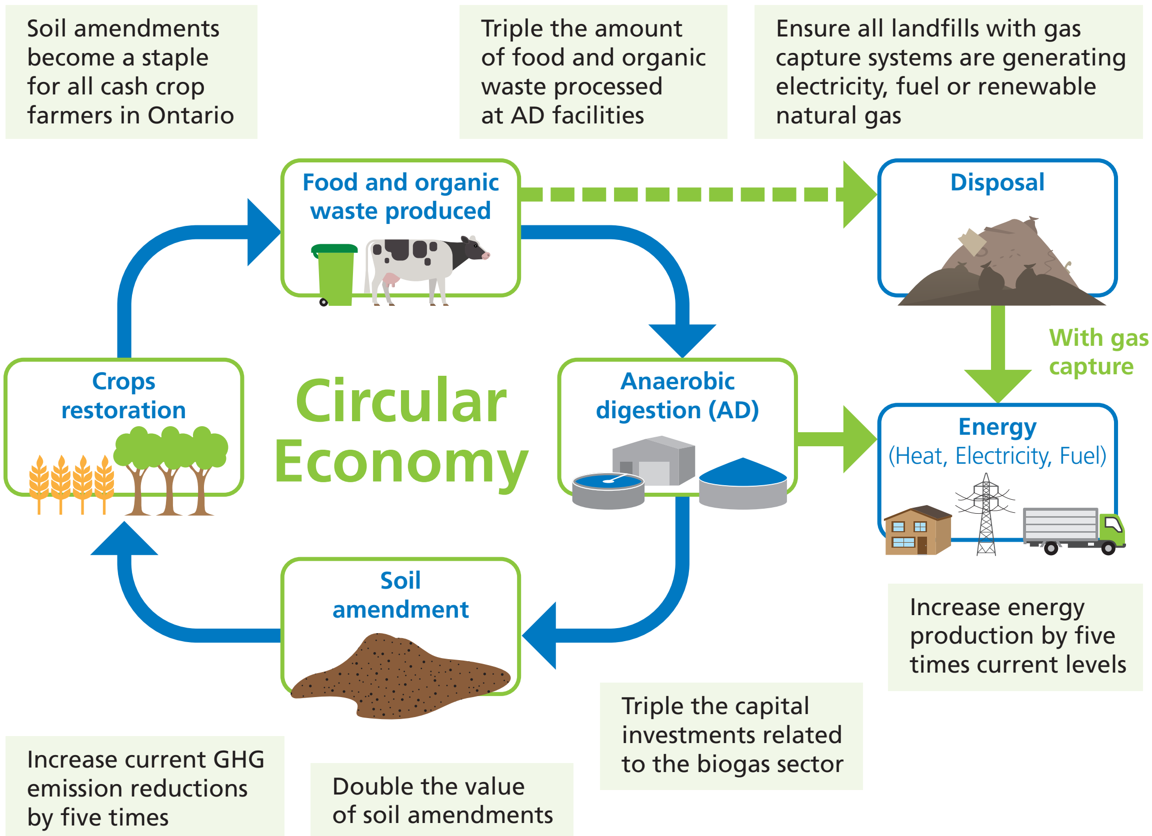
By opening up energy markets beyond electricity to fuels and renewable natural gas there is a substantial opportunity to increase energy production from current and new anaerobic digestion facilities, wastewater treatment facilities and landfills.

5. Increase current GHG emission reductions by five times

By reducing the amount of methane being released from organic waste in landfills and through the generation of renewable energy, Ontario could play a significant role in helping to reduce greenhouse gases in Ontario and meet its current targets.

This vision includes growth in all types of biogas facilities from on-farm and industrial AD facilities to wastewater facilities and landfills gas capture systems.

FIGURE 9 – VISION FOR THE BIOGAS ASSOCIATION IN ONTARIO



Canadian Biogas Association

275 Slater Street, Suite 900, Ottawa, Ontario, K1P 5H9, Canada

www.biogasassociation.ca

ENBRIDGE GAS INC.

Undertaking Response to Anwaatin

To advise of what Enbridge Gas plans to purchase: molecule plus environmental attributes, just environmental attributes, or [no] molecule that has had its environmental attributes separated out.

Response:

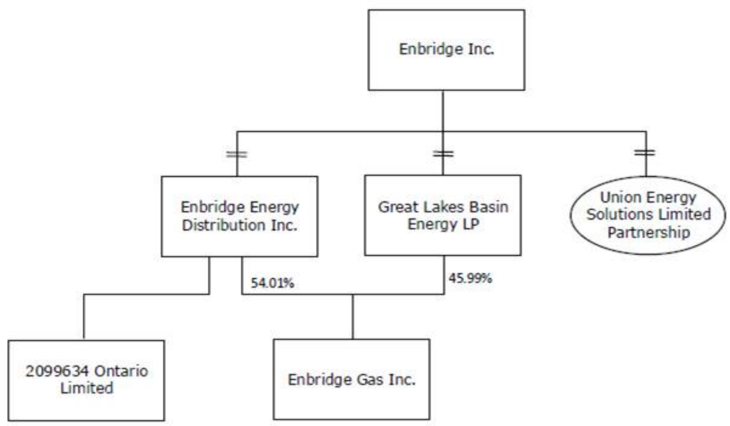
For the purpose of the Company's Voluntary RNG program as proposed in this application, at this time it is the Company's intention to acquire supplies of RNG that include only the molecule and the environmental attribute related to the substitution value of RNG.

ENBRIDGE GAS INC.

Undertaking Response to SEC

To provide a chart showing the corporate structure of EGI Inc. including the affiliates referred to in SEC 3

Response:



Ownership is 100% unless otherwise noted

ENBRIDGE GAS INC.

Undertaking Response to IGUA

To provide the presentation to senior management explaining the proposal and its objectives.

Response:

Please find attached a presentation made to Enbridge Gas senior management in August of 2019 regarding the Program. Subsequent to delivery of this presentation, some details of the Program were revised, with such revisions incorporated into the final application and supporting evidence filed in this proceeding.

Voluntary Renewable Natural Gas Program

ENBRIDGE®

Business Development
August 2019

Agenda

- Background
- Drivers
- Objective
- Proposed Program
- Engagement
- Approvals and Next Steps

Background

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- As part of its 2018 Cap and Trade Compliance Plan, Enbridge Gas made plans to purchase renewable natural gas (“RNG”) as an emission reduction activity; subject to the receipt of government funding
- The new Ontario Government’s cancelation of the Cap and Trade program eliminated RNG funding opportunities; therefore suspending Enbridge’s plans to purchase RNG
- In Fall 2018, the Ontario Government released the new Made-in-Ontario Environment Plan, which outlines a requirement for natural gas utilities to implement a voluntary RNG option to customers
  - *“Require natural gas utilities to implement a voluntary renewable natural gas option for customers. We will also consult on the appropriateness of clean content requirements in this space.”*
- The Ontario Government has no interest in supporting a voluntary RNG program that would impact rate payers not participating in the program

Drivers

Policy
- Supports the government's emission reduction efforts while leveraging Enbridge's existing assets
- Aligns with the upcoming Federal Clean Fuel Standard
- Supports the Made-in-Ontario Plan

Growth
- Enables RNG market growth in Ontario
- Utilizes Enbridge's existing infrastructure and expertise in delivering reliable and cost-effective supply

Low Risk
- Not dependent on government funding or mandatory rate-payer subsidies
- Insulated from carbon pricing political and policy uncertainty
- Over half of Enbridge's customers support a form of voluntary RNG program

Strategic Alignment

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Utilities and Power Operations Strategy on a Page

Ambition

Be the Energy Utility and Sustainable Energy Provider of Choice

Measures of Success

- Continue to achieve best in class safety and operational reliability in Utilities and Power Operations
- Consistently earn above OEB allowed ROE while integrating the legacy utilities
- Generate growth by investing over $1B per year in infrastructure renewal, growth and low risk lower carbon initiatives
- Achieve or maintain top 3 box scores of at least 75% for the following touchpoints: contact centre, online account management tools, service visits and attachments.

Strategic Imperatives and "growth horizons"

Optimize Base Business	Execute on Growth Projects	Grow the Business
Achieve operational excellence in safety, reliability and cost performance	Deliver near-term in-franchise rate base growth; customer additions, community expansion, storage and sustainable energy projects	Expand our footprint in complementary lower-carbon and energy-efficient solutions
Increase value of existing assets		Secure future in-franchise growth and expand to new communities
Build best in class operating model, capture synergies from integration and build for the future		Expand Dawn Hub storage and transmission

Understand and exceed customer expectations to be *the* trusted energy provider

"How to win" (Sources of competitive advantage)

- Apply effective decision making and utilize efficient processes
- Maintain superior know-how to develop opportunities with the right risk/return profile
- Continue to adopt new technologies to improve business performance and customer experience
- Continue to foster and grow strategic partnerships with regulators, governments and industry stakeholders
- Leverage risk based approach to safety and operational reliability
- Utilize transformation experience to achieve synergies and develop new business opportunities
- Leverage the scale of the amalgamated organization to realize cost leadership and shape industry direction
- Harness scale of customer connections to inform development of products and services that fit customers' needs and wants
- Leverage storage and transportation assets at Dawn

Critical Enablers (What we need)

- Investments in operating infrastructure and technology
- Clear organizational structure, accountabilities and governance
- Attraction, retention and development of highly capable people
- Building and maintenance of stakeholders and decision makers' confidence
- A competitive mindset
- Financial discipline and understanding of regulated environment by all levels

Program Objective

Introduce a Voluntary RNG Program

Proposed Program

A fixed monthly charge with no % RNG content considerations

- Offer residential customers the option to pay a $2/month premium on their natural gas bill in exchange for RNG content in Enbridge's supply
  - RNG content will not be defined
  - Participating customers will have a minimum of one year commitment
  - Participating customer will receive annual reporting with GHG benefits and volumes
- Non-participating customers will have no rate impacts
- Enbridge will use RNG participation revenues to cover both administration and RNG procurement costs
- Enbridge will procure RNG using short-term or spot supply contracts

Proposed Program

Design Considerations

Billing System Capabilities:

- Legacy systems are unable to charge customer consumption at two different rates
- Integration efforts for legacy systems do not support significant system changes
- Set recurring flat monthly charges can be accommodated

Customer Response:

- 2% of surveyed customers are willing to pay $2/month for RNG content; with no % blend considerations

Implementation:

- Simple approach to allow the introduction of an RNG program without the need for policy or regulatory changes
- No risk to Enbridge or rate payers as program costs will be covered by participating customers

Key Program Elements

First Five Years…

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~25,000 participants

~15,000 GJ/Year

~4,000 tCO2e GHG emission reduction

~0.5 MM capital costs

*Note: 0.5 M capital costs does not include annual O&M costs of 0.2M/year

Proposed Program

Participation Estimates

Program Year	1	2	3	4	5	6	7	8	9	10	Total
Estimated Customer Participation (%)	0.6%	0.7%	0.7%	0.8%	0.8%	0.9%	0.9%	1.0%	1.0%	1.1%	
Estimated Customer Participation (#)	21,087	22,844	24,602	26,359	28,116	29,873	31,631	33,388	35,145	36,902	
RNG $ Collected From Participants	$ 506,090	$ 548,264	$ 590,438	$ 632,613	$ 674,787	$ 716,961	$ 759,135	$ 801,309	$ 843,483	$ 885,658	$ 6,958,738
Total Admin Costs	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ 200,000	$ 200,000	$ 200,000	$ 200,000	$ 200,000	$ 2,500,000
Capital Cost Recovery	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ -	$ -	$ -	$ -	$ -	$ 500,000
Annual O&M Costs	$ 200,000	$ 200,000	$ 200,000	$ 200,000	$ 200,000	$ 200,000	$ 200,000	$ 200,000	$ 200,000	$ 200,000	$ 2,000,000
Remaining RNG $ (Net of Admin Costs)	$ 206,090	$ 248,264	$ 290,438	$ 332,613	$ 374,787	$ 516,961	$ 559,135	$ 601,309	$ 643,483	$ 685,658	$ 4,458,738
Potential RNG Purchases Using Remaining RNG $ (GJ)	9,814	11,822	13,830	15,839	17,847	24,617	26,625	28,634	30,642	32,650	212,321
Potential RNG Purchases Using Remaining RNG $ (m3)	263,530	317,459	371,388	425,316	479,245	661,045	714,974	768,903	822,831	876,760	5,701,452
RNG Purchases as % of Total Sendout	0.001%	0.001%	0.002%	0.002%	0.002%	0.003%	0.003%	0.003%	0.003%	0.004%	

Engagement & Feedback

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Stakeholder Group	Ask	Contacts
Government Relations	• Seek support for a voluntary RNG program that will not require additional funding, rate payer subsidy or policy changes	Brad Lattanzi
Regulatory	• Provide input on proposed program design • Inform OEB of proposed approach	Mark Kitchen, Vanessa Innis
Legal	• Provide feedback and identify potential issues	Tania Persad
Customer Care	• Provide input on proposed program design • Identify billing system requirements to accommodate proposed program • Provide suggestions and ideas on the best way to move forward with minimum impacts on integration efforts	Darren McIlwrath, Paula Ceccacci, Victoria Wang
Gas Supply	• Provide input on proposed design • Clarify gas supply planning timelines and identify requirements (reporting, contracting, regulatory, etc.)	Jamie LeBlanc, Nicole Brunner, Erin Liberty
Rates	• Provide input on proposed program • Identify Rates filing impacts and timelines	Amy Mikhaila, Anton Kacicnik
Finance	• Provide input on program design and potential billing system changes • Identify accounting and reporting requirements • Identify required system changes to accommodate program	Ryan Small, Jennifer Broeders, Rachel Goodreau
Marketing	• Provide input on implementation strategy and customer engagement	Cara-Lynne Wade, Michelle Loleski
Business Development	• Lead program development and launch • Provide insights on available RNG supply and procurement options • Support all groups as required	Steve McGill, Fiona Oliver-Glasford, Abbas Chagani

Approvals and Next Steps

Approval

1. Approve proposed model
2. Approve $500,000 for billing modifications

Next steps

1. Socialize recommended model with key groups and seek initial feedback (Regulatory, Billing, Legal, Gas Supply, etc.)
2. Seek support from government and key stakeholder groups and industry associations (Biogas Association, MaRS, etc.)
3. Finalize program design and form a project team
4. Kick off program development and create a project timeline

Discussion

ENBRIDGE GAS INC.

Undertaking Response to IGUA

To advise whether or not value could be created from renewable natural gas through the following U.S. programs: the existing California cap and trade program, the U.S. EPA Renewable Fuel Standard, the Natural Gas Home Star programs, and the Methane Challenge.

Response:

Enbridge Gas confirms that value can be created from RNG through the California Cap and Trade Program and the United States Renewable Fuel Standard.

Enbridge Gas has reviewed the United States Environmental Protection Agency's ("US EPA") voluntary methane reduction programs (Natural Gas Star Program and the Methane Challenge) for the oil and gas sector and has not identified any method of generating value for RNG.

Enbridge Gas was not able to find any information related to a "Natural Gas Home Star" program.

ENBRIDGE GAS INC.

Undertaking Response to SEC

To inform parties of whether there are collateral benefits to Enbridge companies that are anticipated or known as a result of this application.

Response:

To the best of the Company's knowledge, the collateral benefits to Enbridge companies are noted below.

As approved by the Board in EB-2017-0319, Enbridge Gas provides RNG injection services on a regulated basis under Rate 401, as well as RNG upgrading services as a non-utility activity. The Company also makes Rate M13 available to RNG producers in the Union South rate zone, and has two unregulated affiliates that engage in RNG business activities.

The Company acknowledges that the Program might result in collateral benefits to Enbridge companies through increased use of RNG services by RNG producers. However, given the modest scale of the Program any benefits received will also be modest.

Enbridge Gas will procure RNG under the same Gas Procurement Policies and Practices used to govern the purchase of traditional natural gas and will also adhere to the requirements of the OEB's Affiliate Relationship Code for Gas Utilities. This will ensure that ratepayers and program participants are not adversely impacted in the event that Enbridge Gas procures RNG from an Enbridge-related entity.

Assuming that the Program is successful, information about the Program may be communicated by the Company and Enbridge Inc. as an example, amongst other things, of Enbridge's participation in a broader transition to lower carbon energy sources. If so, it is possible that Enbridge companies may also experience intangible benefits as a result of the Program such as reputational or public relations benefits.

ENBRIDGE GAS INC.

Undertaking Response to Anwaatin

To provide the minimum credit requirements for RNG procurement transactions, specifically whether the form of alternate credit supply would be in the form of a line of credit, or a deposit, or what percentage of the transaction value would be required.

Response:

Enbridge Gas's credit requirements for gas purchase transactions (including the purchase of RNG) are outlined in Section 4 of Enbridge Gas' Gas Supply Procurement Policies and Practices. Specifically, the amount of credit required is based on the financial risk to Enbridge Gas if the contracted supply had to be replaced due to counterparty default. Therefore, the minimum value of credit required depends on the term of the transaction and the relative risk of market price fluctuations over the term.

For example, a transaction to procure an amount of RNG for delivery in the same day is unlikely to require any credit support as there is little or no risk that the market price of RNG will increase such that Enbridge Gas needs to pay a higher amount to replace the supply as a result of the counterparty's default. Transactions with longer terms will generally require more credit.

As outlined in the Gas Supply Procurement Policies and Procedures, Enbridge Gas performs counterparty assessments following industry best practices and considers information such as public rating agency information, counterparty financial information, and any other quantitative or qualitative information that may be available. If appropriate, unsecured credit limits are established to cover transaction risk. In cases where a sufficient unsecured credit limit cannot be established, credit support is requested. Credit support is often in the form of a Letter of Credit, deposit, or, where appropriate, Parental Guarantee.

ENBRIDGE GAS INC.

Undertaking Response to LPMA

With reference to Exhibit I.STAFF.7, to provide an example that would show the situation where the dollar values of the amounts transferred out of the PGVA and into the balance sheet RNG account would be different and explain, in writing, why they are different.

Response:

The monthly adjustment to remove the incremental cost of RNG purchased from the Union South PGVA will always be equal to the dollar amount transferred to the balance sheet account used to track funds collected from the Voluntary RNG Program.

An illustrative example of the accounting entries is provided below:

In April 2021, Enbridge Gas receives 150 GJ of RNG at a price of $21.00 per GJ. The average cost of Union South delivered Dawn supply in April 2021 is $2.50 per GJ. The Dawn Reference Price as approved in the April 2021 QRAM is $2.25 per GJ.

April 2021 entry to recognize the actual purchase cost of RNG procured:

Debit: Union South PGVA (Account No. 179-106)

($21.00 – $2.25) x 150 = $2,812.50

Debit: Gas in Storage

$2.25 x 150 = $337.50

Credit: Cash/Accounts Payable

$2,812.50 + $337.50 = $3,150.00

April 2021 entry to remove incremental cost of RNG from Union South PGVA:

Debit: Voluntary RNG Program balance sheet account

($21.00 - $2.50) x 150 = $2,775.00

Credit: Union South PGVA (Account No. 179-106)

$2,775.00

As illustrated above, the net impact to the Union South PGVA is a debit of $37.50, which is equal to what the entry to the PGVA would have been had Enbridge Gas not purchased RNG and instead purchased the supply at Dawn (($2.50 - $2.25) x 150 = $37.50).

ENBRIDGE GAS INC.

Undertaking Response to LPMA

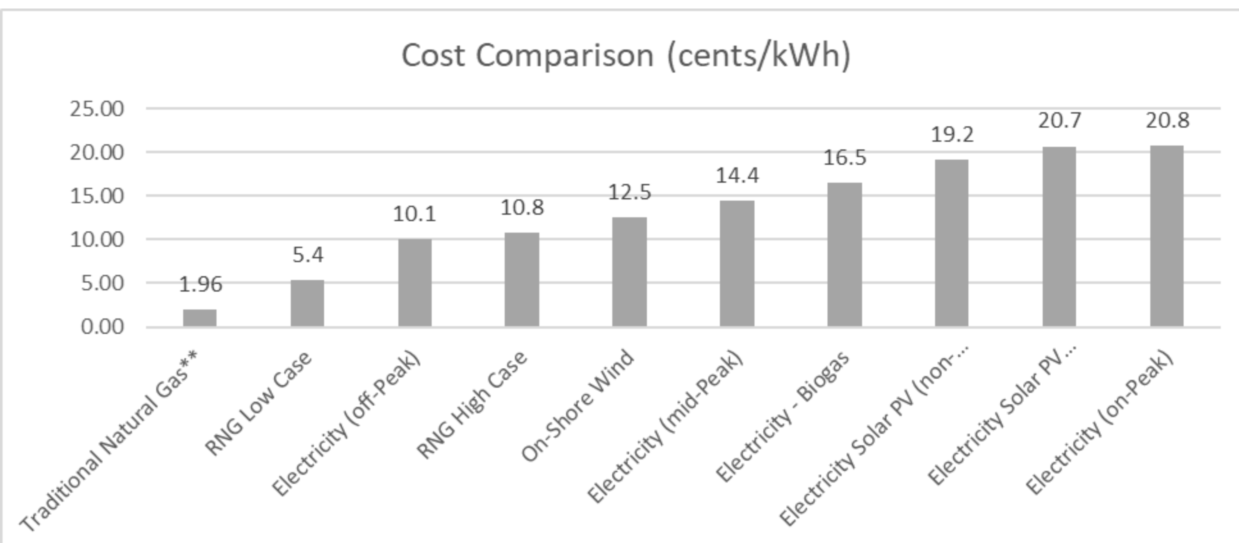
To update the 1.2 cents to reflect the carbon charge.

Response:

Energy Source*	cents/kWh	$/GJ
Traditional Natural Gas**	1.96	5.44
RNG Low Case	5.4	15.00
Electricity (off-Peak)	10.1	28.06
RNG High Case	10.8	30.00
On-Shore Wind	12.5	34.72
Electricity (mid-Peak)	14.4	40.00
Electricity - Biogas	16.5	45.83
Electricity Solar PV (non-rooftop)	19.2	53.33
Electricity Solar PV (Rooftop)	20.7	57.50
Electricity (on-Peak)	20.8	57.78

*Electricity prices as of Nov 2019 & FIT/microFIT Price Schedule Jan2017

**Updated to include Federal Carbon Charge



ENBRIDGE GAS INC.

Undertaking Response to IGUA

To explain concerns regarding allocating the reduction to the Federal Carbon Charge to the volumes in Enbridge Gas's facilities account, rather than the customer-related account.

Response:

The Company, from an administrative record-keeping perspective, could accommodate allocating the reduction in the Federal Carbon Charge, associated with the RNG volumes acquired under the proposed Voluntary RNG Program, to the Federal Carbon Charge – Facility Variance Accounts (“FCCFVAs”), as opposed to the Federal Carbon Charge – Customer Variance Accounts (“FCCCVAs”), but does not believe it would be appropriate to do so.

The approved accounting orders for the FCCFVAs state their purpose is to record the variance between actual facility carbon costs and the actual facility costs recovered in rates. As such, in order to accommodate the above noted allocation the RNG volumes procured would have to be deemed to be displacing facility-related volumes, thus reducing the actual facility-related carbon costs incurred. However, the intent of the Program is to offer access to clean and affordable energy to customers, and as such to offset customer volumes; not the Company’s facility volumes. While Program participants are not promised a specified volume of RNG, the intent of the Program is that all acquired volumes will displace traditional natural gas purchases for customers. This intent is core to the Company’s plans to communicate and market the Program to customers. The displacement of customer volumes, as opposed to facility volumes, is also one of the reasons why the Program is being offered to general service system gas customers (for whom the Company supplies gas), as opposed to all general service customers. The Company is not supportive of the Program being used to displace facility-related volumes, as that is not the design proposed for the Program, and the Company anticipates difficulty marketing this alternative approach in a manner that is both clear and compelling to potential participants.

ENBRIDGE GAS INC.

Undertaking Response to Summitt

To revise the summary chart to include Énergir's application before the Régie.

Response:

Program Name	**Program Type**	**Program Start Date**	**Program Volumes**	**Program Participation**
Énergir	Energy-based Program	• The program came into effect in 2020 in response to government regulation.	• Énergir is offering RNG on a voluntary basis to residential and business customers. Énergir has a mandatory requirement to inject a minimum of 1% of the total natural gas distributed through the company's system to be RNG as of 2020, and increase that to 5% by 2025. • The 1% requirement in 2020 represents approximately 60 million m³ (2.3 million GJ).	• Demand for the program is currently higher than available supply, subscribing customers are put on a waiting list.

ENBRIDGE GAS INC.

Undertaking Response to PP

In relation to the approximately one thousand contract rate customers, to advise (on a best efforts basis) of how many would have moved RNG through the Enbridge system, and then to compare those volumes to what would be "done through this program".

Response:

Enbridge Gas is not aware of any RNG volumes that have been, or are currently being, delivered into its gas distribution system by large volume contract rate customers by way of direct purchase arrangements. As such, it is not possible to compare such volumes of RNG to what is expected to be introduced to the Company's gas distribution system as a result of Enbridge Gas's proposed Voluntary RNG Program.

ENBRIDGE GAS INC.

Undertaking Response to CCC

To provide all correspondence with the Ministry of Energy, Northern Development and Mines with respect to this particular program and any other programs.

Response:

Attached to this response is a copy of a presentation made by Enbridge Gas to the Ministry of Energy, Northern Development and Mines in September 2019 describing the Company's plans for a Voluntary Renewable Natural Gas Program. To the best of the Company's knowledge, this is the latest presentation describing the Program before the date when Enbridge Gas filed this Application.

Also attached to this response is a copy of speaking notes for a meeting between Enbridge Gas and the Ministry of Energy, Northern Development and Mines in February 2020, just prior to the filing of this Application. This information was also shared with personnel from the Ministry of the Environment, Conservation and Parks. To the best of Enbridge Gas's knowledge, this is the latest "correspondence" about the Program communicated to government officials before the date Enbridge Gas filed this Application.

Enbridge Gas declines to produce other correspondence/communications between it and government of Ontario officials relating to other possible versions voluntary RNG program because those documents relate to earlier versions of potential programs that are not being brought forward for the Board's approval and therefore are not relevant to the proposal that Enbridge Gas has submitted to the Board for approval in this proceeding.

Voluntary Renewable Natural Gas Program

ENBRIDGE®

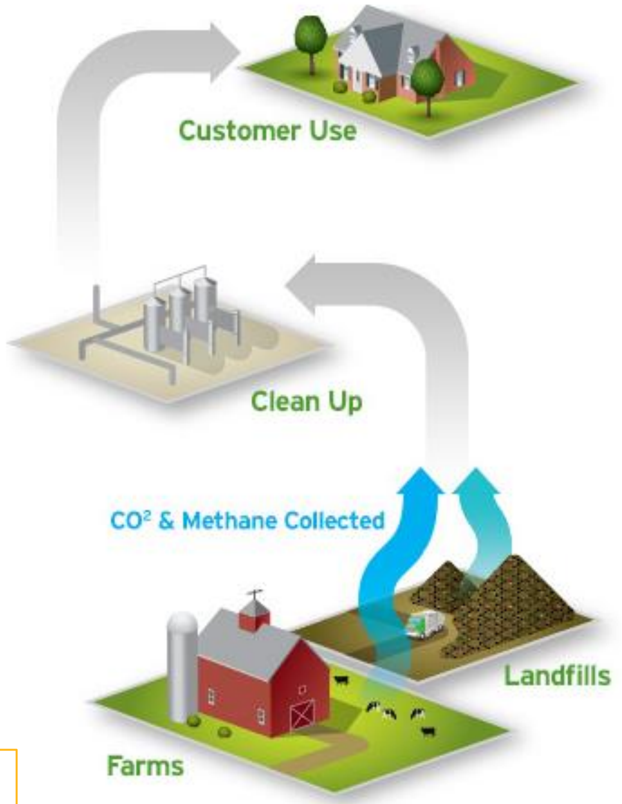
September 2019

Background

ENBRIDGE
Life Takes Energy

Benefits of Renewable Natural Gas (RNG)

- RNG is a low-emission extension of the existing natural gas distribution system, which uses waste from landfills, municipalities and farms.
- Enbridge's voluntary program will enable customers to support the introduction of RNG into the Company's gas supply while insulating non-participating customers from incremental RNG costs.
- Supports future investment and employment opportunities in Ontario's green sector while offering consumers low-cost options to reduce GHG emissions.



The Made-in-Ontario Environment Plan includes a commitment to "*require natural gas utilities to implement a voluntary renewable natural gas option for customers.*"

Proposed Program Design

A fixed monthly charge for voluntary customers

ENBRIDGE
Life Takes Energy™

- Enbridge would offer residential customers an option to pay $2 / month premium on their natural gas bill to support the introduction of RNG content in Enbridge's gas supply portfolio.
  - Participating customers will have a minimum of one-year commitment.
  - Participating customers will receive annual reporting and updates (e.g. RNG volumes procured, GHG emission reduction benefits).
- Non-participating natural gas customers will have no rate impacts.
  - Enbridge will procure RNG using short-term or spot supply contracts.
  - Enbridge will use voluntary customer contributions to cover both administration and RNG procurement costs associated with the program.
- Initial design is low-cost, leverages existing infrastructure (e.g. billing systems) and is scalable to address future demand (e.g. local production).

Key Deliverables

In the First Five Years…

ENBRIDGE
Life Takes Energy™

~28,000 participants

~18,000 GJ/Year

~3,500 tCO_2e GHG emission reduction

Supports Ontario RNG Production

~800 Cars off the road

Next Steps

- Confirm support, alignment from MECP, MENDM.
- Continue discussions with external groups and industry associations (e.g. Biogas Association).
- Enbridge files Voluntary RNG Proposal as part of our 2020 Rates Application (October 18, 2019).
  - Depending on regulatory approvals, Enbridge aims for program launch as early as Q2 2020.

Appendix

2018 Market Research

Key Findings - Unaided Willingness to Pay (monthly)

- Customers offer a wide range of values when indicating the maximum monthly premium they are willing to pay, and generally increase their amount as the % of RNG increases.
- 47% of all customers are willing to pay something for RNG, with no consideration for percentage blend of RNG.
- 3% of customers are willing to pay at least $2 for RNG, with no consideration for percentage blend of RNG.

Range of Prices mentioned *(unaided)* *accepted responses from 0-99*	**No % RNG consideration**	**2% RNG**	**5% RNG**	**10% RNG**	**50% RNG**
	All customers (n=1212)	**All customers willing to pay something at no % consideration (n=928)**			
$0 / not willing to pay anything	24%	4%	3%	2%	2%
$1	1%	6%	3%	2%	2%
$2	2%	8%	6%	3%	2%
$3 to $4	1%	3%	3%	4%	2%
$5	9%	14%	14%	10%	10%
$6 to $9	1%	1%	5%	4%	2%
$10	14%	10%	9%	13%	13%
$11 to $15	4%	3%	5%	5%	6%
$16 to $20	7%	1%	4%	6%	9%
$21+	8%	7%	8%	9%	15%
Mean (excl. 0) [median]	**$17.21 [$10]**	**$12.22 [$5]**	**$13.16 [$7]**	**$14.82 [$10]**	**$18.93 [$12]**
Don't know / not sure	30%	41%	40%	40%	39%

Q: What would you say is the absolute maximum amount of money you would pay as a premium, or extra per month, to ensure that a proportion of the natural gas used in homes and businesses in Ontario is renewable natural gas?

Proposed Program

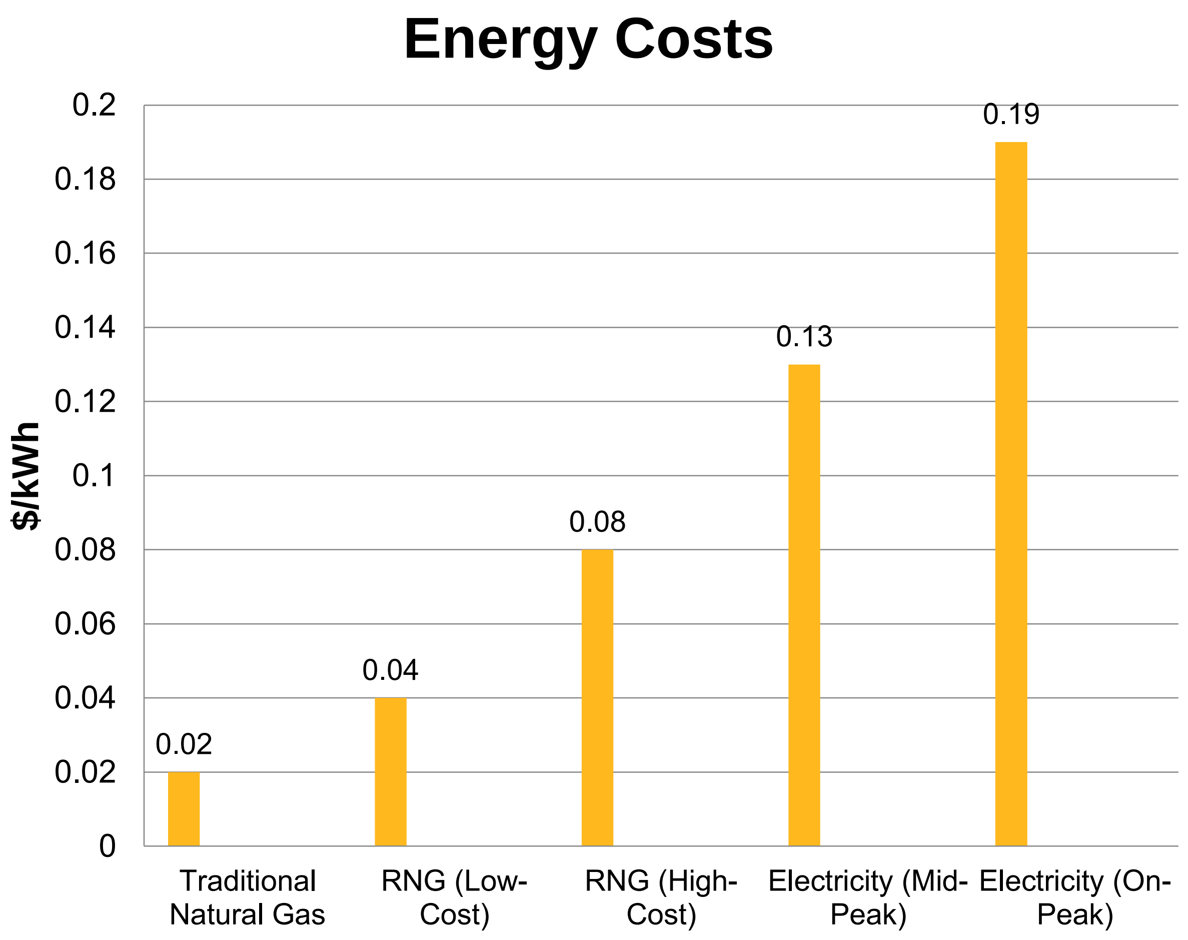
Participation Estimates

Program Year	1	2	3	4	5	6	7	8	9	10	Total
Estimated Customer Participation (#)	21,087	22,844	24,602	26,359	28,116	29,873	31,631	33,388	35,145	36,902	
RNG $ Collected From Participants	$506,090	$548,264	$590,438	$632,613	$674,787	$716,961	$759,135	$801,309	$843,483	$885,658	$6,958,738
Potential RNG Purchases (GJ)	9,814	11,822	13,830	15,839	17,847	24,617	26,625	28,634	30,642	32,650	212,321
Potential RNG Purchases (m3)	263,530	317,459	371,388	425,316	479,245	661,045	714,974	768,903	822,831	876,760	5,701,452
GHG Reduction (substitution value) tCO2e	494	595	696	797	898	1,239	1,340	1,441	1,542	1,643	

Energy Costs Comparison

RNG provides an affordable option for emissions reductions

- Based on current rates natural gas is 68% more affordable than electricity and 65% less than heating oil.
- After conservation, RNG is one of Ontario's lowest-cost carbon abatement options.
- Some municipalities have already approached Enbridge to assist in turning their biogas from landfills, waste water treatment plants and organic programs into RNG for municipal transportation (e.g. Hamilton, Toronto, Peel, Durham).



Filed: 2018-01-19 EB-2017-0255 Exhibit B. Energy Probe Attachment 7 Page 3 of 4

Overview of Enbridge's Voluntary RNG Program Proposal

Updated: 28 February 2020

Topline Messages

- RNG uses methane produced from the decomposition of organic waste, which can be used in place of traditional natural gas for heat and transportation. This costs less than electricity and reduces the overall carbon intensity of natural gas.
- The Made-in-Ontario Environment Plan signals that the Provincial Government will require utilities to implement a voluntary renewable natural gas (RNG) option for customers.
- Enbridge's voluntary RNG program design is small-scale and low-cost to begin, leverages existing infrastructure (e.g. distribution network, billing system), and may be scalable for future demand.
- Expected outcomes / key deliverables for the first 5 years:
    - ~28,000 participants (i.e. voluntary customers). Enbridge would coordinate with our partners on targeted marketing and outreach to maximize customer participation
    - ~18,000 GJ / year (enough to heat roughly 200 homes for a year)
    - ~3,500 tCO_2e avoided (equivalent to taking ~800 cars off the road)

Benefits for Participating Customers

- Residential customers would be given the option to pay a fixed monthly charge of $2 / month to blend in a portion of RNG onto their monthly bills.
    - Precise quantity of RNG is not defined; this depends on the cost of RNG as purchased on the North American market
    - One-year subscription may be approx. equivalent to heat a typical home for one week
    - Voluntary RNG offering would be targeted to residential and small commercial customers as the initial program beings
    - No rate increases for non-participating customers
- RNG is one of Ontario's lowest-cost carbon abatement options (behind energy conservation). Approx. price points for comparison (source: OEB filing 2018-01—19 EB-2017-0255 Exhibit B):
    - Traditional natural gas: $0.02 per kWh
    - Range of RNG prices $0.07 - $0.09 per kWh
    - Mid-peak to on-peak electricity $0.13 – 0.19 per kWh

Enbridge's Program Delivery

- Enbridge has simplified program structure to reduce administrative burden and enable easy implementation.
    - March 2020 – Enbridge to file program proposal and evidence at OEB, and coordinate communications opportunities with key stakeholders and Government of Ontario
    - Mar 26 – BioGas East Conference in Toronto
    - Fall 2020 – Target OEB decision to implement RNG program

  - Spring 2021 – First RNG procurement (North American market)
  - Ongoing – Communication to customers regarding the outcomes of the program and their contributions (e.g. RNG purchased, GHG emission reductions)

Delivering a Made-in-Ontario Solution

- Enbridge's RNG program offers a simple low-risk and low-cost option to customers. Unlike BC's program, Enbridge's will not result in rate increases to non-participating rate payers as the program leverages existing systems and does not involve long-term supply contract in the initial phase.
- Enbridge will monitor program performance regularly and may consider entering into long-term RNG supply contracts if sufficient customer demand is met.
  - With the appropriate funding and cost recovery mechanisms, Enbridge's program could be scaled to accommodate a mandatory content requirement or increased customer demand for RNG
  - Enbridge Gas also provides existing services to help RNG producers inject into the natural gas system and sell their RNG in the market
- The federal Clean Fuel Standard (CFS) may impose a compliance obligation on the natural gas sector starting January 1, 2023. One of the proposed compliance pathways available to natural gas distributors to satisfy their CFS obligation is the blending of low carbon intensity fuels with natural gas. As a result, Enbridge would be required to procure RNG as part of the Company's supply portfolio.

Reducing Administrative Burden and Red Tape

- Enbridge has simplified program structure to reduce administrative burden and enable easy implementation.
- The Province of Ontario can also support the production of RNG in Ontario, including by streamlining the approvals process for low-risk organic waste processing
  - Environmental Compliance Approval (ECA) is required for Ontario-based facilities that upgrade biogas (e.g. from municipal waste) into RNG, including:
    - P.Eng. certification followed by MECP ECA review (duplicates P.Eng. work)
    - MECP review process could take up to 1 year even for low-risk, small-scale sites
    - Facility construction is stalled pending MECP review and outcomes uncertain
  - Biogas upgrading could be recognized as a low-risk activity.
  - EASR process requires P. Eng. Certification and offers proponents faster approval timelines. MECP can define "low risk" projects (e.g. by source, size) and requirements for EASR registration.
  - <u>Action</u>: Adopt EASR for small-scale, low-risk biogas facilities in order to support investments in the development of Made in Ontario RNG sourced from organic waste.