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Moving Forward: Alberta Biogas Industry 2016

A White Paper on Policy and Economic Outlook

Prepared for: Alberta Innovates

Jonathon Alcock, Liz Brennan, Karen Haugen-Kozyra, Dr. Amit Kumar and Dr. Mahdi Vaezi

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Glossary

AAF	Alberta Agriculture and Forestry
ACCO	Alberta Climate Change Office
AD	Anaerobic Digestion
ADR	Activities Designation Regulation
AEP	Alberta Environment and Parks
AER	Alberta Energy Regulator
AESO	Alberta Electric System Operator
AOPA	Agricultural Operation Practices Act
AUC	Alberta Utilities Commission
BOD	Biological Oxygen Demand
BPCP	Bioenergy Producer Credit Program
BPP	Bioenergy Producer Program
CFS	Clean Fuel Standard
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CO_2e	Carbon Dioxide equivalent
COD	Chemical Oxygen Demand
EEG	Renewable Energies Law (Germany)
EPEA	Environmental Protection and Enhancement Act
ERA	Emission Reductions Alberta
FiT	Feed-in Tariff
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GoA	Government of Alberta
IRR	Internal Rate of Return
LCFS	Low Carbon Fuel Standard
LNG	Liquefied Natural Gas

MOU	Memorandum of Understanding
MSW	Municipal Solid Waste
Mt	Megatonne
MW	Mega Watt(s)
NERP	Nitrous Oxide Emission Reduction Protocol
NGV	Natural Gas-powered Vehicle
NRCB	Natural Resources Conservation Board
REC	Renewable Energy Certificate/Credit
REP	Renewable Electricity Program
RFS	Renewable Fuel Standard
RIN	Renewable Identification Number
RLCFRR	*Renewable and Low Carbon Fuel Requirements Regulation* – British Columbia
RMADF	Regulated Mixed Anaerobic Digestion Facility
RNG	Renewable Natural Gas
RPS	Renewable Portfolio Standard
RVO	Renewable Volume Obligation
Solar PV	Solar Photovoltaic
SSO	Source Separated Organics waste
WSP	Wire Service Provider

Executive Summary

This white paper is a culmination of strategic analysis from the Alberta biogas industry, industry and energy experts, and government representatives (see Working Group Members in *Acknowledgements*).

Analyses and recommendations are based on the current status of the biogas industry in Alberta, and incorporate experiences in building viable biogas economies in the North American and European context. In so doing, the paper identifies important lessons for successful biogas industry development in these jurisdictions, and the barriers/challenges that others have overcome. Drawing on research from Alberta, Canada, North America and Europe, we provide potential solutions and approaches related specifically to Alberta's current and evolving regulatory and energy market environments. The reader is assumed to have some prior knowledge of biogas generation technology, and recommendations regarding any protocol or regulatory frameworks that arise from the report are intended to be unbiased towards a specific technology or method.

Anaerobic digestion (AD) is considered one of the most promising technologies for practical solutions to wet organic waste management, producing marketable products, such as renewable energy (electricity or renewable natural gas (RNG)) and biofertilizers, while reducing environmental footprints and greenhouse gas (GHG) emissions. In Alberta, the substantial availability of organic waste feedstocks indicates a significant potential for a large biogas industry and its associated benefits. Forestry, agriculture, and agri-processing are cornerstone industries in Alberta and are essential to the provincial economy. These industries produce large quantities of organic wastes typically seen as a liability to industry operators, and a leading source of GHG emissions. The current focus of organic waste diversion by Alberta municipalities, for example the City of Calgary, amplifies the opportunity to capitalize on using these feedstocks sustainably to produce biogas.

The benefits of a vibrant Alberta biogas industry are:

- Provides a viable sustainable and economic option to reduce GHG emissions and generate renewable energy in-line with GoA's Climate Change Leadership Plan.
- Effective waste management from numerous sectors, capturing the nutrient value of waste while effecting appropriate landfill tipping fees and/or prolonging landfill lifetimes, or providing an effective wastewater treatment procedure. Innovation and technological expertise in biogas would label Alberta as a leader, increasing the feasibility of biogas generation while reducing capital costs over time, and potentially allowing Alberta companies to enter markets elsewhere.
- Rural economies stand to benefit from job creation, reduced costs for waste management and reduced GHG emissions.
- Integration and diversification of agri-based economies through sales of Renewable Energy Certificates (RECs) or similar markets, offset credits, bio-fertilisers and other digestate products from using low-quality/spoiled crops, animal bedding, animal wastes, and on-farm food-processing wastes.

- Enhances social license of livestock industries – Linking the livestock industry's manure outputs to a vibrant biogas industry reduces upstream methane emissions, provides opportunities for a more distributed and balanced nutrient system regionally, and recycles slow-release organic biofertilizer with more bioavailable nutrients, fewer pathogens, and reduced odours and groundwater contamination risks.

The key challenges to a successful biogas industry in Alberta and the recommended solutions to overcome them are highlighted in Table ES- 1.

Alberta's biogas industry is at a crossroads. Impediments outlined in this paper must be addressed to facilitate a strong biogas industry for the province, and allow Alberta to become a leader in biogas technology in Canada and globally. The following key recommendations are viewed as necessary to facilitate the development of a self-sustaining biogas industry in Alberta:

1. A **'Bio Carve-out' of the Renewable Electricity Program** for biogas generators, including a fixed 'standing price' for 20 years, and reduced or subsidised grid connection costs. **Continued Emission Reductions Alberta (ERA) and/or Alberta Energy Regulator (AER) capital grant financing** for up to 50% capital costs to bridge the gap to industry maturity.
2. Build on current collaborative efforts to develop a **clear permitting and regulatory pathway** for biogas proponents. A long-term, simplified solution could be achieved through changes to digestate regulations, and **development of a digestate protocol** that specifies the feedstocks and processes to produce digestate to a reliable quality standard.
3. **Increase non-energy revenue sources** through a ban or levy on landfilling organic waste, and/or development of a quantification offset protocol to include avoided upstream methane emissions.
4. **Create a provincial Clean Fuel Standard**, modelled on the BC *Renewable and Low Carbon Fuel Requirements Regulation* (RLCFRR), including Renewable Identification Numbers (RINs), in association with **research and investment in Renewable Natural Gas (RNG) infrastructure and market development**. This will also allow Alberta to take advantage of the proposed national *Clean Fuel Standard* (CFS).

Table ES- 1: Key Opportunities, Barriers/Challenges, and Recommended Solutions for a Successful Alberta Biogas Industry

Opportunities	Barriers/Challenges	Recommendations[1]
Market Access	• Electricity-producing biogas plants compete in a de-regulated market with conventional large-scale electricity generation and subsidised alternative energy technologies. • Regulations surrounding low-carbon energy production do not provide for generators exporting to the grid with capacities between 1 and 5MW. • Volatility in the de-regulated Alberta electricity market reduces investor confidence in biogas energy generation. • Connection to the existing energy grid infrastructure is geared towards conventional energy generation; connection is a lengthy and costly process inhibitive to smaller producers.	• Create a 'Bio Carve Out' of the recently recommended AESO Renewable Electricity Program (REP) for biogas generators (up to 5MW capacity) that provides an Indexed Renewable Energy Credit (REC) at a fixed 'standing price' guaranteed for 20 years. • Prioritise renewable or alternative energy grid connection with a fast-tracked application process and reduced or subsidised connection costs.
Recognition of non-energy benefits of Anaerobic Digestion	• Tipping fees for landfill disposal of organic wastes do not full consider the environmental impacts which reduces financial viability of anaerobic digestion as a waste management method. • Rural job creation and economic diversification benefits of biogas, compared to wind and solar operations, are not recognised as a benefit to rural communities. • The current anaerobic decomposition offset protocol does not account for avoided upstream or downstream methane emissions associated with anaerobic digestion of manure and food processing waste.	• Introduce a ban or levy on landfilling organic wastes, as it will allow more feedstock available for biogas facilities and other waste processing facilities and thus redirect landfill tipping fees to those facilities. • Recognise the rural job creation benefits of biogas through the introduction of a rural job creation incentive. • Research and develop an anaerobic decomposition carbon offset protocol to quantify the upstream and downstream methane avoidance benefits of anaerobic digestion.
Regulatory Streamlining	• There is no clear pathway for developers to follow regarding the permitting process for biogas projects. • Biogas proponents deal with multiple agencies who operate on different timelines, and require nested approvals. • The lack of formal working agreements between regulators can result in inefficiencies in consultation and assessment processes.	• Build upon current collaborative efforts to develop a clear permitting pathway for developers to follow. • Coordinate between relevant agencies to reduce consulting inefficiencies. • Introduce a regulatory lead to coordinate biogas proposals.

Opportunities	Barriers/Challenges	Recommendations[1]
Digestate Regulation and Market Development	• Digestate regulation depends on the feedstock source, and is consequently regulated under different regulations and jurisdictions (AOPA under NRCB or EPEA under AEP). Collaboration between AEP, AAF and NRCB has provided a good medium-term solution in the form of a "Memorandum of Understanding", which reduces regulatory burden and reduces requirements for AEP involvement. • There are no clearly defined quality standards or operating procedures for the production and use of digestate from mixed-source (third party) feedstocks. • The true value of digestate as a fertiliser (compared to manure) is not fully recognised through the current nutrient management regulations.	• Update regulations to provide a simplified and long-term solution for digestate storage and handling. • Develop a digestate policy or protocol that specifies feedstocks and associated AD operational processes to produce digestate to a standard quality, using the Ontario provincial regulations as a model. • Incent the use of digestate compared to manure, using existing initiatives such as the Nitrous Oxide Emission Reduction Protocol (NERP).
Development of a Renewable Natural Gas (RNG) Market	• Lack of awareness, regulatory incentives (such as inclusion in the *Renewable Fuel Standard* or a provincial *Clean Fuel Standard*) and technology costs are significant barriers to RNG development in Alberta. • A national *Clean Fuel Standard* is expected to take several years to develop and implement. • Infrastructure constraints exist especially in rural areas where the natural gas grid capacity may be unable to accept renewable natural gas (RNG) at times of peak production and low demand. • Use of natural gas as a transport fuel is limited to return-to-base fleets due to infrastructure competition with conventional fuels, and lack of uptake of natural gas vehicles (NGVs).	• Invest in research and infrastructure for RNG grid connection, particularly in rural areas, and clarify grid connection standards for small gas injectors. • Invest in research and refuelling infrastructure for RNG transport fuel, in consultation with the national Clean Fuel Standard. • Incent the purchase of NGVs and vehicle conversions through tax rebates and clean air policies; conversion of municipal fleets to RNG fuels would improve public perceptions. • Create a provincial market-based value for biomethane such as the through the *Renewable Fuel Standard* (RFS).
Technical support	• Lack of research and development capability in the province. • Lack of education and training programs for biogas operators.	• Expand existing research and development centres such as Alberta Innovates. • Create or encourage the development of a post-secondary biogas technology training program.

Techno-Economic Analyses of Three Biogas Models in Alberta

Three cases were developed to represent three probable biogas plants that could be developed in Alberta:

- Case 1: Pulp and Paper Mill – A forestry industry biogas plant using AD as a wastewater treatment process and using generated electricity on-site.
- Case 2 – An agricultural industry-based digester, utilising some food processing waste, and **charging tipping fees to some feedstock providers**.
- Case 3 – An agricultural industry-based digester, utilising some food processing waste, and **not charging tipping fees to feedstock providers**.

Data for the models were adapted from information provided by existing biogas operations in Alberta. The sources of revenue that were considered include electricity sales and savings, tipping fees, process efficiency savings and offset credit sales for offsetting grid electricity. The potential offset credits generated from upstream and downstream avoided methane emissions were estimated to be an additional 30% and were modelled to show the impact of this potential revenue source.

The results show that the large industrial plant is the most economically feasible operation, which under the current system of electricity sales/savings and offset credit sales, would require an average electricity sale price of $43/MWh with a 25% capital grant and $30/t$CO_2$e offset credit sale price to achieve a 5% IRR. The break-even price at 0% IRR was $58/MWh.

The agriculture-based digesters perform less well, showing break even prices of $84/MWh and $101/MWh at 0% IRR. The difference between the agriculture-based operations is accounted for by the income generated by tipping fees. Comparing case 2 and 3, it is clear that the potential revenue that could be generated through charging tipping fees is substantial. Under the current system of electricity sales and offset credit sales, both these cases would require significant increases to electricity sale price and/or offset credit price to achieve a 5% IRR (Figure 7 and Figure 10).

Inclusion of credits generated by avoided methane emissions reduces the minimum electricity sale price required in each case by $5-6/MWh. These offsets could be a significant source of revenue for biogas operators but will not make biogas projects economically feasible without other sources of revenue, or an increase in the price of carbon or electricity.

Comparison of the cost of biogas with wind and solar PV generation technologies is difficult due to a lack of Alberta-specific research at the appropriate capacity. However, the different business models associated with wind and solar projects, and the potential for decreasing costs of solar and wind technologies, means that a 'Bio Carve Out' of the *Renewable Electricity Program* specific to biogas operations is the recommended option for successful market access for biogas electricity in Alberta.

[1] Some of these recommendations may require more detailed techno-economic assessment before they are implemented.

Introduction

Biogas is a renewable source of methane gas typically created via the process of anaerobic digestion (AD); the microbial breakdown of organic matter in the absence of oxygen, in an anaerobic digester (Canadian Biogas Association, 2016). Digestion can proceed via wet or dry digestion methods, using one of several digester technologies, including covered lagoon, complete mix, or plug-flow. These different processes and technologies are not covered in detail in this paper as it is assumed producers will apply the method and technology best suited to a specific operation; it should be noted that any protocol or regulatory frameworks developed based on the recommendations of this report should not be biased towards a specific technology or method.

The biogas produced is usually between 50-60% methane and 40-50% carbon dioxide, with some trace gases (TEC Edmonton, 2015). Biogas can be combusted to produce electricity and/or heat, or upgraded to renewable natural gas (RNG) through removal of the unwanted carbon dioxide and trace gases. RNG is of sufficient quality to be injected into the natural gas grid, or be compressed (compressed natural gas, CNG) or super-cooled (liquefied natural gas, LNG) for use as a transportation fuel.

Use of biogas as an energy resource has a number of advantages. Compared to fossil fuels, combustion of biogas for electricity production reduces greenhouse gas (GHG) emissions by 89% (Alberta Bioenergy Producers Group, 2015). Compared to other renewable energy technologies, biogas is a consistent energy source that can provide baseload and dispatchable electrical capacity; it is not reliant on intermittent wind or solar inputs. Biogas electricity generation could continue to provide power during power outages, and can act as a black start generator, an important feature for many operations such as wastewater treatment (USDA, 2014). Similarly, production of biogas-based fuels for transport would provide a reliable fuel source should traditional fossil fuel sources be temporarily cut off, and gives further GHG emission reductions (USDA, 2014). RNG presents an opportunity to diversify energy supplies and reduce reliance on fossil fuels (Canadian Gas Association, 2014).

While the potential benefits of biogas are clear, there are many challenges to utilizing biogas as a mainstream energy source. This white paper aims to explore the potential of a biogas industry in Alberta, examine some of the challenges to, and advantages of, a large biogas industry, and provide expert opinion and recommendations on policy, regulatory and market tools that could be utilized to overcome these challenges. Our research draws on case studies from Alberta, Canada, North America and Europe, to understand common challenges and successful approaches to overcoming them.

Global trends in the Biogas field: Examination of other Jurisdictions

Realization of the potential energy to be gained from organic materials, technological advances, and development of appropriate policy and renewable energy market mechanisms, have led to a significant growth of biogas industry in certain jurisdictions. Forecasts expect the current trend to continue and increase, with AD playing a fundamental role in the global energy mix through local waste management and agricultural practices (Visiongain, 2016). A shift from current landfill gas capture operations towards AD of urban organic wastes is also forecast, as source separation of organics is incorporated into waste management policy (Visiongain, 2016) (Canadian Gas Association, 2014). It is recognized that the availability of feedstock and the regulatory environment are the two main influences on the success of a biogas industry (Visiongain, 2016). Indeed, growth has normally been achieved in conjunction with the creation of markets, financial incentives, and regulations for increased renewable energy generation.

Europe

The growth of the European biogas industry can be attributed to a number of regulatory, market and economic factors. The European Commission has developed several directives, targets and programs that have initiated thriving in biogas industries in certain jurisdictions, including:

- Targets to reduce GHG emissions to 21% below 2005 levels for aviation, large industrial and power sectors (European Commission, 2016).
- The Biofuels Directive (2003) which requires 10% of transport fuel to come from renewable sources (such as renewable CNG) and reduce the GHG intensity of transport fuels by 6% below 2010 levels, by 2020 (European Commission, 2016) (Canadian Gas Association, 2014).
- Regulations on waste management (AEBIOM, 2012).
- Capital grant schemes (AEBIOM, 2012).
- Quota requirements and creation of renewable energy markets such as the '*Certificati Verdi*' in Italy that requires electricity importers to generate a proportion of renewable electricity or purchase the renewable quota in the form of 'green certificates' (AEBIOM, 2012).
- Feed-in-tariffs such as the UK system that pays a premium for renewable electricity exported to the national grid (Feed-in Tariffs Ltd., 2016). Italy has implemented a feed-in-tariff that is fixed by law at €280/MWh for 15 years (AEBIOM, 2012).
- Voluntary commitments such as the 'Green Gas Initiative' where infrastructure providers have committed to carbon neutral gas supply by 2050 (Neuland PR, 2016).

In Ireland, multinational corporations, who are the largest consumers of energy in the country and who have their own carbon reduction targets, may be promoting biogas as a renewable energy source for heat, electricity and cooling for industrial operations (Murphy, 2015).

The German biogas industry deserves special mention here; it is by far the largest biogas producer in Europe producing 41,000GWh per year; 5% of total electricity demand (AEBIOM, 2012). This has been

achieved in part through providing financial incentives that make biogas competitive with fossil fuel produced electricity. Feed-in-tariffs differentiate between technology used, production capacity, and feedstock, and are available for a 20-year period. This guaranteed power price mechanism creates a framework for secure investments from the private sector who are willing to invest in the high capital costs. It is estimated that approximately 80% of the existing biogas facilities in Germany are predominantly agriculture-based, and that more than 80% of German biogas is produced from energy crops grown specifically for AD (Visiongain, 2016). The vast majority of German biogas plants are smaller plants owned by individual farmers or small businesses, who utilise both electricity and heat (including seasonal heat storage) produced by combined heat and power (CHP) technology (Bell, Trip Report - International Biogas Conference, 2015). While these statistics demonstrate how successful biogas industries tend to begin in agriculture, energy crops are expensive for biogas operators to buy, and their growth displaces land used for food production. Generous feed-in tariffs make energy crops more economically productive. The German biogas sector is expected to grow further to add 50% to today's capacity by 2020, with a trend towards increased use of agricultural and municipal wastes to reduce reliance on energy crops (Visiongain, 2016).

The success of the tools and measures implemented in Europe show that the typical barriers of capital investment, feedstock supply and technology scale are not significant when appropriate financial incentives are provided, an opinion mirrored by current biogas producers in Alberta (Canadian Gas Association, 2014; Michalski, 2016).

United States

According to a study by the U.S. government, there are over 2,100 biogas producing sites in the U.S., with the potential for 11,000 more with appropriate support (United States Government, 2014). The majority of operational sites are wastewater treatment plants, totaling 1,241 operations, with landfill gas projects, on-farm ADs and standalone ADs accounting for 654, 247 and 38 sites respectively (American Biogas Council, 2016). The landfill sector has been particularly successful due to the combination of 3rd party investment and a strong development community, but technological developments in blending organic feedstocks for AD suggest that the current balance is likely to change (United States Government, 2014). The largest growth potential for the U.S. biogas sector is in the agricultural sector where it is estimated over 8,000 dairy and swine farms could include biogas production in their operations. U.S. federal agencies plan to grow the sector using a number of methods:

- Strengthen markets for biogas systems and non-energy products through a fast-track review of federal procurement guidelines to ensure products are eligible and promoted.
- Improved collection of financial and technical data to track performance and attract private investment.
- Utilization of existing programs that recognize agri-conservation practices to include benefits of digesters and increase financial and technical assistance for on-farm installation.

- Development of standards and fee structures for electrical and gas pipeline interconnection and gas injection.
- Ensuring fair market access of biogas products.
- Development of best management practices for the use of digestate products and land application with the potential to induce nutrient-trading programs.

Further information on specific case studies of the biogas industries in Europe, the U.S., Canada and Alberta is presented in *Appendix 2: Case Studies*.

Background and potential of biogas technology in Canada and Alberta

In Canada it is estimated that the total potential production of RNG from all sources is equivalent to over half of the current annual consumption of natural gas nationally. Farm-based anaerobic digesters and wastewater treatment operations are expected initially to be the main source of RNG (Salim Abboud, 2010), (Canadian Gas Association, 2014).

Alberta has a significant opportunity to develop a thriving biogas industry, based on the considerable biomass feedstock resources across the province (Bell, An Organic Waste Inventory for Alberta's Agrifood Sector, 2015) (Ghafoori, 2007) (Alberta Bioenergy Producers Group, 2016) (TEC Edmonton, 2015) (Behrens & Sultana, 2014). The agriculture and food industry is the second largest export industry in Alberta, and the food and beverage processing industry was Alberta's second largest manufacturing sector in 2013 (Bell, An Organic Waste Inventory for Alberta's Agrifood Sector, 2015). Southern Alberta is home to some of the largest feedlot operations in North America, and as a province, Alberta has approximately 5 million head of cattle (41% of the total national total), and 1.5 million hogs (11% of the national total) (Alberta Bioenergy Producers Group, 2016). These sectors produce a substantial amount of organic waste which is often seen as a business liability due to disposal and odour control costs (Bell, An Organic Waste Inventory for Alberta's Agrifood Sector, 2015; Clean Air Streategic Alliance, 2008). Of this waste, a significant proportion (75%) is expected to be sourced for manure-generated biogas (Alberta Agriculture, 2006).

Another significant source of waste organic matter in Alberta is Municipal Solid Waste (MSW) and Source Separated Organic (SSO) household waste. Alberta is the highest generator of residential waste per capita in Canada (TEC Edmonton, 2015). Approximately 40% of household waste is organic, which, if separated at source, can be added to manure feedstocks to improve methane yield during AD (Alberta Bioenergy Producers Group, 2016) (TEC Edmonton, 2015).

It is estimated that if all the organic waste currently produced in the province was utilised for electricity generation, it could provide up to 1,100MW of continuous renewable electricity capacity (9% of the current total Alberta grid capacity and 52% of current grid capacity from renewable sources) (AESO, 2016) (Haugen-Kozyra, Mihajlovich, Driver, & Li, 2010). A proportion of this waste is unlikely to be available or suitable for digestion, but we can reasonably assume that approximately 30-50% of the total available

organic waste could be utilised for biogas electricity generation. This would convey a potential 330-550MW capacity from biogas electricity generation in Alberta, equivalent to 2.1-3.4% of the current total Alberta grid capacity, 12.2-20.4% of current total Alberta grid capacity from renewable sources (approx. 2,700MW), and 6.6-11.0% of the additional 5,000MW from renewable sources proposed by the AESO Renewable Electricity Program (AESO, 2016).

Biogas and its Role in the Bio-Economy and Low Carbon Economy

There are numerous benefits to including biogas in the bio-economy. Use of biogas to produce electricity, or processing to CNG/RNG for transport fuel, reduces reliance on fossil fuels and associated market volatility. Diversifying energy sources also leads to a more sustainable and resilient energy sector, which in turn promotes economic resiliency. At current energy prices, biogas is seen as an expensive energy source when other benefits are ignored and projects are viewed from a strictly energy-centric perspective.

In addition to diversifying the energy sector, a large biogas industry in Alberta would aid diversification and economic stability of the agricultural sector. Widespread use of agricultural feedstocks would support novel crop development, diversification and agronomic innovation, reduce market dependence for primary crops, and potentially create a market for low quality or spoiled crops and residues (Alberta Bioenergy Producers Group, 2015).

Production of bioenergy products can also open export markets in the form of physical products, such as high quality fertilizers, fiber or feedstocks for renewable plastics or chemicals; and economic products for renewable energy markets in the form Renewable Energy Credits (RECs) or Renewable Identification Numbers (RINs) in California's Low Carbon Fuel Standard (LCFS). An example is the sale of RECs from the production of renewable natural gas in Quebec to the California renewable energy market (Canadian Biogas Association, 2016). It should be noted however that export sales of this kind would render the operator unable to receive credits for the same product under a comparable Canadian system.

Status of Alberta Biogas Industry

Canada has not seen the sustained, substantial government support that has been provided in Europe, and as such the biogas industry is still in the early stages of development with just 72 functioning AD facilities; most of these are located in Ontario (Visiongain, 2016). In 2016, 24 new facilities were forecast to come online in Canada, with an industry investment of $192.2M, 6% of which is for operation and maintenance; 94% is for capital expenditure (Visiongain, 2016). Farm-fed facilities dominate the early part of the forecast until waste management strategies divert organic waste from landfill to make SSO waste a suitable feedstock (Visiongain, 2016).

To date there has been some interest in utilizing the energy potential of Alberta feedstocks, especially when the '9-Point Bioenergy Plan' was launched by the Government of Alberta in 2006. The initial interest, however, has not given rise to a thriving biogas industry in Alberta today. Table 1 outlines the state of current biogas projects in Alberta. Three municipal wastewater treatment plants and up to six landfill gas

plants employing biogas to produce electricity are excluded here due to the different business case and motivators behind them.

Table 1: Status of the Alberta Biogas Industry

Status	Category	Number of operations
Currently Operational (excluding municipal wastewater plants)	Producing Electrical Power	3
	Producing Heat only	3
	Wastewater Treatment Process – flared biogas	3
Proposed Projects	Commissioning Staff	1
	Seeking Capital Investment	2
Non-operational	Technological Issues	3
	Financial Issues	2
TOTAL		17

Excluding three municipal wastewater treatment and six municipal landfill gas recovery operations, we know of 17 biogas projects that have been proposed or built in Alberta; three of these applications received investment from the Bioenergy Producer Credit Program (BPCP) and/or the Bioenergy Producer Program (BPP) (Viresco Solutions, 2015). Of the three proposed projects, two have issues raising capital financing, one is commissioning. There are currently 9 operational plants that either flare the waste gas, or use biogas to produce electricity or heat. Three plants are known to have ceased operation due to technology failure, and one plant is currently in receivership due to economic challenges.

Characterization of Available Feedstocks in Alberta

The potential feedstock resource in Alberta is large and varied, including forestry residues, agricultural residues, food processing waste, and municipal solid waste. Data collection of waste generated by these sectors is known to be deficient. Table 2 shows conservative estimates for some subsectors, excluding forestry residues and wastewater treatment facilities.

Table 2: Estimated Organic Waste by Subsector

Source	Organic Waste (dry tonnes per year) *	Percent of Total
Livestock (Manure)	2,560,000	76%
Livestock (On-farm dead)	70,000	2%
Food-processing	500,000	15%
Grocery Store	50,000	1%
Yard Waste	200,000	6%
TOTAL	3,380,000 (282,000 per month)	

*Data taken from (Bell, An Organic Waste Inventory for Alberta's Agrifood Sector, 2015)

It is clear from this analysis that on-farm manure wastes are a significant source of organic feedstock in Alberta. At present, land application is by far the most common disposal method for manure wastes (Bell, An Organic Waste Inventory for Alberta's Agrifood Sector, 2015). It is estimated that 60% of Alberta farms with livestock store manure in some way, for an average of six months (The Prasino Group, 2012). Approximately 1% of livestock manure goes to energy generation operations in Alberta, while 2.5% is sold as compost (Bell, An Organic Waste Inventory for Alberta's Agrifood Sector, 2015).

The majority of food processing and grocery store organic wastes are disposed by landfill, incurring fees, and are thus seen as a liability to the company (Bell, An Organic Waste Inventory for Alberta's Agrifood Sector, 2015). Yard waste is also usually landfilled, or sometimes composted. The Alberta Government has estimated that in total 600,000 tonnes of yard and garden waste, plus kitchen scraps, could be diverted from landfills every year (The Province of Alberta, 2007). A study by the Water Environment Research Foundation (2012) concluded that landfills have the highest carbon footprint and high financial costs, and that source separated food wastes should be processed in an AD to incur the lowest carbon footprint at an intermediate financial cost.

Locations of organic wastes in Alberta show that there is potential for successfully blending feedstocks to improve biogas outputs. Excluding forestry residues, organic waste sources are generally located in the south of the province, especially in Lethbridge County and “feedlot alley” with a high concentration of feedlot operations producing manure, in addition to slaughterhouse and food processing wastes. The majority of food-processing waste tends to be consistent year-round and it is estimated that manure production would stay “fairly constant year-round” (Bell, An Organic Waste Inventory for Alberta's Agrifood Sector, 2015). Larger companies also tend to produce larger amounts of more homogeneous wastes. The proximity and suspected consistency of organic waste suggests that mixed feedstock supplies will not initially be a limiting factor for biogas industry growth and would allow for optimisation of the

biological process, and production of uniform and reliable energy and non-energy products (TEC Edmonton, 2015).

Grocery stores and yard wastes in populated areas are another concentrated source of organic wastes that often have existing associated waste management infrastructure. Unlike agricultural and food processing feedstocks, supplies from these sources tend to vary seasonally: yard waste exhibits seasonal highs in spring and fall, remains high in summer, and is almost absent in winter; grocery store wastes are more consistent but tend to peak during holiday periods (Bell, An Organic Waste Inventory for Alberta's Agrifood Sector, 2015). Trends in waste management suggest that disposal of organic waste in landfill will become regulated or banned, and that curbside collection of SSO wastes will become the norm. This seems especially true for Alberta which is the only province to regulate landfills based on GHG emissions (Alberta Environment and Parks, 2015). Landfill-based ADs have a number of infrastructure advantages, including existing odor control methods, infrastructure for transportation of waste, space for AD construction, proximity to the energy market, and a potential outlet for digestate, if composting facilities exist on-site (Canadian Gas Association, 2014).

Socio-Economic Benefits for Alberta of a thriving Biogas Industry

This section describes some of the well-documented benefits of an AD business, with an emphasis on the Alberta context in the current economic situation. An understanding of the business benefits sets the stage for an evaluation of the true value that AD provides.

Rural Economic Development

Anaerobic digestion facilities tend to support rural economic development through both their rural locations, opportunities for job creation, and the nature of the processes involved. Resilience and integration of rural economies are also key benefits to a thriving Alberta biogas industry. Based on three existing biogas facilities considered in a previous study, it is estimated that 173 direct and 58 indirect jobs are created with an additional $8M GDP per 50MW capacity of electricity generated from biogas (see Table 14 in *Appendix 1: Biogas Economic Impact by Capacity*) (Viresco Solutions, 2015). If the total potential generation capacity from biogas in Alberta is 1,100 MW, and a deduced reasonable potential capacity is 330-550MW, there is a reasonable potential for between 1,142 and 1,903 direct and between 382 and 638 indirect jobs, with between $52M and $88M additional GDP to be realised from an Alberta biogas industry (Haugen-Kozyra, Mihajlovich, Driver, & Li, 2010) (Viresco Solutions, 2015). Table 3 explains the key benefits of a rural biogas industry in Alberta.

Table 3: Rural Economic Development Benefits of a Biogas Industry in Alberta

Benefit	Explanation
Job Creation and GDP	• The creation of jobs in a rural context remains an important factor for rural community resiliency, and AD projects require both skilled and unskilled positions (Alberta Bioenergy Producers Group, 2015). • Temporary jobs are created during the design and engineering phase, as well as the construction phase (USDA, 2014). • Permanent jobs are created in the maintenance and operation of the facility, as well as the collection and delivery of feedstock and digestate. • Three operating biogas facilities (totalling 4.05 MW installed capacity) in Alberta considered in a previous study supported 14 direct and 5 indirect jobs, and created an additional $0.65 M GDP impact in the years 2007 – 2014 (Viresco Solutions, 2015).
Support for rural agriculture and agri-processing economies	• Anaerobic digestion systems provide environmentally-beneficial waste management options, and thereby a market for agricultural or agri-processing materials, including low-quality or spoiled crops or crop residues, used animal bedding or animal wastes, food-processing waste materials, or wastewater that is high in COD/BOD. The use of such products in an AD context either eliminates or reduces a waste disposal cost for the business or entity providing the feedstock.
Integration of the rural economy and long-term resilience	• Other economic activity and benefits resulting from AD activities can include (Alberta Bioenergy Producers Group, 2015) (USDA, 2014): - Tipping fees for accepting organic waste materials; - Carbon offset credits or RECs or an equivalent environmental asset; - Nutrient-rich bio-fertilizer that recycles nutrients back to the land; and, - Extension of the life of a local landfill if organics are diverted from it.

Long-term Economic Benefits

Following on from the rural economic development prices described above, Table 4 describes the long-term economic benefits of anaerobic digestion.

Table 4: Long-term Economic Benefits of a Successful Biogas Industry in Alberta

Benefit	Explanation
Waste management and opportunities to pursue organic waste diversion goals	• AD can play a key role in managing organic wastes, but also capturing the nutrient value of the waste in a form that can be re-applied to agricultural land. • Landfill tipping fees have been linked to fuel prices by some analyses (Informa Economics, 2013). If fuel prices increase in the future, the avoidance of landfill tipping fees in favor of AD may become more compelling.
Potential for widespread use of organic wastes from all sectors	• More AD facilities deployed across the province increases potential for blending of feedstocks from various sources, since the average hauling distance to an AD facility should decrease (USDA, 2014). • This could be a challenge in Alberta with a distributed population outside of a few larger centers. If new AD facilities are located close to areas with substantial organic feedstock, then potential for additional feedstock use may be realized.
Innovation and technology deployment will lower AD capital costs, increase profitability, and label Alberta as a leader in AD technology	• The cycle of innovation and deployment is likely to drive down the costs of building AD facilities, as is generally the case with renewable energy technologies. • Although biogas is a proven technology in Europe, there is still the potential to reduce the initial capital costs of an AD facility in Canada as the number of plants increases, the technology matures in a Canadian context, and more confidence is developed within the Alberta sector in terms of feedstock blending and digestate handling. • An overall reduction of capital expenditure costs would, in part, lead to the long-term economic viability and profitability of the AD industry.

GHG Reduction Potential and Abatement Costs

There are several mechanisms through which AD and the resulting biogas can work to lower GHG emissions. These include:

- Avoided methane emissions from upstream organic waste storage (particularly manure lagoons);
- Avoided GHG emissions from traditional organic waste disposal methods, such as landfill, incineration, and stockpiling;
- Offset of conventional electricity production through combustion of biogas;
- Offset of conventional heat production through combustion of biogas (including heat recovered from electricity generation);
- Blending of upgraded RNG with conventional natural gas either in the natural gas grid or as transport fuel; and/or,
- Use of processed digestate as a bio-fertilizer, as an alternative to inorganic fertilisers or untreated manure.

Emissions risks associated with AD facilities include accidental flaring or venting of methane emissions, and fugitive emissions from the feeding system, digesters, and digestate (Li, 2015). However, these risks are relatively small scale, and can be avoided with best practices, including solid/liquid separation post-digestion, covered digestate storage lagoons, and regular facility maintenance. Operators have an economic and environmental motivation to reduce fugitive emissions, which are suggested to be less than 3% in Alberta biogas systems (Haugen-Kozyra, Boyd, Janzen, & Li, 2011).

Table 5 describes some of the methods that GHG emission reductions can be achieved through the employment of biogas technology.

Table 5: Types of GHG Reductions that could be realised with a Successful Biogas Industry in Alberta

Method	Explanation
Generation of electricity	• The carbon intensity of electricity generated from biomass is low; the average of Alberta facilities was calculated to be 89% lower than the provincial grid average (Alberta Bioenergy Producers Group, 2015). • Energy generation at AD facilities depends on the energy content of the feedstock materials, but a feasible range of power production is 240 – 480 kWh per tonne of feedstock (TEC Edmonton, 2015). • Compared to other renewable energy sources, electricity generation from biogas offers significant advantages, being a consistent, reliable energy source not significantly affected by weather conditions. • With further technological improvements and associated reduced equipment costs, biogas could be refined and stored as CNG or LNG, permitting storage of energy to correspond with electricity demand (Zafar, 2015). • A typical 100,000 tonne AD facility could displace a 4 MW coal or natural gas facility, and reduce 14,000 – 28,000 tonnes CO_2e by displacing grid electricity per year (TEC Edmonton, 2015). • The use of a reasonable fraction of all the organic waste in the province could provide in the region of 330-550MW of continuous renewable electricity capacity, equivalent to 2.1-3.4% of current total grid capacity, and 12.2-20.4% of current grid capacity of renewable generation sources (estimated from a total potential capacity of 1,100MW from all organic waste in Alberta), and 6.6-11.0% of the 5,000 MW additional renewable supply proposed by the AESO Renewable Electricity Program by 2030 (Haugen-Kozyra, Mihajlovich, Driver, & Li, 2010) (AESO, 2016).
Organic waste diversion	• Organic waste diversion presents an immediate opportunity to reduce GHG emissions. Alberta has one of the highest rates of waste generation per capita in Canada, and there are at least 600,000 tonnes of yard and garden waste, lawn clippings, and kitchen scraps that could be diverted from landfills, to compost facilities or AD facilities (Behrens & Sultana, 2014). • Management of wastewater, manure lagoons, manure piles, food processing waste and other sources of organic wastes through AD achieves GHG emission reductions through reduced storage times and capture of GHG emissions (The Prasino Group, 2012). In Alberta manure is stored on-site for an average of six months; the management of this manure with AD reduces storage time preventing uncontrolled methane emissions. • Diversion of available organic waste to an AD facility could result in an estimated net emission reduction of 213,690 tonnes CO_2e/year (Behrens & Sultana, 2014). • A typical 100,000 tonne AD facility could reduce up to 50,000 tonne CO_2e if methane avoidance from landfills is considered in addition to electricity generation (TEC Edmonton, 2015).

Method	Explanation
Use of Renewable Natural Gas (RNG) as transportation fuel	• Use of renewable natural gas offers substantial opportunities for GHG emission reductions. Using RNG as a transport fuel, whether blended with natural gas or not, can substantially reduce GHG emissions when compared to conventional fuels (Canadian Gas Association, 2014). • The Canadian Gas Association (2014) published an optimistic estimation of the carbon offset potential associated with the use of RNG as a transportation fuel, stating up to 108.9Mt CO_2e/year across Canada, or 13.28 Mt CO_2e/year in Alberta, which likely takes into account displaced fossil fuel life cycle emissions.

Avoided Nutrient Loading and Livestock Industry Sustainability

Alberta is home to extensive livestock and food processing industries that generate considerable quantities of manure and agri-processing wastes, including specified risk materials. These wastes result in substantial financial and environmental disposal costs. Anaerobic digestion offers solutions to a number of issues involved in managing the disposal (or land application) of manure and other nutrient-rich organic wastes, as described in Table 6. Key benefits of AD to nutrient loading and the livestock industry are:

1. Significant pathogen reducing effect, with as much as 95-98% of common pathogens eliminated (PAMI, 2014) (Saunders & Harrison, 2013).
2. Reduced volume and potential for more efficient transport, particularly with additional and often simple processing.
3. Opportunities to produce value added products through nutrient recovery and dewatering to produce a nutrient balanced biofertilizer. These products reduce the potential for nutrient loading in water bodies due to more bioavailable and homogenous nutrients, and greater potential for transportation of digestate (PAMI, 2014) (Saunders & Harrison, 2013).
4. The digestate product may act as a soil pH buffer (PAMI, 2014).
5. Application of digestate has been shown to increase crop yields in Alberta, compared to the application of untreated manure (PAMI, 2014).

Table 6: Nutrient and Agri-Waste Management Benefits of a Biogas Industry in Alberta

Theme	Explanation	Benefits of Anaerobic Digestion
On-farm wastes, manure storage, and land application	• The practice of storage and land-application of manure is common in Alberta and doesn't always balance with crop requirements, leading to accumulation of nutrients in some areas (The Prasino Group, 2012). To avoid nutrient (especially phosphorus) loading, an extensive land base is required; transportation costs of untreated manure limit the feasibility for spreading at greater distances from the manure source. As a result, nutrient loading can, and does, occur in areas with intensive livestock farming. • Pathogens found in livestock manure pose a threat to humans where they are land applied to crops, especially those eaten raw such as fruit and vegetables (PAMI, 2014). • Pathogens and weed seeds can also pose a threat to the crops themselves, especially from the land application of plant residues. • Odour management is an important consideration in the livestock industry; manure management and application is a significant source of odour issues (Alberta Agriculture and Rural Development, 2011).	• Opportunities for additional processing of the digestate (solid-liquid separation and nutrient recovery) allows for more economical hauling of a drier and nutrient balanced product to wider land base. This reduces nutrient leaching risks and increases the market for value- added products (Informa Economics, 2013) (PAMI, 2014). • A digestate product with more homogenized nutrients and nitrogen in the NH_4+ form allows efficient use by plants. Application of digestate has been shown to increase crop yields in Alberta, compared to untreated manure (PAMI, 2014). • Digestate has a smaller carbon footprint than conventional inorganic fertilisers (PAMI, 2014). • AD has been found to significantly reduce pathogens and weed seeds in the digestate product. Greater pathogen reductions are achieved with longer storage periods, higher temperatures, and changes in conditions such as pH (PAMI, 2014). Additional pasteurisation to ensure greater pathogen reductions is an efficient and easily implementable step. • As a confined treatment process, AD facilities would reduce storage time for manure and allow for better management of pens and land application. Correct handling, storage and application of digestate assists in odour management in the livestock industry (Al Seadi & Lukehurst, 2012). • AD of manure offers solutions to both reduce manure storage times and reduce odours from land application (Page, et al., 2015). • Implementation of AD as a waste management strategy in conjunction with the livestock sector would decrease the environmental footprint of the industry, and enhance social license to operate.

Theme	Explanation	Benefits of Anaerobic Digestion
Waste management of agri-processing wastes	• Nutrient-rich organic wastes are costly for processors to dispose through landfilling, incineration or composting. • Traditional disposal methods can incur detrimental environmental impacts.	• Use of AD as a waste management procedure would allow effective treatment of organic food processing and agricultural wastes at a lower cost to the agri-processor and the environment. • Some Alberta-based food-processing plants currently employ AD as a waste management procedure and gain a reasonable payback period including the use of biogas for heating and power. • The strong pathogen reducing effect of AD, and the improved availability of nutrients in the digestate allows nutrients to be recycled and land applied with the digestate (PAMI, 2014).

Biogas Sustainability for Albertans

The above discussion describes the social and environmental benefits inherent to an AD business model; AD creates new markets for agricultural materials and environmentally-beneficial strategies for waste management, while supporting the economic resiliency of rural communities. Biogas-to-electricity systems also provide a consistent, reliable, low-carbon baseload electricity supply capacity which can be dispatched to meet demand, a significant advantage over other renewable electricity sources. CHP and heat storage technologies can also be employed to utilise heat produced during electricity generation, a feature that would enhance sustainability, especially for on-farm or industrial site operations. The development of a biogas or RNG service industry in Alberta could take advantage of existing skillsets and current unemployment rates, particularly within the conventional Alberta energy industry.

However, the independent financial sustainability of AD business is not guaranteed in Alberta. As discussed in the *Challenges* and *Case Studies* sections, securing capital financing, feedstock agreements, regulatory permits, and earning a consistent electricity price in Alberta proves challenging. Financial incentives in Europe, however, are substantial enough to motivate producers to overcome these barriers (Canadian Gas Association, 2014).

Given the unique market circumstances in Alberta, with a deregulated electricity market that is currently experiencing decade-low electricity prices, and the competing options for organic waste disposal, financial sustainability in Alberta is arguably non-existent at the time of writing. The following section explores many measures that could be applied in Alberta with indirect or direct benefits to the AD business model and Alberta's overall sustainability.

Challenges Facing the Biogas Industry

Challenges Facing the Biogas Industry Globally

On a global scale, there are a number of common challenges to the biogas industry. Chief among them is financing and costs, both in terms of capital costs and operational costs, compared to conventional fossil fuel industries. The availability of capital investment funding, and the economic feasibility of a project, are often related to energy policy, regulation and related markets. Competition with established fossil fuels for energy market and infrastructure access, and competition with other renewable energy technologies, such as solar and wind, for funding and renewable premium payments, further hinders successful biogas industry development. In Europe and the U.S., it is well documented that the energy production value of a biogas plant alone will not give sufficient economic returns (United States Government, 2014) (Informa Economics, 2013) (AEBIOM, 2009). The lack of economic value given to environmental benefits and non-energy products of AD processing does not allow biogas operators to achieve the full economic potential of their operation. Table 7 lists some common challenges to the global biogas industry.

Table 7: Common Challenges Faced by the Biogas Industry

Challenge	Explanation
Competition with Fossil Fuels for Market Access	• Market strategies and capital investment funds that aim to increase the competitiveness of biogas with fossil fuels, such as feed-in-tariffs, tax incentives and RECs, are often too short-term to allow a project to achieve a return on investment (AEBIOM, 2009) (TEC Edmonton, 2015). • There is currently a lack of direct premium pricing options for domestic consumer purchase of low carbon energy, without AESO involvement, such as the example set by FortisBC in the optional purchase of renewable natural gas (Canadian Gas Association, 2014). • Competition with infrastructure, particularly connection fees and standards for natural gas and electricity grid connection. Transportation costs of the bulky feedstocks and digestate associated with biogas production, must compete with fossil fuels that are often transported more efficiently via pipelines (oil and gas) or rail (coal). • Use of RNG as a transportation fuel is limited by connection to the delivery and vending infrastructure and competition with conventional fuels; currently CNG is only feasible for large 'return-to-base' fleets.
Competition with other alternative energy technologies	• As a result of increased wind and solar capacity on the grid, power price agreement values for renewable energy are decreasing (Roberts, 2016). This has led to the ongoing operation of digesters becoming uneconomical and the decommissioning of on-farm digesters in some US states. • The intermittent and non-dispatchable nature of solar and wind technologies, and the relative benefits of reliable baseload and dispatchable electricity supply from biogas generation, are not currently valued by the structure of the existing electricity market.
Added-value benefits of AD are not fully recognised	• GHG offsets and nutrient management programs (if they exist) do not amply recognise the benefits of AD as a waste management system (United States Government, 2014) (AEBIOM, 2009).
Value of non-energy products not fully realised	• Often regulations are obstructive to the widespread use of non-energy AD products, such as specifications on fertilizer feedstock sources (AEBIOM, 2009). • A lack of research and development in non-energy AD products restricts the expansion of a biorefinery value chain to encourage start-up companies. The San Francisco based Mango Materials start-up, which produces a naturally occurring biopolymer from biogas, is a good example of how research and development funding can encourage such enterprise (Mango Materials, 2016). • Creation of large markets for these products is hindered due to a lack of regulation regarding classification and quality control of products, and development of best management practices for their use (United States Government, 2014) (AEBIOM, 2009).

Challenge	Explanation
Lack of public understanding, confidence and education on biogas processes and products	• Misconceptions about odours, transport, waste handling, pollution, safety, emissions and pathogen risks can impact the permitting process during project development, and consumer uptake of biogas products (Li, 2015) (AEBIOM, 2009) (United States Government, 2014). • As an example, Lethbridge Biogas met public opposition due to concerns over safety, odour and traffic. Concerns developed due to the measures the plant took to address air and water pollution risks (O'Brien, 2007).
Construction and permitting for new biogas facilities	• Inconsistencies between authorities within the same jurisdiction a common issue and a significant barrier in many jurisdictions (AEBIOM, 2009) (TEC Edmonton, 2015) (United States Government, 2014). • Lengthy and complicated permitting processes add capital costs to biogas projects and delay financial returns, reducing confidence from private investors.
Economies of scale and low energy value of feedstocks	• Fuel transport costs are high relative to energy outputs; operators can have difficulty consolidating sufficient volumes of feedstock (Ghafoori, 2007) (Canadian Gas Association, 2014) (TEC Edmonton, 2015).
Technological challenges	• Technological challenges are mostly concerned with nutrient processing and refining biogas production from specific feedstocks (TEC Edmonton, 2015) (AEBIOM, 2009) (Canadian Gas Association, 2014). • Processing of biogas to a high-quality RNG product is generally only available to large biogas operations due to equipment design size (Canadian Gas Association, 2014).

Challenges to Entry to the Alberta Biogas Market

Challenges to energy market access for biogas producers in Alberta are analogous to those found in many jurisdictions globally. Uncertainty, whether technical, financial, or regulatory, is a major barrier to investment. Biogas facility proponents must address uncertainty, but where technical risks for new and innovative technologies (including biogas and other types of renewable energy) can only be reduced to a point, then reducing financial and regulatory risks can be critical for stimulating investment (USDA, 2014).

As a fully privatized energy market, there are challenges that are specific to Alberta. The key issue is that the majority of electricity produced by the biogas operators has to compete with established, low cost, high-carbon-fuel based providers in an open market where the market share goes to the lowest bidders (Alberta Bioenergy Producers Group, 2015). For reference, the price of electricity production from biogas is estimated at $80-150/MWh compared to a current pool price of $15-25/MWh (Alberta Bioenergy Producers Group, 2016) (Olateju, 2015) (AESO, 2016). Pool prices do not take into account the added benefits of electricity generation from biogas, but instead reward only the lowest-cost supply from a purely energy-centric viewpoint. Volatility within the market compounds the issue through substantially increasing the risk to investors who cannot establish a confident return on investment. Without an assured minimum income, investors are unlikely to finance a biogas project.

The majority of biogas producers are expected to be net exporters of electricity with a capacity between 0.1-5MW. A net exporter of electricity of this capacity does not qualify as a micro-generator, but instead as a distributed generator. A distributed generator does not receive preferential market access, despite renewable attributes, but receives the pool price for the electricity exported to the grid, and therefore is subject to the associated price volatility. The recent announcement of a utility-scale REP applied only to generators with >5MW capacity and therefore does not provide a market access solution for generators exporting electricity with a capacity <5MW. As a distributed generator, the biogas operator is also responsible for grid connection costs, metering costs, and registration with AESO to become a pool participant (Alberta Utilities Commission, 2013). These costs are applied to all distributed generators regardless of plant capacity.

The AUC reviewed and attempted to streamline the process of connection for small generators connecting to the electricity grid in June 2013 (Alberta Utilities Commission, 2013). The application for small power plants less than 1MW who export to the grid, “can be effectively eliminated provided the owner of the power plant satisfies certain public interest requirements” (Alberta Utilities Commission, 2013, p. 1). Those interests are that no person is directly and adversely affected; the power plant complies with noise control regulations, and there is no effect on the environment. This is tremendous progress addressing one of the permitting steps for small distributed generation projects; however, it is likely that many new biogas facilities would exceed 1MW of generation capacity, and thus proponents must comply with AUC Rule 007 and must submit a power plant application. The costs and extended timeframes required to submit a full power plant application can be prohibitive to biogas developers.

Table 8 describes the key challenges to biogas developers entering the Alberta market.

Table 8: Challenges to Entry to the Alberta Biogas Market

Challenge	Explanation
Energy Market Volatility	• Market volatility reduces investor confidence and makes it difficult to calculate rate of return for a biogas project investment. • Without guaranteed long-term financial incentives for power production, risk will remain too high to allow significant private investment in biogas projects. • Without the Bioenergy Producer Credit Program (BPCP) which expired in March, 2016, there are no financial incentives that enable low carbon biogas producers to compete with fossil fuel energy producers in the privatised energy market (Alberta Bioenergy Producers Group, 2015). The current Bioenergy Producer Program will provide temporary transitional support until September, 2017 (Alberta Environment and Parks, 2016). Longer-term financial stability for the industry is yet to materialise, making private investment unfeasible.
Infrastructure and Supply Chain Competition with High-Carbon Energy Producers	• High-carbon energy producers have benefitted from provincial and federal grants, and tax incentives to build robust supply chains and infrastructure to dominate the market (Alberta Bioenergy Producers Group, 2015). Infrastructure investment for Alberta biogas production is lacking in comparison (Michalski, 2016). • Lack of availability, awareness and cost are significant barriers to widespread adoption of RNG (Canadian Gas Association, 2014). If RNG were to become more widely available and competitive with natural gas, it is likely that consumer awareness and demand would also increase (Canadian Biogas Association, 2016). • RNG production could be highest during times of low demand; competition from fossil fuel sourced natural gas could result in RNG not being accepted by the grid to maintain safety standards, particularly in rural areas that typically have smaller grid capacity (Canadian Gas Association, 2014).
Connection to Energy Supply Infrastructure	• Connection of an electricity-producing biogas plant, with a capacity greater than 1MW, to the Alberta electrical grid can be a costly and lengthy process (Olateju, 2015). • Operators cannot avoid these costs if electricity is being exported off their property; there are no 'across the fence' opportunities without AESO involvement (Alberta Bioenergy Producers Group, 2016). This is due to electricity exporters of any size being classified as distributed generators, and are not encompassed in the *Micro Generation Regulation* (Province of Alberta, 2008). • RNG projects must consider the costs of pipeline connection and contracts for capacity management when exporting to the natural gas grid (Canadian Gas Association, 2014).
Regional Differences	• Regional differences in expertise (companies), terminology and quality management are also significant barriers to successful implementation and connection of RNG operations (Canadian Gas Association, 2014).

Challenge	Explanation
Lack of Awareness and/or Experience of Feedstock Suppliers	• Feedstock suppliers are not likely to commit to providing feedstock prior to plant construction and proof of operation, and may need convincing that this is a worthwhile use for their waste; manure is important to farmers as a fertiliser and there can be competition for waste organics from other industries. Without feedstock contracts prior to plant operation, biogas investors may be unwilling to invest. • If the additional costs of feedstock or digestate transport are passed on to the farmer, the use of agricultural feedstocks for off-farm biogas production are even less appealing (Bell, An Organic Waste Inventory for Alberta's Agrifood Sector, 2015). Costs of energy production are often high for small plant sizes due to relatively high capital costs, while costs of very large plants also begin to plateau due to higher transport costs of low energy feedstocks (Ghafoori, 2007). Evidence of AD as a beneficial process, and a financial incentive or improved fertiliser product is required to convince farmers that transport of manure off-farm is worthwhile.
Competition with low-carbon energy producers	• The new REP being implemented by AESO does not provide for most biogas operations. The lack of an REP specific to bioenergy, or to small renewable distributed generators generally, means that biogas operators cannot compete with other conventional or alternative technologies in the Alberta energy market. The Indexed REC pricing system also does not take into account for the value of the back-up capacity required to address the intermittency of solar and wind technologies, and likewise does not recognise the potential of biogas to overcome these shortfalls.

Regulatory Challenges in Alberta

The nature of biogas projects as both a waste management operation and a power plant creates some complexity within the regulatory environment and permitting system in Alberta. The process can be a complicated, interlinked and potentially lengthy process (Michalski, 2016) (Alberta Bioenergy Producers Group, 2015) (Olateju, 2015).

To gain the necessary permits to begin construction of an AD facility, a developer must consult a number of agencies at the municipal and provincial levels, as shown in **Error! Reference source not found.**. Public consultation is an important part of the permitting process, but can lead to delays due to public misperceptions related to concerns about the odors from a biogas plant, transportation and handling of organic waste, and the possibility of pollution resulting from the use of digestate.

With a clear, biogas-specific permitting framework, and knowledge transfer to applicants, biogas developers would be better positioned to:

1. Determine optimal plant and storage locations and operational procedures that will result in the least regulatory burden. For example, siting plants located away from urban centres and environmentally sensitive receptors results in fewer regulatory requirements.
2. Submit stronger, more complete applications with the appropriate timing for public consultations and assessments resulting in faster permitting timelines.

The designation of a biogas plant is determined by the electrical capacity and the nature of the feedstock (see ***Error! Reference source not found.***). Designation as an agricultural operation is regulated under the Agricultural Operation Practices Act (AOPA), under the jurisdiction of the NRCB; designation as a waste management facility is regulated by the Environmental Protection Enhancement Act (EPEA) under the jurisdiction of AEP. The approval process differs between acts, which adds some complexity. However, both processes require public and stakeholder consultation, with the opportunity for stakeholders to submit a 'Statement of Concern' that must be addressed by the developer.

Regulation of the digestate material also depends on the plant designation. Under the AOPA, a plant utilising only on-farm feedstocks can land apply digestate in the same manner as untreated manure, since digestate meets the AOPA standards and administration regulations. If the plant is designated as a waste management facility under EPEA, the land application of digestate will require AEP involvement.

Legislative Gap

The AOPA requires storage of manure until a time when land application will have the least risk to the environment and largest potential for crop utilisation of nutrients. While the AOPA deals with the storage of manure for land application, it does not deal with on-farm mixed-source (third party) waste storage and spreading. In order to store and land apply mixed-source (third party) waste on-farm, an EPEA approval is required. This presents a challenge to biogas operators who have digestate available, and to

farmers wishing to adhere to AOPA regulations. The on-farm storage of digestate from mixed-source (third party) feedstocks is a regulatory gap.

To address the issue, the NRCB, AEP and Alberta Agriculture and Forestry entered into a "Memorandum of Understanding" (MOU). The MOU allows digestate containing a minimum of 50% manure feedstock to be stored in AOPA approved on-farm facilities, and spread to cropland under the AOPA regulations, regulated by the NRCB. The MOU is a good example of inter-departmental coordination to provide a medium-term solution to a regulatory gap. However, a modification to the regulations in AOPA and EPEA to specifically deal with on-farm storage of digestate will be required to provide a robust, long-term solution.

Power Plant Application and Grid Connection

The proponent of a plant that is exporting electricity to the grid must also submit a small (<10MW capacity) or full (>10MW capacity) power plant application to the Alberta Utilities Commission (AUC) who make a public interest decision. The small power plant application is a streamlined version of the full power plant application that requires the developer to prove the project will not adversely affect any person or the environment, and includes stakeholder consultation, proof of AEP application, noise impact assessment and environmental evaluation (involving a qualified consultant) (AUC, 2008). The approval process for AUC includes a number of parallel consultations and assessments also required for NRCB and AEP regulatory approval; biogas developers may not be aware which assessments or consultations lie with each organisation. Additionally, AEP approval requires confirmation of AUC approval; the process for permitting power plants is not formalised between the organisations. The challenge is in individual notices and processes, with similar assessments which add further costs to the developer. The interlinked nature of the permitting process also means that delays from one organisation can delay the whole permitting process. A Joint Notice process between the two agencies has been utilised on other non-AD projects. This presents a great opportunity for streamlining public notice but would require formal agreement and increased coordination between agencies.

Similar to the AUC, the AESO application process to register as a pool participant has been streamlined for 'small distribution generators' with a capacity of less that 5MW. The application does not require a 'System Access Service Request' (SASR), which is a lengthy process. Instead, the AESO processing time for an application from a new pool participant is approximately one month. While the application itself is not a significant barrier, it does require the developer to contact another organisation, adding to the complexity of the whole process.

Costs of connection to the grid are set by the Wire Service Provider (WSP), and the location of the project determines the WSP. Cost of connection can be inhibitive to smaller operations, and varies with time and location but does not always vary between large and small capacity connections. Timelines for connection also differ temporally and between WSPs; delays in connection can be inhibitive to small operations without sufficient working capital. However, it appears that connection costs cannot be altered significantly due to the safety and grid protection requirements of connecting a power plant to the grid.

It should also be noted that for biogas operators who do not plan to export electricity but intend to use the power generated on-site, certain regulatory requirements described here are not necessary. Specifically, the AUC power plant application and AESO pool registration are not required. Instead, if the plant has a capacity <5MW, it would be deemed a micro-generator and regulated by the micro-generation regulation; a much simpler process where the proponent deals with the WSP to connect to the grid and earn an electricity credit.

To date, a clear regulatory pathway for biogas plants, and digestate storage and spreading, does not exist. In the past applicants have lacked regulatory guidance, and applications have lacked sufficient information. Complications have arisen with mid-stream changes in plant design and scope, and consequently, application timeframes have been particularly lengthy. The experience that has been gained from past and present biogas industry applicants means that future projects are less likely to incur the same delays. However, without a clear pathway for all regulators (AUC, AEP, NRCB, municipality and so on), some potential remains for future applicants to experience challenges.

Table 9 describes the key regulatory challenges facing the Alberta Biogas Industry, and recognised reasons for them.

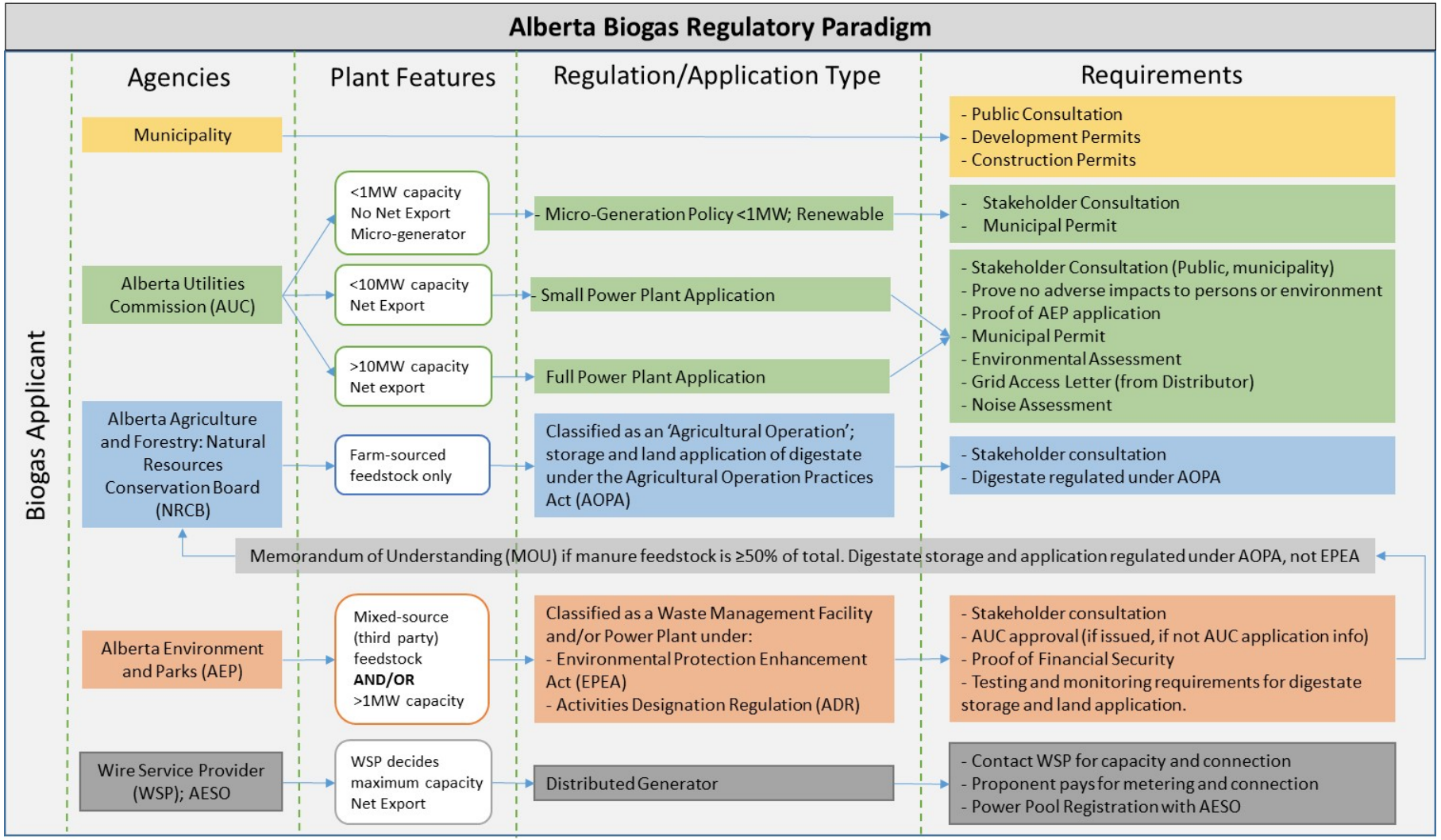


Figure 1: Alberta Biogas Regulatory Paradigm

Table 9: Regulatory Challenges Facing the Alberta Biogas Industry

Challenge	Description	Specific Issues
Timescales involved with obtaining permits and permissions	• A survey of industry stakeholders from small and large generators in Alberta deduced that, "the regulatory process from start to issuance of the required permits (four in total) will take a minimum of three years" (TEC Edmonton, 2015). However, these timescales are based on the initial few biogas projects in Alberta and may not be completely accurate for future projects. • Agencies carry out analogous consultations and assessments that could be avoided with efficient communication. For example, AUC, AEP, and the municipality each perform separate stakeholder consultations which adds unnecessary costs and delays to the project. • Incomplete applications or those that need significant alterations due to 'statements of concern' or changes in project scope, can add significant delays to approvals. Lengthy delays are particularly detrimental to biogas developers trying to raise private capital; investors need to gain return on investment as quickly as possible and are unlikely to invest in a biogas project until grant funds and regulatory approvals are confirmed. • Many grant funding opportunities available to biogas developers require regulatory approval prior to the release of funds. Applications are prepared in haste in order to obtain funds. The poor-quality applications can result in lengthy delays in approval issuance.	• Lack of a specific biogas regulatory framework for both regulators and proponents. • Lack of coordination between agencies such as the AUC, AEP or NRCB, and the municipality, causes replication of consultations and similar assessments. • Lack of a formal working agreement between agencies (particularly AEP and AUC) can result in overlapping assessments and potential duplication of efforts. • Distribution/transmission connection audits and other assessments are completed on individual agency timelines and conditions, rather than those required by the biogas project (TEC Edmonton, 2015). • Knowledge gleaned from past and current projects should be leveraged to improve efficiencies and consistency.
Availability of information to the proponent	• Lack of a clear outline of the regulations and policies applicable to biogas projects can lead to project development in sub-optimal locations and incomplete or deficient applications. This can incur delays and decrease investor and proponent confidence in the regulatory system. • Without clear knowledge of the permitting system in relation to digestate use, developers cannot effectively plan AD operations with respect to feedstock sources and digestate disposal. • Without a clear regulatory pathway for proponents the permitting process is complex and requires significant time investment and learning. This is a	• The current regulatory framework is too complex for most biogas proponents and investors to spend time learning about. • Lack of a clear permitting pathway for proponents to follow. • Lack of an information document specific to biogas operations outlining the relevant regulations and policies to better inform proponent decisions.

Challenge	Description	Specific Issues
	significant barrier to proponents who are adding a biogas operation to an existing operation.	
Financial value of low-carbon energy	• Current energy policies and regulations do not provide many benefits for small generators who export electricity to the grid. Despite an increase to the maximum capacity (5MW), the micro-generation regulation does not apply to most electricity-producing biogas operations since they are usually net exporters of electricity to the grid (Province of Alberta, 2016). Biogas plants therefore compete with large-scale utility projects in the open market and receive the pool price dictated by them. • Additional revenue streams to incent renewable electricity generation, such as the Bioenergy Producer Credit Program (BPCP), are short-term in scope and do not cultivate a sustainable biogas industry.	• Government incentives such as the BPCP are short-term and do not cultivate a sustainable biogas industry. • Biogas plants exporting electricity to the grid compete in the open market and receive the pool price set by utility-scale power plants. • Lack of regulation or policy to incent small distributed generators using renewable technology to export electricity to the grid.
Regulations around non-energy AD products	• A key use of digestate is land application as a fertiliser, utilising the benefits of significantly reduced pathogen content and improved nutrient and odour control. • Manure and digestate from only farm waste feedstocks can be applied under the AOPA regulations, enforced by the NRCB, with which farmers are knowledgeable and understand. • Storage and land application of digestate from mixed-source (third party) feedstocks requires AEP involvement which can make farmers nervous about involving AD in their operations, as an alternative to untreated manure. • To address this issue, the NRCB, AAF and AEP entered into an MOU that provides the NRCB regulatory authority for the on-farm storage and spreading of digestate derived from feedstocks containing at least 50% manure. This is an effective medium-term solution but regulatory modification will be required in the long-term. • The sale of non-energy products provides an additional revenue stream for biogas operators to supplement income from energy sales.	• The MOU addresses mixed-source (min. 50% manure) digestate storage and handling in the short- to medium-term, but a regulatory gap still exists. • A lack of quality standards developed around digestate impedes development of markets for these products both within and outside of the agricultural industry. • Better recognition needs to be given to types of feedstocks and products, and the reduced pathogenic, waste management and odour benefits of AD. • The regulatory body responsible for assessment is determined based on feedstock source and quantity, and designation as a waste treatment facility or agricultural operation. Without a specific biogas permitting framework, the process can be confusing and frustrating for applicants.

Challenge	Description	Specific Issues
	• There are no industry standards for digestate quality in Alberta. This reduces its' marketability to both farmers and other potential markets such as fibre products like 'Magic Dirt' (Magic Dirt, 2016).	
Competition with landfill	• Landfilling is relatively cheap with Alberta tipping fees averaging $71.30 per tonne (TEC Edmonton, 2015). • It is argued that the price of landfilling organic waste does not reflect the full environmental or financial cost of organic waste disposal. • There are few restrictions on the disposal of organic wastes in landfill (Canadian Gas Association, 2014).	• There are few incentives to waste producers to send organic wastes to AD rather than landfill. • A regulation, tax or ban on landfilling organics would incent the use of AD as a waste management process (Alberta Bioenergy Producers Group, 2015).
Full GHG avoidance benefits	• While biogas operators who export electricity to the grid can earn offset credits from offsetting grid electricity, other avoided GHG emissions are not currently recognised. • Avoided methane emissions from manure both upstream and downstream of the biogas operation, from storage and land application of digestate, are not recognised by an offset protocol. Offsets generated from such a protocol would be a significant revenue source for biogas operators.	• Lack of GHG offset protocols or policies that adequately address all the environmental benefits of AD, particularly avoided methane emissions (TEC Edmonton, 2015).
Connection Costs	• Connection costs are set by the WSP and differ between companies and temporally. High connection costs can be inhibitive, especially to smaller operations. • Delays in connection to the grid add further barriers to small operations that may not have sufficient working capital. • Connection costs are not directly correlated with the electrical capacity of a power plant, but may be unavoidable due to the necessary safety and grid protection requirements of power plant connection.	• High connection costs and potential delays in connection can be inhibitive, especially to smaller operations.

Realistic Approach for Alberta

Solutions Made in Alberta

The context in the section above informs the presentation of a realistic approach for Alberta to support a growing biogas industry. This section addresses solutions in seven parts; it is important to recognize that all parts are mutually supporting. Policy makers and regulators should endeavor to:

- Use the recent REP suggested by the AESO as a model for an analogous program for biogas and/or small generators to enable market access;
- Address and minimize uncertainty of energy prices and capital costs;
- Streamline the process of permitting a biogas facility;
- Simplify policies relating to the use or future processing of digestate;
- Open the door for the use of biogas as RNG; and,
- Open the door for the use of biogas as a transportation fuel.

Solution 1: Enabling Electricity Market Access for Small Generators in Alberta

Examples of successful biogas industries are located in jurisdictions that have allowed projects to access the electricity grid, and provided for a consistent and fair price of electricity. These two factors will be discussed independently from one another with respect to this solution, for a biogas plant exporting electricity to the grid.

Market Access

It is expected that the majority of new biogas plants in Alberta will be large enough to export electricity to the grid and won't use all the electricity produced on-site. Gaining access to the Alberta electricity grid system is a costly and potentially lengthy process with priority assigned on a "first-come, first served" basis. Current regulations do not provide preferential access for net exporters of low-carbon electricity with a capacity greater than 1MW. The costs and complexity associated with grid connection, combined with the volatility associated with revenue from electricity sales on a deregulated market, can mean that grid connection is cost-prohibitive for smaller operations.

The Government of Alberta has announced their intention to increase the share of renewable electricity generating capacity in the Alberta grid, with an aim of 30% renewable generation by 2030. As many changes to renewable electricity incentives are soon to be announced, **now is a great opportunity to both improve the process of electricity grid access, and to additionally consider prioritizing access for renewable and low-carbon alternative electricity generators.**

The grid connection cost and process are generally carried out by the WSP, and overseen by the AUC. Connection costs are influenced by the WSP, local infrastructure, and relevant safety and grid protection requirements. While the costs due to safety and grid protection requirements cannot be avoided, and the WSP is determined by project location, biogas developers may be able to choose to situate plants close to existing infrastructure. Investment in rural infrastructure development could also expand the number

of viable locations for biogas plants. The provision of funding to subsidise connection costs of small distributed generators (0.1MW – 5MW), especially those who exhibit renewable attributes, would enable more biogas operations to export renewable electricity to the grid.

The small power plant designation by AUC has gone some way towards lightening the application burden for small developers. The recent capacity increase in the *Micro Generation Regulation* to include plants up to 5MW capacity will enable easier connection only for small, industry- or agriculture-based plants who intend to produce electricity solely for their own on-site use. While further modification to the *Micro Generation Regulation* to include operations exporting electricity to the grid is not feasible, some elements of the regulation could be applied to improve the viability of biogas operations, including prioritised market access, and reduced metering and infrastructure costs (Alberta Utilities Commission, 2013).

Market Price

The deregulated Alberta electricity market is unique in Canada; the generation, transmission, and distribution functions are unbundled. AESO exists under the provisions of the *Electric Utilities Act* and operates a spot market for electricity. The price of wholesale electricity in this spot market fluctuates hourly in Alberta, and can experience substantial peaks and troughs depending on demand.

At the time of writing, the average spot price of electricity in year 2016 (January to October) was $17.55/MWh, or less than 2¢/kWh. There are currently no biogas operations in Alberta that qualify under the *Micro-generation Regulation*. Those plants currently in operation are net exporters of electricity and are therefore considered distributed generators who earn the spot price for electricity grid exports. The continuity of low electricity prices has created a situation where some biogas facilities have operating costs in excess of their revenue (see *Case Studies*).

Markets around the world that have seen the greatest uptake of biogas facilities (and other renewable energy technologies) have some form of consistent pricing for the renewable electricity that is produced. The most commonly cited example of a successful market uptake of biogas is Germany. Biogas already provides more than 5% of total electricity demand, and is increasing from 2.5 GW of capacity in 2010 to 3.8 GW of capacity by 2020 (AEBIOM, 2012). German biogas facilities still rely on financial support to be competitive with fossil fuels. In 2000 the German government introduced the *Renewable Energies Law* 2000 (EEG) to support profitable operation of renewable electricity facilities with a feed-in-tariff (FiT). The FiT and EEG required utility companies to:

a. Connect renewable projects to the grid;
b. Give priority to renewable energy sources on the grid;
c. Compensate the renewable projects with the rates prescribed by the FiT; and,
d. Recognize the biogas power benefits beyond only electricity production (e.g. job creation, stable base load and ancillary environmental benefits).

The system allows utility companies to pass on the additional costs to consumers negating financial support from the government. The German example is a good model for Alberta since the German electricity market is also deregulated. In 2011-2012, the average spot-price of electricity was €50 – 55/MWh, while the average extra cost of bio-based electricity was €128/MWh. The feed-in-tariffs for biogas ranged between €60 – 250/MWh (AEBIOM, 2012).

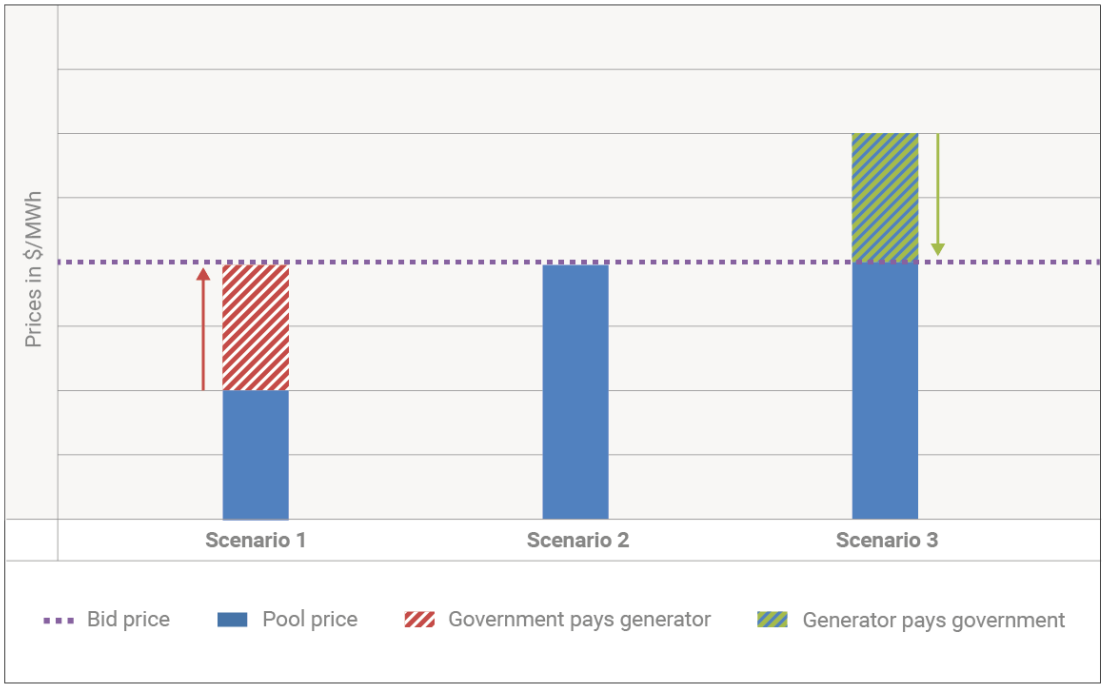
Other jurisdictions that have seen good uptake of biogas technology include Italy, the UK, and Sweden. In Italy, renewable electricity is promoted through a quota system of *Green Certificates*, where all electricity companies must either generate or purchase a certain number of certificates in a given year (AEBIOM, 2012). Similarly, in the UK, the volume of electricity is incented through a form of trade certificates while producers of renewable electricity earn a feed-in-tariff. A renewable electricity quota system (and resulting certificate trading system) is an important mechanism for stimulating renewable electricity in Sweden, although Sweden additionally employs a tax and a grant system.

The current spot price of electricity has been described by some as "unsustainably low" in Alberta, and the forecast does not show a substantial increase in the spot price in the coming few years. **If Alberta is to reach the stated goals of installed renewable energy capacity, including biogas, then there must be some form of financial incentive for electricity producers.**

The Government of Alberta (GoA) has recently accepted recommendations from the AESO to implement two major changes to the Alberta electricity market:

1. Implement a capacity market system that allows generators to compete (in an auction) for payments to maintain the capacity to produce electricity on demand, as well as the electricity they sell to the grid. The transition is expected to be in place by 2021.
2. Implement a capacity purchase agreement in the form of a Renewable Electricity Program (REP). The program utilises an indexed Renewable Energy Credit system (Indexed REC) to guarantee new investors in renewable electricity generation projects a fixed price of electricity, based on the proposed cost of that electricity. Competition between developers is created through an auction process where viable projects bid a price for the electricity they will sell to the grid for 20 years, and contracts are won by the lowest bidders. The GoA will pay the developer the difference between the pool price and the bid price, thus reducing investment risk and encouraging competitive renewable electricity generation (see **Error! Reference source not found.**).

Indexed Renewable Energy Credit



Scenario 1

The pool price is low, so the government payment to generators (red) is needed to meet the bid price.

Scenario 2

The pool price is equivalent to the bid price, so the government would issue no payment to the generator.

Scenario 3

The pool price is higher than the bid price, so the generator would be paying that amount (shown in green) back to the government.

Figure 2: Indexed REC System (AESO, 2016)

The capacity market may provide some additional revenue for Alberta biogas operators through payments for the on-demand capacity that biogas plants can provide. The system will incent biogas electricity production for its' dispatchability and recognise this benefit over other renewable technologies. The system is in the early stages of development and details are therefore limited, but it seems likely that biogas operators will have to compete in this system with conventional fuels such as natural gas. Priority access for capacity payments for electricity generated using renewable fuels would negate competition with conventional fuels in an auction-style competition, and should be seriously considered by decision-makers during capacity market development.

The Renewable Electricity Program (REP) is a significant development for utility-scale (>5MW) renewable electricity generation projects in Alberta. However, the 5MW capacity lower limit is likely to exclude many

biogas projects that tend to range from <100KW to several MW in capacity. Indeed, there is a gap in market regulations and programs for renewable electricity generators exporting to the grid with a plant capacity <5MW. The fuel neutral competitive aspect of the REP may also exclude biogas projects by selecting projects that produce renewable electricity for the lowest cost; recent figures suggest that the AESO break-even prices for wind and solar generation could be too high (AESO, 2016) (Roberts, 2016).

The auction process also presents a number of other issues including:

- High costs and complexity associated with auction participation, development of a bid package, and transaction costs could be inhibitive, especially to smaller operations or individuals.
- Forced timing of projects to participate in the same auction process and obligations to have the plant constructed and producing electricity by a specific date. This would inflict pressure on the few biogas consulting and construction resources currently operating in the province, and would likely reduce competition and project success.
- A potential lack of competition within the auction could lead to excessively high electricity prices from this sector, which would have a negative impact on public perception.
- Selection for certain biogas operations over others, for example, market share could be taken by cheaper municipal landfill biogas operations and exclude farm-based operations.

Some of these difficulties could be overcome through aggregation of small biogas plants into a single project and thus a single auction bid. However the logistics of an aggregated project may prove to be preventative.

Despite the challenges, an Indexed REC system is, nevertheless, an attractive model as it allows competitive market access for renewable generators with conventional energy sources in an open market. It is unlikely that the GoA and AESO would make significant changes to allow for biogas projects in the recently proposed REP, but a carve-out of a similar Indexed REC system and program for either small renewable or specifically biogas generators, for example 0.1MW – 5MW capacity, could address the gap in regulation, and provide an effective solution to the market access and financial barriers faced by the Alberta biogas industry.

Due to the decreasing costs of wind and solar technologies, and smaller likelihood of construction of 0.1-5MW capacity solar and wind plants under the existing REP, the preferred option is an adapted version, or “Bio Carve-out”, of the REP, focusing on biogas electricity generation between 0.1-5MW capacity.

Bio Carve-Out REP

To overcome the challenges presented by an auction, a fixed ‘standing price’ system could be employed. Here the GoA would set a reasonable price for the electricity produced, based on research conducted on biogas technologies in Alberta. Project developers would apply to produce and sell electricity at this price which fixed and guaranteed for 20 years, and financed in the same way as an ‘Indexed REC’ (see Figure 2). The ‘standing price’ could be reviewed and reset (lowered) periodically to reflect or encourage

technological innovation, or as new incentives improve operator revenue streams. Different standing prices could be employed depending on the biogas technology or feedstocks being used. It would be important to fix a long-term standing price for each project to foster investor confidence, ensure investment return, and continued plant operation. A techno-economic modelling approach, such as the approach presented in this study, could be used to estimate a potential range of appropriate standing prices.

The standing price system would ensure a reasonable cost of biogas-generated electricity to the consumer, while potentially preventing selection of certain AD operations based on the lowest operating costs; this will rely on proper research for an effective 'standing price'.

The REP also fails to recognise the additional benefits of biogas production over alternative low-carbon producers, namely:

- Consistent, reliable and dispatchable energy generation (baseload capacity);
- The environmental benefits of agronomic nutrient stewardship, and agricultural greenhouse gas management;
- Environmentally preferable organic waste management solutions; and,
- Enhanced job creation relative to wind and solar; and rural economic diversification.

Some of these benefits could be credited through additional programs or policies, which would allow the GoA to incent the attributes of AD that are most important to the province, or be reflected in the standing price(s) set within a biogas-specific REP. The recognition of these benefits represents a cross-ministry challenge within the Government of Alberta.

A third option to create a market for biogas-produced electricity is to create a 'Renewable Portfolio Standard' (RPS), specifically for bioenergy. An RPS requires energy companies to include a proportion of the electricity they include in the grid to come from renewable sources, in this case bioenergy. The implementation of this regulation would put the onus on the energy industry to develop the resources and infrastructure to ensure compliance with the standard. For this reason, the initial proportion required by the standard would have to be reasonable to both create a seller's market for bioenergy projects, but also allow projects to develop and infrastructure to be built. The RPS would allow trading of 'Renewable (Bioenergy) Energy Credits' between energy companies to ensure compliance. The drawbacks of an RPS are that it would likely encourage a few large operations, rather than many smaller on-farm projects, and that biogas producers would still be somewhat exposed to regulatory and market risks, therefore reducing investor confidence.

It should also be noted that capital financing is an essential tool towards the development of a mature and self-sustaining biogas industry. Data collected from existing biogas plants in Alberta, and the results of the techno-economic models presented later in this report, show that capital grants from Emissions Reduction Alberta (formerly Climate Change and Emissions Management Corporation) and Alberta Climate Change Office (ACCO) bioenergy grant programs, for up to 50% of capital costs, have enabled

biogas developers to successfully construct and operate. Until the industry matures, and appropriate long-term financial incentives are in place, capital grants will be needed to attract sufficient interest and private investment, and support the initial growth of an Alberta biogas industry.

In summary, a stable, predictable, long-term, and accessible public investment program is essential to allow biogas facilities to compete in Alberta's current electricity market, and ensure sustained growth and innovation in this space. A 'Bio Carve-out' REP, using a 'standing price' system instead of an auction, could effectively attract investor capital and support a competitive and reasonably priced electricity market for biogas generators during an energy market transition (Alberta Bioenergy Producers Group, 2015).

Solution 2: Streamline the Process of Permitting a Biogas Facility

Previous studies of the Alberta biogas industry have highlighted regulatory challenges associated with obtaining the necessary permits for a biogas facility, most notably the *Biogas Market Study* (TEC Edmonton, 2015). In the past, the permitting process has taken three to five years and has been cited by industry insiders as a deterrent to other developers, especially those that do not have the resources to pursue such a lengthy process. However, in recent years progress has been made to improve the regulatory framework and manage some of the key triggers of these delays.

Regulatory challenges are not unique to Alberta. Indeed, similar challenges were encountered throughout the biogas industry's development in Europe. The 2009 policy recommendations at the EU level put forward by the European Biomass Association (AEBIOM, 2009) include such statements as:

> *"The excess of such non-technical barriers is a main obstacle to a quicker implementation to biogas plants in Europe"*

> *"[Obtaining] permits for new biogas plants is a long-lasting process in all member states. Regulations are too numerous and the public misperception[1] is the rule. Efforts should focus on communication and coordination between relevant administrative bodies for permits."*

Within the same discussion, Germany is held up as an example of a state that regulates access to electricity and gas grids to ensure priority access for renewable energy projects, including biogas. This has proven to be a market-stimulating force.

Similarly, Washington State gives an example of how a coordinated approach between agencies can help to remove some of the complexity and application burden from a biogas proponent. An application is

[1] Many public misperceptions are related to concerns about the odors from a biogas plant, transportation and handling of organic waste, and the possibility of pollution resulting from the use of digestate.

made to one of the lead agencies which then collaborates with other relevant agencies who in turn contact the applicant with requests for additional information if required (see *Case Study: Washington State*).

One of the single most important regulatory changes that would enhance the biogas industry in Alberta is to streamline and clarify the permitting process through the development of a biogas-specific permitting framework. The framework would be a documented, coordinated suite of decisions as to how AD facilities should be treated under the existing acts and regulations, with an accompanying guide or flow diagram to clarify expectations for biogas proponents. It is important that all biogas facilities are regulated equally to avoid the potential for accidents and/or damage of the industry's public image. The framework should be developed utilising the knowledge and experience of regulators, proponents and industry leaders within the province.

Clarifying the permitting process through the development of a biogas-specific framework would have a number of beneficial impacts on industry development:

1. Developers and investors would be able to better assess the regulatory risks associated with a project and make modifications to reduce risk.
2. Including a flow diagram or similar, which outlines requirements for approval and relevant agencies and contacts for a specific project type, would streamline the process and enable developers to better understand the permitting pathway for their project.
3. Detailed instructions on the information and consultations required for each application will enable developers to submit strong applications requiring fewer alterations, and therefore reduce delays in obtaining approval.
4. Definition of which agency is responsible for assessing and consulting on each aspect of the application will enable efficiencies to be made through combined assessments and consultations, and will reduce the complexity of the process as a whole.
5. A clearly laid out framework would reduce the potential for regional differences in the application of regulations based on inexperience with a new technology. The formation of cross-functional teams between regional regulators would also reduce the potential for regional inconsistencies.
6. Incorporation of industry standards and best practices in biogas facility design and operation, adapted from other jurisdictions and in consultation with Canadian and Albertan biogas industry leaders, would enhance the industry's health, safety and environmental standards, and consequently public image and investor confidence.
7. Estimated processing times will allow developers and investors to incorporate the permitting process in to the business plan with some accuracy.

The instigation of a **regulatory lead to shepherd the developer through the permitting process would also streamline the process**. The lead organisation could co-ordinate with other agencies for improved efficiency, as demonstrated by the Washington case study (see *Case Study: Washington State*). The lead should be unbiased to avoid selecting for projects that suit that particular agency's interests. It would be

inappropriate to comment on which, if any, agency is best suited to lead the process in this paper; collaboration between regulators would be required to determine if this is an appropriate pathway.

Inter-agency collaboration on permitting requirements and consultations would notably improve the efficiency of the permitting process, and build on the success of NRCB and AEP collaboration in the establishment of an MOU. In particular, it appears efficiencies can be gleaned through a closer and more formalised working relationship between the AUC and AEP. Presently, the proponent must apply separately to each organisation, with some overlap in the information required for each, and include the other organisation's full application for reference. Each organisation will then carry out their own public notice and stakeholder consultation process, and deal with stakeholder concerns separately. With no formal recognition of which concerns fall under the authority of which organisation, there is potential for replicated work. AEP must also wait for confirmation of AUC approval prior to issuing its' own approval.

A closer collaboration between these organisations, which combines public notice and stakeholder consultation, and outlines which organisation governs specific assessments or concerns, has the potential to reduce costs and timelines associated with project approval. There is also scope to include the municipality and WSP in the same process. Combining the applications of each organisation with submission to the just lead organisation would further reduce the cost to the applicant and help to prevent misunderstandings between the interested parties.

Solution 3: Simplification of Digestate Policy Measures

Addressing policies related to biogas digestate can go a long way towards supporting the operational logistics of a biogas facility, reducing operating expenses, and creating additional revenue streams for biogas facilities.

Digestates from biogas facilities are high in essential crop nutrients (nitrogen, phosphorous, some potassium, calcium and magnesium), while free of, or nearly free of, the pathogens that would be present in land-spreading of the same, undigested materials (Informa Economics, 2013). Presently, digestate in Alberta is not valued for its full suite of benefits, which include:

- Plant-accessible nutrient content;
- Significantly reduced pathogen content;
- Potential for reduced weed seed content;
- Elimination of specified risk materials and other organic wastes;
- Reduced GHG emissions; and,
- Cycling of nutrients that would otherwise be lost to the environment with associated consequences.

Policies affecting biogas digestate in other jurisdictions are often related to water quality or organic waste management. Updates to water or waste regulations in Alberta could recognize the environmental benefits of AD of organic wastes and residues. It is understood that the regulations regarding municipal sludge and wastewater are undergoing updates and consolidation at this time; digestate could be included and/or used as a model for beneficial uses of wastewater sludge in the updated regulations.

On-farm storage of digestate originating from on-farm feedstocks is regulated under the AOPA by NRCB in the same way as untreated manure; farmers understand the process and requirements. Without the current MOU, on-farm storage of digestate from mixed-source feedstocks is regulated under the EPEA by AEP; a process associated with waste management operations with which farmers are not familiar with, and could be uncomfortable being involved with. The MOU provides a means to allow digestate originating from listed mixed-source feedstocks, including at least 50% farm-based feedstocks, to store and apply digestate under the same conditions and regulations as untreated manure under the AOPA, regulated by NRCB.

The MOU is an effective medium-term solution and a strong example of inter-departmental coordination among AEP, AAF and NRCB. This coordinated approach could be developed further to create a longer-term protocol or Code of Practice specific to storage and land application of digestate material, taking into account the specific properties of the material. Such a protocol should be developed based on consultation with industry leaders and research from other jurisdictions, and include:

- Specified acceptable feedstocks based on contents of nutrients, heavy metals and other pollutants of concern;
- Process standards dependent on feedstocks, including pasteurisation step;
- Periodic digestate (tail-end) testing to ensure material is commensurate with specified criteria for land application; and,
- Quality standards for digestate.

Research on the effect of AD on reducing heavy metal content is both lacking and conflicting (PAMI, 2014). PAMI (2014) recommend that AD should be assumed to have no impact on heavy metal content, and so feedstock heavy metal content is indicative of the digestate properties. Assuming this is the case, heavy metals could be regulated or controlled through the categorisation and sampling of feedstocks. The province of Ontario provides a good example of how the regulations seek primarily to ensure that the material is not contaminated with heavy metals, employing a sampling and analysis protocol for maximum metal concentrations in feedstocks. Downstream testing of the digestate product is also feasible but would not allow operators to predict the properties of the digestate prior to digestion.

Pathogens and weed seeds can be effectively eliminated through regulation of the AD process, and should therefore be controlled through the development of downstream digestate standards. Pathogen reductions are achieved through longer storage periods, higher temperatures, and changes in conditions

such as pH (PAMI, 2014). EU law requires a pasteurisation step either pre- or post-digestion to eliminate pathogens and weed seeds in preparation for land application of digestate as a fertiliser (PAMI, 2014). Pasteurisation is often a necessary post-digestion step that involves heating the digestate to 70^{o}C for an hour, and has been proven to be economically and energy efficient (PAMI, 2014).

The province of Ontario categorises feedstocks based on the pathogenic and heavy metal risks, and specifies the AD conditions required to allow the safe application of digestate as fertiliser, through designation of the facility as a, "Regulated Mixed Anaerobic Digestion Facility" (RMADF) (see *Case Studies* section) (OMAFRA, 2016). To gain designation as an RMADF, limits are placed on the total quantities of feedstocks of different categories allowed per operation and a nutrient management strategy must be in place; up to 25% off-farm waste is allowed with RMADF designation, and up to 50% off-farm waste is allowed with an amended nutrient management plan which is assessed on an individual basis. Standards are also defined for feedstock and digestate storage facilities (OMAFRA, 2016).

Alberta could build upon the success of the MOU to develop a similar code of practice to regulate land application of digestate from mixed-source feedstock operations. In the review by PAMI (2014), it is recommended that digestate is treated as an agricultural waste when regulated through the classification of 'quality feedstocks', based on content of heavy metals, nutrients, organic pollutants and physical contaminants, and process standards to reduce pathogens of concern and weed seed contents. Periodic sampling of the feedstocks (especially if there are any upstream changes) and the digestate would be required to ensure a safe digestate product is being produced and used. However, categorisation of feedstocks and control of quantities would reduce complexity and potentially cost to the operator, increase flexibility for operators to accept certain feedstocks at short notice, and reduce the risk of producing unsuitable digestate. Implementation under the prescriptive AOPA would utilise the existing regulations and standards already familiar to farmers and currently enforced by the NRCB, reducing the need for storage container upgrades or similar.

The creation of quality standards for digestate will not only impact environmental protection and create a more transparent and simplified policy, but also increase consumer confidence in the product and potentially create new markets in industries such as fiber and horticulture (for example 'Magic Dirt'). This may result in a joint initiative between government and industry, where digestate regulations address the safety of the product, and industry creates quality standards, market interest and further research and development.

Solution 4: Develop RNG Market Access for Biogas Generators in Alberta

Bio-methane generated from a biogas facility can be combusted to generate electricity, or it can be cleaned to a high standard and injected into the natural gas grid, or stored as compressed or liquefied natural gas (CNG or LNG). In this manner, biogas facilities could contribute to the heating and transportation sectors, as well as the electricity sector.

Grid Access

Challenges for biogas producers to access the natural gas grid differ somewhat from the above discussion on electricity grid access, although parallels are present in a discussion of market support for biogas grid access.

Provincial natural gas grid regulations in Alberta fall under the jurisdiction of the AER. Since there are already numerous corporations that regularly inject and remove gas from the natural gas pipeline, there are clearly defined regulations and standards for doing so. The AER regulations to this end are likely geared towards larger organizations, and so the process may seem costly and onerous to a comparatively small biogas producer.

Technological challenges are possible since, to the knowledge of the authors, this type of natural gas injection has not yet been attempted in Alberta. Upgrading technologies have been developed and are continuing to develop in other jurisdictions, such as Germany where 160 biogas facilities upgrade to RNG and inject into the grid, and 177 biogas facilities upgrade to CNG for use as transport fuel (Bell, Trip Report - International Biogas Conference, 2015).

Some critical success factors that would enhance the uptake of biogas as renewable natural gas in Alberta are:

1. **Guaranteed or prioritized grid access for lower-GHG methane sources**, such as biogas, particularly in low pressure pipelines regulated by Alberta Agriculture and Forestry, Rural Utilities Agency.
2. **Clarifying connection standards** to ensure that the regulations are easy to interpret from a biogas producer standpoint. The quality of gas is of utmost importance for the safety and integrity of the natural gas system, and must be upheld, but also must be technology-agnostic and specify product standards and measurement standards.
3. **Funding research** into small-scale gas grind injection technology development and biogas to grid-standard RNG upgrading technology.
4. **Investment in rural natural gas grid infrastructure** to allow grid access for rural biogas producers.

Market Access

The current prices of natural gas in Alberta are at a decade-low, so although electricity prices are also low, the additional infrastructure costs for biogas upgrading and potential pipeline construction fees are prohibitive. It is therefore apparent that, similar to biogas-produced electricity, the recognition of

renewable attributes of RNG through modifications to the energy market may be necessary to see an increase in biogas-to-RNG products.

The Canadian federal government recently announced its' intention to adopt a national 'Clean Fuel Standard' (CFS), with the aim of achieving annual reductions of 30 megatonnes (Mt) by 2030 (Government of Canada, 2016) (Lane, 2016). The national CFS sets targets for the lifecycle carbon intensity of all fuels, including transport, residential and industrial fuels; natural gas is included in the national CFS. The intention to adopt a national CFS is a recent announcement with a discussion paper set to be published in February 2017, and stakeholder consultations and working groups to follow (Government of Canada, 2016). However, while an initial framework for the national CFS is expected soon, industry experts believe a significant development lag of up to 4-5 years could elapse before final implementation.

With this in mind, the GoA could look to implement a provincial CFS, or update the existing *Renewable Fuels Standard* (RFS), to include fuels produced from biogas, and to increase the requirement for proportion of blended renewable fuels year-on-year. The *Renewable and Low Carbon Fuel Requirements Regulation* (RLCFRR) in BC provides a good model for the development of a similar regulation in Alberta. The RLCFRR requires fuel suppliers to meet annual averages for renewable fuel content, allowing flexibility in fuel blends and location of sales within the province (Government of British Columbia, 2010). The inclusion of RINs, as developed by the US EPA and used in the California LCFS, would allow identification of the biofuel component, meaning it can be bought and sold to ensure suppliers meet their obligations (US Environmental Protection Agency, 2016). These frameworks provide an example of how RNG could be implemented into the conventional natural gas or transport fuel supplies.

The introduction of a provincial CFS could develop a large market for RNG production in Alberta as suppliers look for ways to reduce the carbon intensity of conventional fuels; blending lower carbon fuels with conventional fuels is one method suppliers can reduce the carbon intensity of their fuel. Due to the significant potential of RNG production in Alberta, the market could also extend beyond Alberta to other provinces when the national CFS is effected.

The development of a provincial CFS now would instigate the research, infrastructure and policy requirements to allow Alberta to benefit from the national CFS and capitalise on the potential national market when it comes into effect, in addition to improving Alberta's energy sustainability and the other added benefits of AD as discussed throughout this paper.

Solution 5: Avoided Methane Emissions Offset Protocol

The process of using organic wastes to produce biogas, and using the resulting digestate as a fertiliser, incurs a number of avoided GHG emissions when compared to the baseline scenario. These avoided emissions are accounted for under the current offset protocols in Alberta (Alberta Environment and Parks, 2016).

Presently, the "Quantification Protocol for the Anaerobic Decomposition of Agricultural Materials" includes avoided GHG emissions due to displacement of grid electricity, displacement of thermal energy production, and disposal of feedstocks by landfill and incineration (Alberta Environment, 2007). However, since the GHG benefits of biogas extend beyond electricity displacement to include avoided methane emissions (a topic of relative importance), these benefits should be captured by a modified anaerobic digestion protocol, and be eligible for offset generation. Specifically, avoided methane emissions due to reduced feedstock storage time, and land application and storage of digestate rather than untreated manure, or inorganic fertiliser, should be included. The inclusion of avoided emissions due to displaced grid electricity would also need to be revised if an REP such as the one suggested by AESO were introduced, since payments from the REP cover the renewable attributes of the electricity generated. As is normal with offset quantification protocols, best management practices would also be included to avoid fugitive emissions from biogas plants.

The province of Quebec and state of California both include offset protocols for avoided methane emissions from manure storage facilities (California Environmental Protection Agency: Air Resources Board, 2014) (Editeur Officiel du Quebec, 2016). While these protocols provide a useful framework for quantifying avoided methane emissions from upstream storage of manure, there has been some concern regarding the applicability of their methane generating potential factors to projects located in Alberta, given the effects of a different climate.

Additional research on avoided methane emissions from manure storage, and from use of digestate as a fertiliser, is critical to developing an effective revised anaerobic decomposition offset protocol. The additional offsets that are not currently accounted for have a significant potential to provide an additional and potentially large revenue source for biogas operators, and/or feedstock owners, while inducing further GHG reductions.

New agronomic initiatives may provide methodologies for quantifying the benefits of the use of digestate, such as the Nitrous Emission Reduction Protocol (NERP), that quantifies GHG emissions associated with the use of nutrient stewardship on-farm. Inclusion of digestate products in this and other initiatives, such as climate smart agriculture, and organic food certification schemes, may drive further interest in chemical fertilizer and peat moss alternatives and could be used for marketing purposes.

Complementary Policy Measures

Policy Measure 1: Towards Zero Waste in Alberta

Recent research in the province of Alberta has created an inventory of organic waste types, sources and quantities, and has determined that there are approximately 3.4 million tonnes of dry organic waste produced per year in Alberta (Bell, An Organic Waste Inventory for Alberta's Agrifood Sector, 2015). This research also determined that the majority of the waste surveyed is still considered a liability (waste producers must pay to have the waste hauled to a disposal facility), and that disposal fees vary greatly across the province; incentives to divert the waste from a landfill also vary. It is clear that there is an opportunity for Albertans to divert waste to another use, or pursue converting the waste to a higher value product.

Albertans have the title of the highest per-capita waste generators in Canada, producing 1,052 kg/person in 2010, approximately 40% of which is organics (Alberta Bioenergy Producers Group, 2016). The city of Edmonton has since created a Material Recovery Facility that separates organics for composting, recyclable materials for further processing, and converts other wastes into biofuel with the Enerkem waste-to-methanol technology. The City of Calgary has introduced an organic waste composting pilot program, which will be rolled out across the city by 2019, with all organics including paper and cardboard will be banned from landfills by 2018. Use of AD technology to manage such waste, instead of composting, has a number of benefits including reduced methane emissions, sale of energy and digestate products, and reduced odour issues, while the digestate product is more suitable for land application than compost. There are numerous rural municipalities whose waste handling facilities lag in sophistication, and there are many other diffuse sources of organic waste across agricultural and forestry centres in the province.

Small landfill fees are likely exasperating the issue. Currently, fees only consider operating costs and do not include greenhouse gas emissions, risks to soil and water quality, and land use change. AD of organic wastes is currently a more expensive waste management option with lower environmental impacts than landfilling. Expanding landfill fees to include environmental costs will improve the feasibility of AD as a waste management procedure opportunity.

Policies and programs that support reducing organic wastes from landfill provide many environmental benefits, and support biogas facilities through creating a feedstock stream well suited to anaerobic digestion. Biogas operators would also be able to charge tipping fees, particularly for industrial organic waste producers. The models in this paper show that charging tipping fees can be a very significant revenue source for biogas operators (*see Techno-Economic Models*). Some examples of policy measures towards zero waste in Alberta include:

1. Implement a landfill tax or levy, where the revenue from this levy will support organic diversion and energy recovery technologies, waste audits of industries, and industry-targeted waste diversion service offerings (Behrens & Sultana, 2014).
2. Use public funds to support the development of municipal-scale AD facilities, as is currently done in the province of Quebec (Canadian Gas Association, 2014). Depending on organic material collection policies and logistics, organic streams could create large quantities of compost that may

or may not get used. Instead, they could create smaller amounts of digestate (suitable for land application) and energy, while simultaneously meeting targets for local renewable energy generation.

3. Develop municipal landfill fees to reflect the total environmental footprint and true public cost, and extend the City of Calgary approach to ban landfilling of organics to the whole province.

Policy Measure 2: Recognizing Soil Health Through Nutrient Management

Alberta's large land base has allowed for the spreading of waste agricultural nutrients on agricultural land with minimal impact to ecology or water quality. However, risks from manure such as pathogens and other contaminants do exist, and thus an extensive land base is required to achieve a certain dilution of the materials (The Prasino Group, 2012).

The use of digester technology to manage agricultural-based waste products effectively produces a nutrient product that reduces acidification of soils, reduces contamination of groundwater, and reduces odors (Alberta Bioenergy Producers Group, 2015) (PAMI, 2014). The process of digestion creates a product with more homogenized nutrients and nitrogen in the NH_4+ form; this allows efficient nutrient uptake by plants. Due to the improved usability, approximately 30% fewer acres are required to apply digestate-derived fertiliser compared to untreated manure (Informa Economics, 2013).

Currently there are no policies in place to incent the use of digestate rather than spreading manure in Alberta. The development of a nutrient management policy could interact with a biogas permitting framework to incent the use of digestate instead of manure. Incentives should be targeted towards consumers using digestate as a biofertilizer, and potentially the feedstock suppliers.

Alternatively a nutrient transport incentive may be particularly effective to encourage the movement of nutrients from areas where they are in excess, to areas that are lacking, and ensure compliance with nutrient management plans. Maryland Department of Agriculture provides an example of a nutrient transport incentive that aims to transfer excess manure from a region of intensive poultry production along Chesapeake Bay, to other regions, and thus alleviate eutrophication issues in Chesapeake Bay (Nosowitz, 2015) (Maryland Department of Agriculture, 2017).

The Maryland program delivers cost-share assistance for the transport of excess manure from all livestock up to US$20 per tonne, to a maximum of US$15,000/season or US$30,000/year (Maryland Department of Agriculture, 2015). The incentive is available to livestock farmers with high soil phosphorus levels, or insufficient land base to land apply manure produced on-farm (Maryland Department of Agriculture, 2015). Manure must be transported a minimum distance from the source to an area with low soil nutrients, be analysed for nutrient levels prior to transport, and follow biosecurity measures before land application; approved alternative users of manure are also eligible to apply (Maryland Department of Agriculture, 2015). A free and voluntary "Manure Matching Service" connects farmers and potential users of their excess manure based on location, and nutrient and temporal requirements (Maryland Department of Agriculture, 2015).

The Maryland example draws similar parallels with Alberta regarding areas of intensive livestock production associated with high soil nutrient loading and potential risks to soil health, water quality and ecology. The incentive removes financial barriers to manure transport due its weight and bulk. Since digestate can be easily processed to separate solids and liquids, has a lower density, and is more easily applied as a biofertilizer compared to manure, a similar program for digestate transport in Alberta could be particularly effective and further encourage upstream and downstream farmers to participate.

Policy Measure 3: Transportation Fuel Options

Many vehicles can be converted to be powered by natural gas (in the form of compressed natural gas (CNG) or liquefied natural gas (LNG)) instead of diesel. Using RNG as a transport fuel, whether blended with natural gas or not, can substantially reduce GHG emissions when compared to conventional fuels (Canadian Gas Association, 2014). Natural gas is substantially cheaper than gasoline or diesel on an energy basis, hence there is increasing market interest for fuel switching.

The development of the market, however, is hindered by a number of compounding factors that are a common theme worldwide and in Alberta. The lack of refuelling infrastructure dissuades consumers and fleet owners from buying or converting their vehicles for natural gas use. At the same time, potential infrastructure investors are dissuaded from building CNG/LNG refuelling stations due to a lack of natural gas vehicles (NGVs) and hence demand. The lack of demand created due to a lack of infrastructure also decreases the demand for new or converted NGVs which are therefore not sold at competitive prices, further reducing consumer interest (Jegelevicius, 2016).

A report by the Green Gas Initiative states that, “government supported coordination and more information to the greater public are crucial” to overcoming these barriers (Neuland PR, 2016). Specifically, the authors suggest a number of fiscal instruments, such as tax rebates on the purchase of NGVs and fuel tax discounts; and regulatory tools such as priority access for NGVs in sensitive areas such as city centres, and development of maintenance and repair standards (Neuland PR, 2016).

The City of Calgary has begun to include NGVs into their transit fleet. These buses are cost-effective to run and provide the benefits of improved local urban air quality. The national CFS will also aid the development of low carbon transport fuels. However, the GoA will also need to play a part in creating a successful market for RNG transport fuel through:

1. Requirement for lower carbon fuels used by government agencies, municipalities, and public transport services.
2. Introduction of an interim provincial transportation fuel intensity target for CNG and LNG transport fuels, together with reduced fuel tax on low carbon fuels.
3. Introducing financial incentives for initial uptake of NGVs including tax rebates on new NGV purchases and older vehicle conversions.
4. Use public grant funding could support investment in refuelling infrastructure, or require fuel suppliers to include CNG/LNG refuelling points in a proportion of their refuelling stations.

Building a Supporting Service industry and Enhancing R&D Capacity

Existing biogas facilities in Alberta are relatively recent developments, and employ technology that is new to Alberta and Canada. Some experimental facilities in the province have failed, while others have successfully employed technologies and expertise from the biogas industry abroad. The UK biogas industry developed successfully with a strong influence from German engineering and expertise. As a result, homegrown biogas engineering expertise has suffered so that UK operations often employ German technicians for biogas service and repair. **An initial influx of foreign biogas expertise should give rise to a mature biogas industry in Alberta characterized by local engineering expertise, as well as a supporting service industry**. Supporting policy measures to develop these outcomes could include:

1. Creating funding envelopes within research, development, and innovation programs in Alberta and Canada to support the development of locally-appropriate technologies, and to develop local engineering expertise.
2. A public-private collaborative initiative to introduce knowledge relating to biogas facilities within trade schools and renewable energy skill-retraining programs.
3. Job creation incentives for rural jobs created within the biogas industry or service and supply chain. The incentive would support rural economic diversification. An example incentive would be a wage subsidy program, such as the "Career Focus Wage Subsidy Program" offered by BioTalent Canada (BioTalent Canada, 2016).

Research funding should be focused towards specific areas where knowledge is lacking, especially pertaining to Alberta's climate, feedstock, regulatory science, and infrastructure development. In particular, research should be focused on:

1. Developing a robust GHG quantification protocol for avoided methane emissions from employing AD technology in the Alberta climate. Specifically, quantification of avoided upstream emissions from reduced storage time in manure lagoons, and avoided downstream emissions from the application of digestate biofertilizers rather than manure or inorganic fertilisers.
2. The impacts of AD and different feedstocks on contents of concern (pathogens, nutrients, heavy metals, weed seeds and other pollutants) in the resulting digestate, with a view to developing quality standards for digestate.
3. Natural gas grid infrastructure and connection for small RNG producer grid injections, and implementation of biogas to RNG upgrading technologies in Alberta.
4. New markets for digestate products.

Drivers: Alberta Policy and Climate Leadership Plan

The major drivers for a thriving biogas industry in Alberta mirror those on a global scale, which are to reduce GHG emissions and reduce landfill waste (Visiongain, 2016). As a result of increasing regulatory and public pressure, it is predicted that AD will begin to play a fundamental role in the global energy mix over the next ten years (Visiongain, 2016). The Alberta provincial government recently enacted the Alberta Climate Leadership Plan that includes an accelerated phase out of coal-powered electricity, transitioning to a system where one-third of coal-fired generation is replaced by natural gas generators, and two-thirds by renewable energy. The Plan also includes an economy-wide price on GHG emissions of $30/tonne CO_2e that will be phased in; and a 100Mt annual limit on oil sands emissions (currently at approximately 70 Mt). Methane emissions will be capped at 45% below 2014 levels by 2025.

Therefore, renewable energy derived from AD, and avoided upstream methane emissions from manure and landfills are in alignment with the province's Climate Leadership Plan. There are several ways the use of ADs to produce biogas from organic wastes reduces GHG emissions compared to business-as-usual. According to government figures, diverting MSW from landfill to an AD would result in net CO_2e emissions reductions of approximately 213,690 tonnes per year, whereas the use of landfills to dispose of food waste has the highest carbon footprint (The Province of Alberta, 2007). These figures do not take in to account the avoided emissions as a result of offsetting fossil fuel derived electricity.

In Europe, the key contributors include regulatory restrictions on waste management and financial support for renewable energy, as methods of meeting GHG emissions targets (AEBIOM, 2012). Many jurisdictions also have strong financial incentives for biogas producers through guaranteed feed-in-tariffs, successful markets for non-energy products, and strong markets for renewable fuels created through transport fuel regulations (Visiongain, 2016). Governments are also motivated by energy security benefits, especially in jurisdictions that import much of their energy resources (Visiongain, 2016).

In North America, growing public concern over GHG emissions, and in particular waste management, is a strong driver which is exemplified through the growth of voluntary markets for renewable energy (Canadian Gas Association, 2014) (Visiongain, 2016). In BC, FortisBC runs a voluntary program where customers can opt to pay a premium for a portion of their natural gas use to be sourced from renewable AD from agricultural waste (Canadian Gas Association, 2014) (Canadian Gas Association, 2016). The program has 7,000 customers to date, indicating that consumer demand can create a viable biogas project (Canadian Gas Association, 2016).

Techno-Economic Models

A techno-economic model was developed and applied to three generic biogas plant cases using financial and operational data provided by three operational plants in Alberta. The cases represent:

Case 1: Pulp and Paper Mill – A forestry industry biogas plant using AD as a wastewater treatment process and using generated electricity on-site.

Case 2 – An agricultural industry-based digester, utilising some food processing waste, and **charging tipping fees to some feedstock providers**.

Case 3 – An agricultural industry-based digester, utilising some food processing waste, and **not charging tipping fees to feedstock providers**.

It is expected that the cases represent a general overview of the majority of potential biogas projects in the province. The results should be used to inform decisions on areas of further research required to develop the policy and market conditions favourable to a diverse Alberta biogas industry.

Model Characteristics and Assumptions

The internal rate of return (IRR) is calculated for a 30-year period for each case, based on a fixed inflation rate of 2%, a weighted average capital cost of 0% (due to assumed capital costs from equity, incentives or grants) and using the full capital cost of the project (i.e. private investment and capital grants together). IRR is calculated with all liabilities including debts, and remains above the minimum acceptable rate of return. A range of capital grant incentives of 0%, 25% and 50% are modelled for each case, representing the range of grant funding obtained by the three operational plants that inform these models. An IRR of 5% was modelled for each case; while this is lower than some conventional energy investors would expect, it is more common for renewable energy providers in the current energy climate, and captures developers such as farmers who may opt to install an AD mainly as a waste management tool without expectations for large revenue generation.

Transportation costs for feedstock and digestate are assumed to be nil, or included in the tipping fees. This is because the baseline condition for an on-site or on-farm digester without AD, and off-site feedstock providers, would likely incur similar transport costs for waste management.

Carbon offsets for electricity grid displacement were calculated using the *Distributed Renewable Energy Generation* protocol, and the appropriate emissions factor for electricity grid displacement with renewable generation (0.59tCO_2e/MWh) (Alberta Environment and Sustainable Resource Development, 2013) (Environment and Sustainable Resource Development, 2015). It should be noted that a displacement factor of 0.64tCO_2e/MWh should be used for electricity generated and used on-site, but was not employed to allow simplicity, ease of comparison between cases, and to broaden the scope of the analyses to several different business models. Estimates of carbon credits generated in each case are therefore conservative estimates.

An estimate was also made for the carbon credits that could be gained from avoided upstream and downstream methane emissions, due to reduced manure and pulp storage, use of digestate as a fertiliser, and potentially reduced emissions from pulp digestate. The potential carbon credits gained from avoided methane emissions was estimated to be an additional 30%. This figure should be viewed only as an estimate and is included here to show the potential impacts of including avoided methane emissions in an offset quantification protocol for anaerobic digestion/decomposition.

An average electricity sale price of $42/MWh was taken from the 3-year sale prices provided by current operators. Despite the recent low electricity prices in Alberta, prices are expected to rise in the future with modifications to the energy market; $42/MWh therefore appears to be a reasonable estimate in the medium-term. The same electricity sale price was applied to Case 1, despite the assumption that the operation uses all generated electricity on-site. While it may be expected that the sale price, or electricity offset savings, should be greater in Case 1 due to offsetting purchased electricity, the plant is likely to gain a preferential tariff from the WSP, and will still import electricity, incurring transmission and connection costs. It is therefore assumed that electricity offset savings for Case 1 are approximately equivalent to the wholesale cost of electricity.

Similarly, an on-farm digester could be expected to make additional savings by using biogas to offset heat and electricity requirements on-farm; this is an important feature of the German biogas industry. However, an on-farm digester could also be expected to have a lower biogas potential due to increased manure and reduced food processing waste feedstocks. These factors are not explicitly considered in the analyses presented here, mainly due to a lack of Alberta-based data, but could be explored further with the formation of a financial modelling working group.

It should also be noted that, based on data obtained from the (2) existing agriculture-based biogas operations of different sizes in Alberta, biogas operations of this type are very scalable with comparable break-even costs. Therefore, at the definition provided by this model, it can be assumed that the data are generally applicable to agriculture-based digesters of varying sizes. The only difference between Cases 2 and 3 is the charging of tipping fees. Therefore, differences in the results represent the potential impacts of a change in organic waste management regulations, either in the form of a ban or a levy for landfilling of organic wastes. Tipping fees are assumed to be generated only from food-processing wastes and MSW.

Modelling of minimum electricity sale prices excludes revenue generated from carbon offset sales, in order to replicate an REP-type program, and inform the reader of potential fixed ‘standing price’ points (Figures 3, 6 and 9). Modelling of offset credit sales, however, includes electricity sales to replicate the current electricity and offset regulatory system (Figures 4, 7 and 10).

Additional revenue from incentives such as the BPCP and BPP are not included in the analyses. It is believed that the GoA intends to move away from such incentive schemes, and for the Alberta biogas industry to become self-sustaining. By removing these incentives from the model, the results more clearly demonstrate potential pathways for a sustainable biogas industry without direct government subsidies. However, it should also be noted that the calculations of minimum electricity and carbon offset prices

capture the influence of potential incentive schemes based on electricity sales or carbon offsets respectively.

Table 10 shows the key input data for each model. Tabulated results are presented for each model in the relevant sections below.

Table 10: Key Model Input Data for Cases 1 to 3

Factor	Case 1: Pulp and Paper Mill (Large Industrial Application)	Case 2: Agricultural and Food Processing Waste (Waste Management Facility)	Case 3: Agricultural and Food Processing Waste (Large On-farm Digester)
Capital Cost ($M)	40	30	30
Capacity	3.3M m^3/yr	50,000 t/yr	50,000 t/yr
Maximum biogas production (m^3/day)	40,000	25,000	25,000
Electricity Generation (MWh/year)	39,000	22,000	22,000
Operating Cost	$2.0M (5% of capital cost)	$1.5M (5% of capital cost)	$1.5M (5% of capital cost)
Construction Period (years)	3	3	3
Tipping Fee Revenue ($/yr)	NA	375,000 ($15/ton for 50% feedstock)	NA
Process Efficiency Savings ($/yr)	715,000	NA	NA

Case 1: Pulp and Paper Mill - Industrial Biogas Application

This case models an AD operation in a pulp and paper mill in the forestry sector, using pulp and paper production and forestry waste residues as feedstocks. The main motivators for the operation are waste management and generation of electricity to offset on-site energy use (represented as a revenue source in this model). It is important to note that offsets in heating are not factored in to this model due to a lack of Alberta-specific data, but new projects would likely consider (CHP) operations.

Electricity savings and carbon credit sales are the only revenue streams for the facility. While there are no tipping fees associated with the operation, cost savings are seen through energy efficiencies associated with reduced aeration required in waste management and treatment processes. The benefits of

implementing of biogas technology in this function are twofold: reduced electricity demand for waste treatment processes, and offsetting of electricity used on-site.

The results show that, for this case, the break-even price to gain 0% IRR considering electricity sales only with no capital grant funding, is $58/MWh.

Table 11: Techno-Economic Model Results for Case 1 – Pulp and Paper Mill

		Without Capital Grants	With Capital Grants	
			25%	50%
With 42 $/MWh electricity sale price	% IRR (without carbon credit)	-5.1	0.8	6.8
	% IRR (with 30 $/t carbon credit)	0.32	4.6	10.6
	% IRR (with 50 $/t carbon credit)	2.5	6.7	12.8
	$/t Carbon credit to gain 0% IRR	27	0	0
	$/t Carbon credit to gain 5% IRR	77	32	0
	$/t Carbon credit to gain 10% IRR	151	88	24
$/MWh Minimum electricity price without carbon credit	0% IRR	**58**	39	19
	10% IRR	131	94	56
GHG emission reductions due to electricity grid displacement only *(electricity grid displacement factor 0.59 kg CO_2e/MWh)*		23,010 tonne of CO_2e/yr		
GHG emission reductions due to electricity grid displacement plus additional 30% for avoided methane emissions (*electricity grid displacement factor 0.59kgCO_2e/MWh*)		29,913 tonne of CO_2e/yr		

* The displacement factor used in the analysis assumes electricity is exported to the grid. While the displacement factor for electricity used on site is 0.64kgCO_2e/kWh, a value of 0.59kgCO_2e/kWh is used here to allow better analysis and comparison with other cases under the program suggested in *Solution 1*. It should therefore be noted that the offsets presented for this case are a conservative estimate.

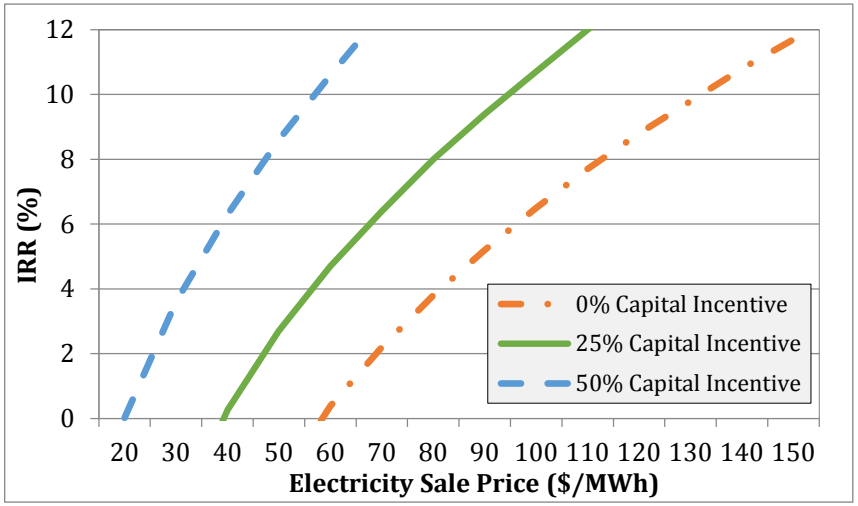


Figure 3: Case 1 Variation in % IRR with Electricity Sale Price ($/MWh) with Zero Carbon Credit Sales ($/tCO2e) for 0%, 25% and 50% capital grant incentives

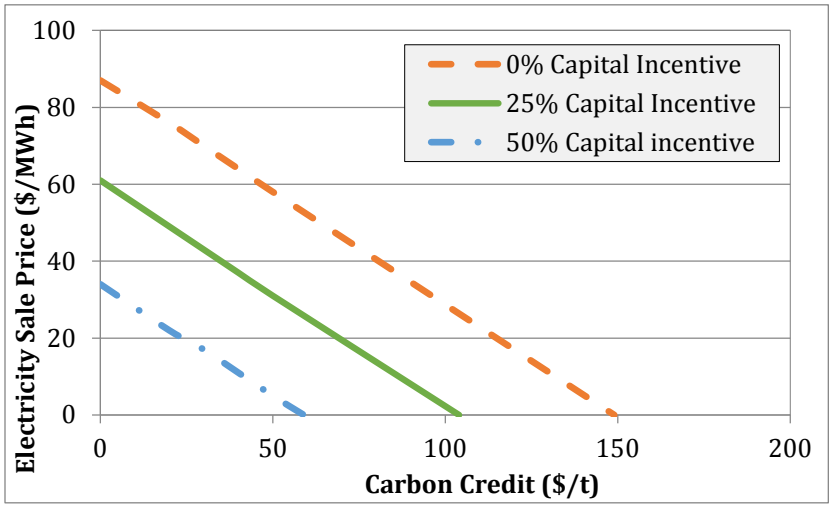


Figure 4: Case 1 Minimum Electricity Sale Price ($/MWh) and Carbon Credit Sale Price ($/tCO2e) Required to Obtain 5% IRR for 0%, 25% and 50% capital grant incentives

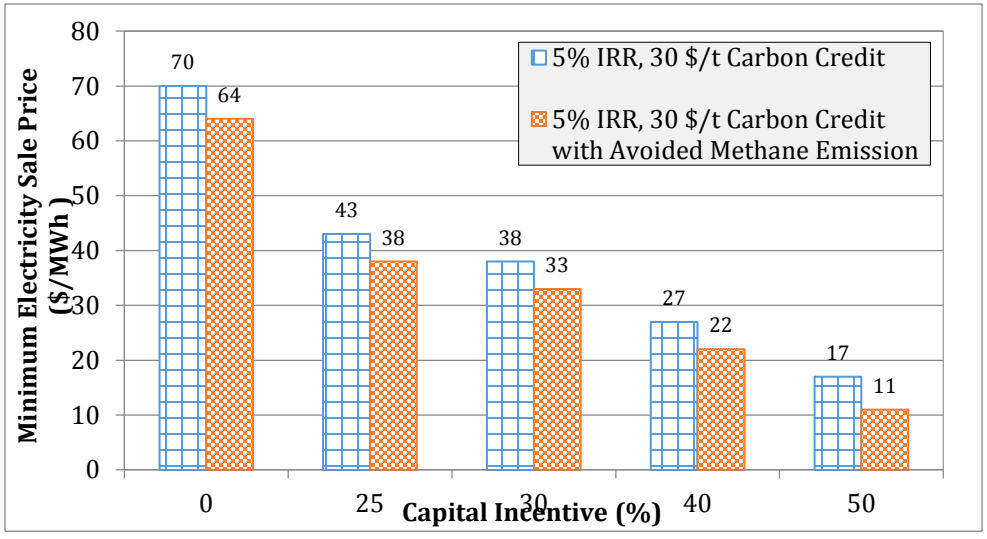


Figure 5: Case 1 Variation in Minimum Electricity Sale Price ($/MWh) with Capital Incentives required to achieve 5% IRR, considering Carbon Credit Sales Including and Excluding Additional Revenue from Avoided Methane Emissions at $30/tCO2e

Case 2: Agricultural industry-based digester including tipping fees

This model is based on an AD operation utilising agricultural and food-processing residues; a minimum proportion of 50% livestock manure feedstock is assumed to comply with the MOU. Such an operation might be found in an agricultural area, for example “feedlot alley” in Southern Alberta. The main revenue sources for the operation are electricity and carbon offset credits sales, and income from charging tipping fees ($15/tonne) to some feedstock providers, such as those in the food-processing industry (estimated at 50% total feedstock volume). This case represents a biogas plant operating under a ban or levy applied to landfilling organic waste.

The results show that, for Case 2, the break-even price to gain 0% IRR, considering only electricity sales with no capital grant funding, is $84/MWh. Including a 50% capital grant, the break-even price drops to $67/MWh. These prices are competitive with the AESO (2016) research into break-even prices for both wind and solar power plants, but may not be competitive with future solar and wind bids in a competitive REP (Roberts, 2016).

Increasing the carbon offset credits by 30%, and therefore the revenue generated from their sale, to reflect potential income generated from avoided methane emission offsets, will reduce the minimum electricity sale price required to achieve 5% IRR by $5/MWh.

Table 12: Techo-Economic Model Results for Case 2 – Agriculture-based Waste Management Business

		Without Capital Incentives	With Capital Incentives	
			25%	50%
With 42 $/MWh electricity sale price	% IRR (without carbon credit)	NA	NA	NA
	% IRR (with 30 $/t carbon credit)	-6.6	-5.4	-3.5
	% IRR (with 50 $/t carbon credit)	-2.6	-1.2	1.1
	$/t Carbon credit to gain 0% IRR	72	58	43
	$/t Carbon credit to gain 5% IRR	139	108	77
	$/t Carbon credit to gain 10% IRR	237	182	126
Without Carbon Credit	$/MWh Minimum electricity price to gain 0% IRR (break-even)	**84**	76	67
	$/MWh Minimum electricity price to gain 10% IRR	182	149	116
GHG emission reductions due to electricity grid displacement only *(electricity grid displacement factor 0.59 kg CO_2e/MWh)**		12,980 tonne of CO_2e/yr		
GHG emission reductions due to electricity grid displacement plus additional 30% for avoided methane emissions (*electricity grid displacement factor 0.59kgCO_2e/MWh*) *		16,874 tonne of CO_2e/yr		

* The displacement factor used in the analysis assumes all generated electricity is exported to the grid. This is therefore a conservative estimate since some electricity could be used to offset on-site usage depending on plant location.

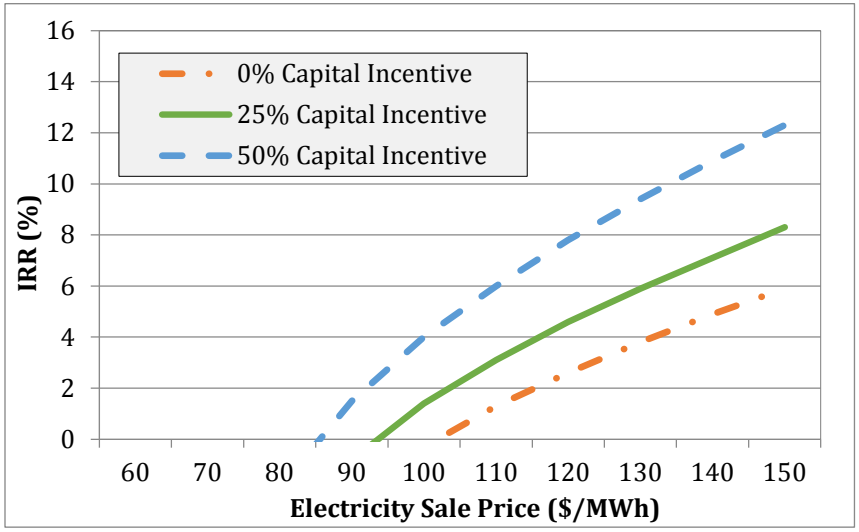


Figure 6: Case 2 Variation in % IRR with Electricity Sale Price ($/MWh) with Zero Carbon Credit Sales ($/tCO₂e) for 0%, 25% and 50% capital grant incentives

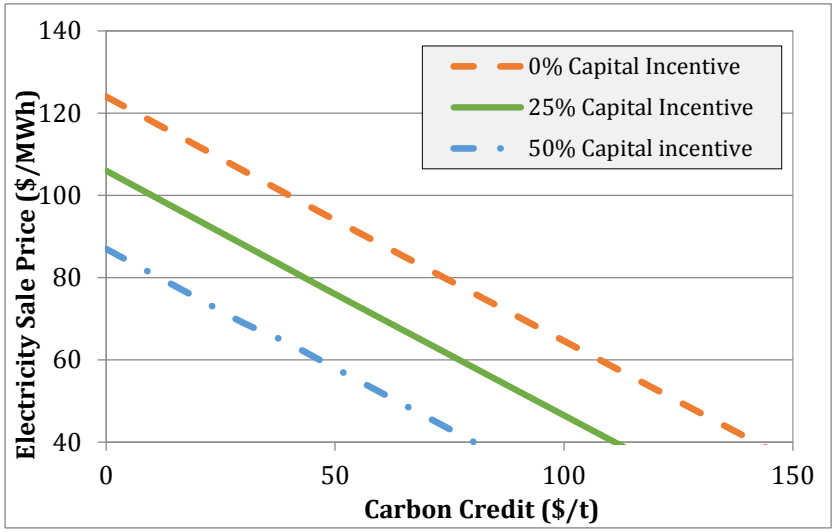


Figure 7: Case 2 Minimum Electricity Sale Price ($/MWh) and Carbon Credit Sale Price ($/tCO₂e) Required to Obtain 5% IRR for 0%, 25% and 50% capital grant incentives

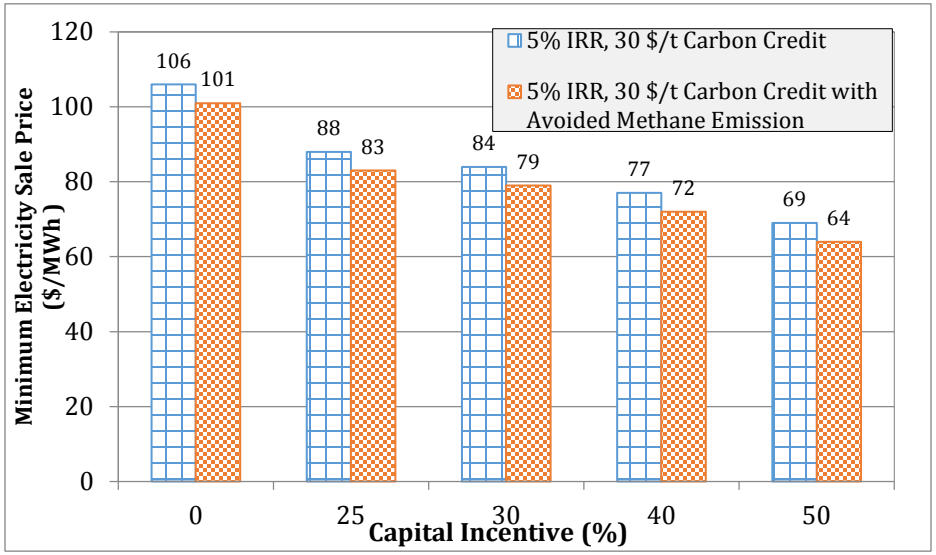


Figure 8: Case 2 Variation in Minimum Electricity Sale Price ($/MWh) with Capital Incentives required to achieve 5% IRR, considering Carbon Credit Sales Including and Excluding Additional Revenue from Avoided Methane Emissions at $30/tCO₂e

Case 3: Agricultural industry-based digester excluding tipping fees

Case 3 uses the same model input data as Case 2, but excludes revenue generated by tipping fees. This case therefore represents a biogas operation in an agricultural area, such as an on-farm. The digester would likely be operated mainly as a farm waste management facility for the farm owner, with some food-processing waste feedstocks to boost the AD process. The main sources of income for this operation are electricity and carbon offset credit sales.

The results show that, for this case, the break-even price to gain 0% IRR, considering only electricity sales with no capital grant funding, is $101/MWh. Including a 50% capital grant, the break-even price drops to $84/MWh. These prices are competitive with the AESO (2016) research into break-even price for solar power plants ($150/MWh), but is unlikely to compete with future bids from solar or wind projects under the current REP (Roberts, 2016).

As with case 2, under the current system of electricity sales and carbon credits, both sources of revenue would need to increase significantly to provide a 5% IRR; a carbon credit price of $50/t$CO_2$e, a 50% capital grant and an electricity sale price of $75/MWh would be required to achieve a 5% IRR. Comparing cases 2 and 3, the income generated by charging tipping fees reduces the average electricity sale price required to gain 5% IRR over 30 years significantly, by approximately $17-18/MWh.

As would be expected, increasing the revenue generated from the sale of carbon offset credits by 30%, to reflect potential income generated from avoided methane emission offsets, will reduce the minimum electricity sale price required to achieve 5% IRR by $5/MWh, equivalent to case 2.

Table 13: Techno-Economic Model Results for Case 3 – Large On-farm Digester

		Without Capital Grants	With Capital Grants	
			25%	50%
With 42 $/MWh electricity sale price	% IRR (without carbon credit)	NA	NA	NA
	% IRR (with 30 $/t carbon credit)	NA	NA	NA
	% IRR (with 50 $/t carbon credit)	-10.3	-9.3	-7.6
	$/t Carbon credit to gain 0% IRR	101	87	72
	$/t Carbon credit to gain 5% IRR	168	137	106
	$/t Carbon credit to gain 10% IRR	266	211	155
Without Carbon Credit	$/MWh Minimum electricity price to gain 0% IRR (break-even)	**101**	93	84
	$/MWh Minimum electricity price to gain 10% IRR	199	166	133
GHG emission reductions due to electricity grid displacement only *(electricity grid displacement factor 0.59 kg CO_2e/MWh)*		12,980 tonne of CO_2e/yr		
GHG emission reductions due to electricity grid displacement plus additional 30% for avoided methane emissions (*electricity grid displacement factor 0.59kgCO_2e/MWh*) *		16,874 tonne of CO_2e/yr		

* The displacement factor used in the analysis assumes all generated electricity is exported to the grid. This is therefore a conservative estimate since some electricity could be used to offset on-site usage depending on plant location.

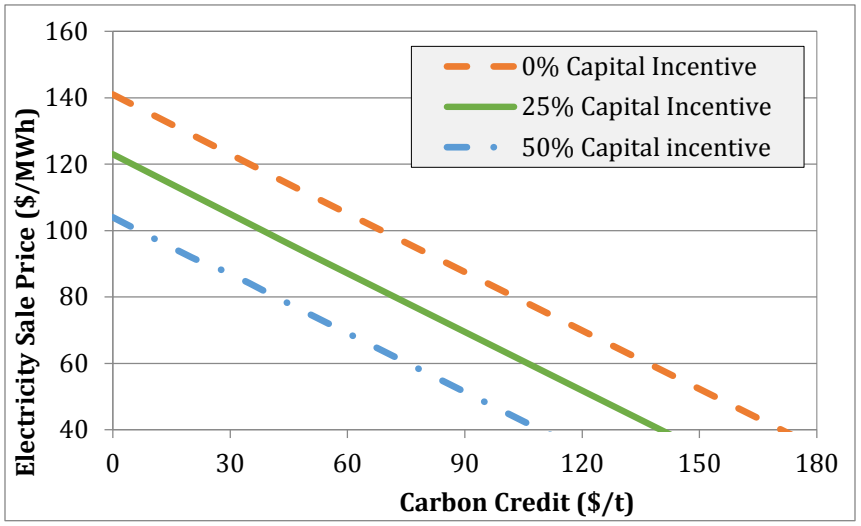


Figure 9: Case 3 Variation in % IRR with Electricity Sale Price ($/MWh) with Zero Carbon Credit Sales ($/tCO$_2$e) for 0%, 25% and 50% capital grant incentives

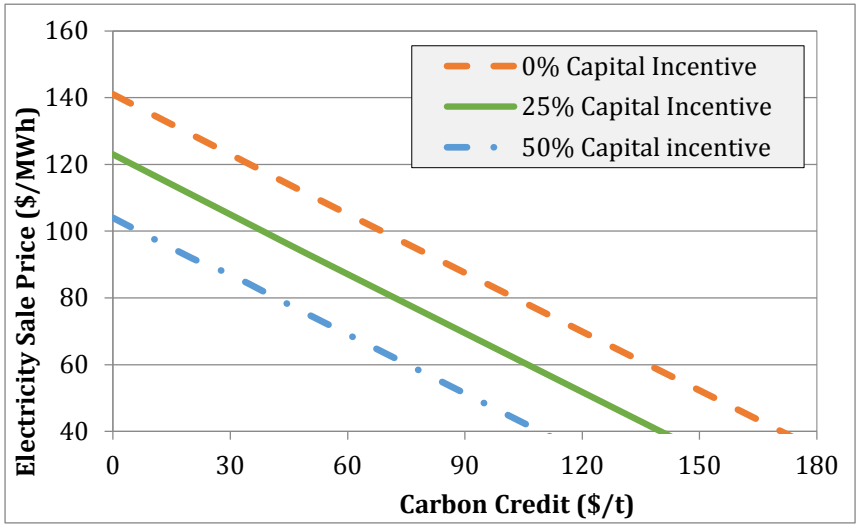


Figure 10: Case 3 Minimum Electricity Sale Price ($/MWh) and Carbon Credit Sale Price ($/tCO$_2$e) Required to Obtain 5% IRR for 0%, 25% and 50% capital grant incentives

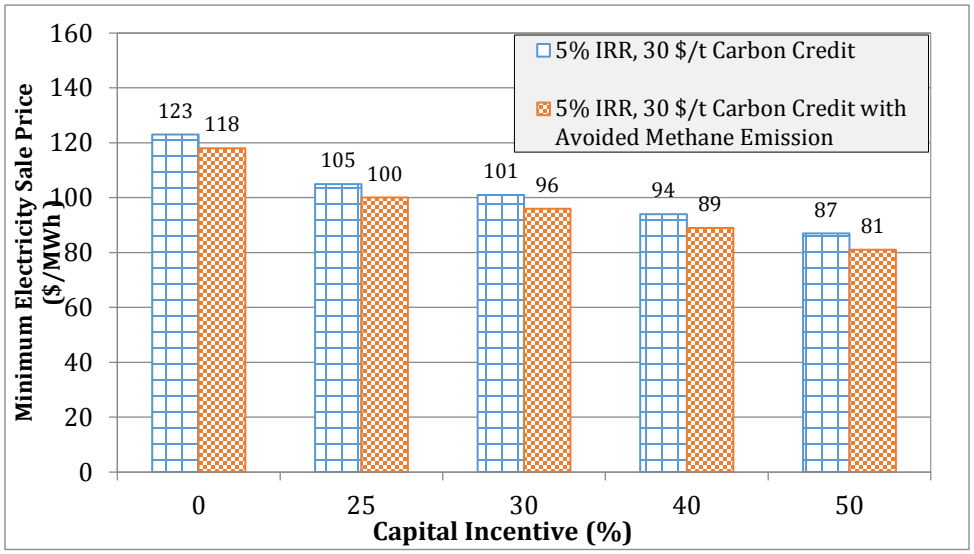


Figure 11: Case 3 Variation in Minimum Electricity Sale Price ($/MWh) with Capital Incentives required to achieve 5% IRR, considering Carbon Credit Sales Including and Excluding Additional Revenue from Avoided Methane Emissions at $30/tCO$_2$e

Conclusions from Cases 1-3

The break-even prices presented at 0% IRR without capital grants could be used to inform a fixed 'standing price' for a 'Bio Carve-out' REP, as described in Solution 1, and to inform comparisons with biogas projects and other generation technologies. Figures 3, 6 and 9 also provide an indication of the fixed 'standing price' for electricity sales that would be required to achieve a certain IRR. The results suggest that when AD is used as a waste management process in a large industrial operation, as presented in Case 1, the project is more economically feasible and would require a much lower electricity sale price than agriculture-based operations. It would be expected that biogas projects associated with industrial operations use the generated electricity on-site and hence do not receive revenue from electricity sales, but do generate more carbon offset credits, and electricity savings. This is an important point when considering a 'standing price' and policy framework for a 'Bio Carve-out' REP; generated electricity should be primarily used on-site with only excess electricity sold to the grid.

The results for each case show that, under the current system receiving revenue from electricity sales, offset credits, tipping fees, process efficiencies, and excluding revenue from provincial programs such as the BPP, electricity and offset credit prices will need to increase substantially to achieve a reasonable (5%) IRR without capital grants, as presented in Figures 4, 7 and 10. The industrial application modelled in case 1, however, could achieve a 5% IRR with a 25% capital grant, a \$30/tCO_2e carbon offset price, and an electricity sale price of \$43/MWh. These figures are reasonable under the current offset credit system and forecasted electricity sale prices, although, as mentioned above, electricity sales for this case are effectively electricity savings. Agriculture-based projects in cases 2 and 3 would require an increase in electricity sale prices to \$69/MWh or \$87/MWh, with and without tipping fees respectively, to achieve 5% IRR at an offset price of \$30/tCO_2e, with a 50% capital grant.

Charging tipping fees at \$15/t, as demonstrated in Case 2, is a significant source of revenue to agriculture-based operators who can charge tipping fees in their specific business environment. Comparing cases 2 and 3, revenue generated through tipping fees reduced the electricity sale price required to achieve 5% IRR over a 30-year project lifetime by \$17-18/MWh. Not every agriculture-based biogas operation will be able to charge tipping fees, especially smaller on-farm operations that use AD as an on-farm waste management process rather than a separate business enterprise. Tipping fees should therefore be seen as an additional revenue source for biogas operators operating as a for-profit, off-site waste management business. The introduction of a ban or levy applied to landfilling of organic waste would increase this opportunity for biogas operators.

Similarly, including avoided methane emissions at an estimated additional 30% of offset credit generation, reduces the electricity sale price required for 5% IRR in each case by \$5-6/MWh. While this analysis is only an estimate of the potential income that could be generated by including upstream and downstream avoided methane emissions, it is clear that the potential for offset credits generated as a result could be a significant source of revenue for biogas operators, and could increase biogas competition with other electricity generators.

Comparison with Wind and Solar, and Reasons for a Separate 'Bio Carve-out' REP

The break-even prices for the modelled cases can be seen at 0% IRR without capital incentives or offset credit revenue:

- Case 1: $58/MWh
- Case 2: $84/MWh
- Case 3: $101/MWh

These break-even prices can be used to inform recommendations for policy and further research, particularly the development of a 'Bio Carve-out' REP. However, these break-even prices should be considered with the limitations of the model. The biogas data presented in cases 1-3 are based on data collected from existing operations within Alberta. As discussed throughout this report, there are a number of financial challenges to the Alberta biogas industry that have prevented some projects from operating successfully. This implies that the remaining projects, upon which the above cases are based, are at the limit of what can be achieved in Alberta under the current conditions. Therefore, the break-even prices presented here may represent the absolute minimum electricity sale price biogas projects require. It is likely that smaller projects based outside of large industrial applications, and particularly newcomers to the industry, will require higher electricity sale prices to be financially viable. However, the range of break-even prices for different business models and types of biogas operations could inform a number of fixed 'standing prices' that could be employed in a 'Bio Carve-out' REP.

The results presented in the in the AESO (2016) recommendations for a utility-scale REP (wind: $80/MWh and solar: $150/MWh) may not be comparable with biogas operations of a much smaller capacity. It is also argued that the break-even prices of wind and solar generation could be much lower than the AESO research suggests (Roberts, 2016). It is therefore difficult to compare the data presented here with the break-even prices for wind and solar power plants due to a lack of Alberta-specific data of comparable capacity.

The business models for solar and wind versus biogas are also likely to be different. Wind and solar power plant operators will build their business model purely on the benefits provided by electricity and carbon offset credit sales, whereas biogas operators may construct a plant for a myriad of reasons including waste management, job creation, sales or preferential use of digestate, CHP operations and so on. Solar and wind developers are therefore more likely to look for economies of scale and build power plants larger than 5MW capacity, rendering competition with biogas plants invalid. Consequently, a separate 'Bio Carve-out' REP designed specifically for biogas operators is recommended as the best solution for electricity market access.

The authors recommend the formation of a working group to carry out further research into financial modelling of an Alberta biogas industry and to explore appropriate policy pathways. Such analysis may include the impacts of capital grant incentives to inform capital grant programs, and in-depth analysis of different biogas plant 'types' and business models, including IRR's applicable to different investors and projects.

Recommendations and Conclusions

Based on the findings of this paper, there are many potential options and solutions to overcome the challenges to an Alberta biogas industry. Each solution and complimentary policy measure presented in this paper should be considered as a feasible pathway towards a successful biogas industry. However, in the interest of focusing efforts, it is the opinion of the working group that the following 4 initiatives provide the most feasible pathway towards a successful and self-sustaining biogas industry in Alberta:

1. A 'Bio Carve-out' of the recently recommended REP for biogas generators, including a fixed 'standing price' for 20 years, and reduced or subsidised grid connection costs. Continued ERA and/or AER capital grant financing for up to 50% capital costs to bridge the gap to industry maturity.
2. Build on current collaborative efforts to develop a clear permitting and regulatory pathway for biogas proponents. A long-term, simplified solution could be achieved through changes to digestate regulations, and development of a digestate protocol that specifies the feedstocks and processes to produce digestate to a reliable quality standard.
3. Increase non-energy revenue sources through a ban or levy on landfilling organic waste, and/or development of a quantification offset protocol to include avoided upstream methane emissions.
4. Create a provincial CFS, modelled on the BC RLCFRR and including RINs, in association with research and investment in RNG infrastructure and market development. This will also allow Alberta to take advantage of the proposed national CFS.

The most important challenge to biogas proponents and operators, as identified by the case studies here, is market access and the financial value of biogas in the deregulated Alberta electricity grid. A number of solutions are presented to address this challenge, including the development of a 'Bio Carve-out' REP specific to the biogas or bioenergy industry, or the introduction of an RPS requiring a fraction of electricity be sourced from bioenergy.

The solution that appears to be most feasible is to **develop and implement is an adapted 'Bio Carve-out' REP**, applicable to biogas generators, and applying a fixed 'standing price' rather than an auction. The data in this report show that biogas is financially competitive with solar and wind technologies, with many added benefits including the ability to provide reliable, dispatchable electricity, and a consistent baseload regardless of weather conditions. Employing a set 'standing price' for electricity exported to the grid has several advantages:

- Gives the GoA control over payment for biogas electricity generation, and the 'type' of biogas plants the province wants to invest in.

- Improves investor confidence and business planning by providing a long-term guaranteed fixed price for electricity.
- Encourages private investment in the industry while keeping production costs low.
- Creates a mechanism for fair market access for biogas while encouraging innovation at a governable cost.
- Reduces the potential for selection for certain technologies or 'types' of AD operations based only on the price of electricity generation.

Differences between the pool price and standing price could utilise funds raised by the carbon levy. Capital grant funding is also vital to initiate and bridge the gap towards a mature biogas industry in Alberta. Grant funding from ERA and/or AER bioenergy grant programs should continue to provide support to developers, and could also utilise funds raised by the carbon levy.

The proposed introduction of a capacity market where generators receive payments for providing dispatchable electricity would provide biogas operators with additional revenue which recognises this important benefit of the technology. Full details are not yet available owing to its' recent proposition, but decision-makers should ensure biogas projects are included in its' development.

Streamlining the permitting process for biogas proponents would improve the ability to attract investors and investor confidence, reduce permitting timelines, and assist developers and operators in decision-making. We recommend the development of a clear regulatory framework that is accessible to both project developers and regulators, and that addresses inefficiencies and inter-agency coordination. Formal working agreements between the relevant agencies, particularly AUC and AEP, would ensure efficiencies in the permitting process for each agency. Permitting could be enhanced further with administration through a regulatory lead who would disseminate information to the relevant agencies and the developer.

The development of the MOU between AEP and NRCB regarding digestate handling from mixed-source (third party) feedstocks has alleviated some regulatory burden from biogas operators and should be held as an example of successful inter-agency coordination. However, a modification to the AOPA and EPEA regulations, and the municipal wastewater regulations currently under review, to specifically deal with mixed-source digestate on-farm will be required for a long term and simplified solution. Likewise, a protocol or policy specific to mixed-source digestate, similar to the approach taken by the Province of Ontario, could regulate feedstock types and quantities, and the AD processes required, to produce digestate to a required quality standard. Development of such a policy should be undertaken in conjunction with scientific research into feedstock and AD process impacts on contents of concern in digestate.

The potential for **alternative revenue streams for biogas** operators could be developed with the introduction of a **ban or levy on landfilling organics** and/or development and implementation of a **carbon offset protocol including offsets generated from avoided upstream and downstream methane emissions.** These non-energy revenue source would incent GHG emission reductions and environmental benefits through the use of AD. Presently, landfill fees for organic waste disposal are low and do not take into account the full impacts of landfilling organics. The current anaerobic decomposition offset quantification protocol does not include all the avoided methane emissions associated with the process. Data are lacking regarding avoided upstream emissions from storage of manure in lagoons and potential avoided downstream methane emissions from the land application of digestate rather than untreated manure; more research on the effect of the Alberta climate on these processes is required to develop an appropriate protocol. Creating regulation and an offset protocol to account for the full environmental benefits of using AD as a waste management process will allow the GoA to reward these specific attributes of AD operations.

Development of markets for RNG through the development and implementation of a provincial CFS based on the BC RLCFRR. The inclusion of RINs will allow fuel suppliers further flexibility in how they can meet their obligations under a provincial CFS. Further research and infrastructure investment will be required. However, investment in this area in the short-term could be worthwhile with the future introduction of a national CFS. Employment of NGVs in GoA and municipalities transport fleets, and tax breaks for private purchases of (or conversion to) NGVs will encourage infrastructure development, lower costs of NGVs and create a market for RNG as a transport fuel while improving air quality in urban areas. A long-term outlook towards a national CFS will further improve investor confidence in the Alberta biogas industry, and allow Alberta to become a national powerhouse for RNG production.

Appendix 1: Biogas Economic Impact by Capacity

Viresco Solutions, in collaboration with the Waterfall Group, conducted an analysis of the economic impact of the bioenergy sector in 2015 (Viresco Solutions, 2015). The results of the biogas sub-sector only are presented in Table 14 below. At the time of conducting that study, there were three operating agricultural or mixed-agricultural biogas facilities in the province that comprised 4.05 MW of installed generation capacity.

Table 14: Economic impacts of biogas facilities in Alberta of existing facilities and planned facilities. Impacts of existing projects are also normalized to 50 MW and 100 MW. This data was adapted from the 2015 report, revised 2016.

OPERATIONS	**Existing Projects (4.05MW capacity)**	**Planned Projects (61.90MW capacity)**	**Impact Per 50 MW**	**Impact Per 100 MW**
Impact on GDP ($M)	$ 0.65	$ 19.23	$ 8.00	$ 15.99
Impact on labour Income ($M)	$ 0.39	$ 11.67	$ 4.85	$ 9.71
Direct Salaries	$ 1.05	$ 9.95	$ 12.93	$ 25.87
Total Labour Income Impact	$ 1.44	$ 21.62	$ 17.79	$ 35.57
Impact on Employment required (person years)	5	139	58	115
Direct Jobs	14	133	173	346
Total Jobs Impact employment required (Direct & Indirect)	19	272	231	461
Total value of goods for final consumption or export, and goods consumed in production ($M)	$ 1.65	$ 224.62	$ 20.32	$ 40.63
CONSTRUCTION				
Impact on GDP ($M)	$ 22.80	$ 124.80	$ 281.44	$ 562.88
Impact on labour Income ($M)	$ 15.74	$ 86.16	$ 194.29	$ 388.59
Impact on Employment required (person years)	205	1,120	2,526	5,052
Total value of goods for final consumption or export, and goods consumed in production ($M)	$ 52.38	$ 286.76	$ 646.68	$ 1,293.36

The same study estimated that an additional 61.90 of installed capacity would be feasible to be designed, planned, or commissioned in Alberta between 2015 and 2020. (Note that this estimate is a fraction of the capacity that the province could technically see developed.) The economic impact figures were calculated

using the Alberta Treasury Branch Economic Multipliers model (2015). Inputs to the model include actual reported jobs and electricity sales, and outputs include impacts to GDP, direct and indirect employment, labour income and total value of goods for consumption or export, for both the construction and operation phases.

The economic indicators calculated for the existing capacity was normalized to a megawatt installed capacity basis and scaled to 50 MW or 100 MW for the purpose of comparison with other economic impact figures. Per 100 MW of installed biogas capacity, an estimated 346 jobs will be created, resulting in labour income of $9.71 million and a boost to provincial GDP of almost $16 million. The construction of those 100 MW would require over 5,000 person-years of employment.

Appendix 2: Case Studies

This section presents regulatory and technical case studies. Regulatory case studies include descriptions of the jurisdictions of Ontario, Washington State, and more broadly, Europe. Technical case studies present three of the Alberta anaerobic digestion facilities that contributed data to this white paper.

Case Study: Ontario

Realising the benefits of using RNG as a renewable energy source, Canadian natural gas utilities have set a target of 5% RNG-blended natural gas in the pipeline distribution system by 2025, and 10% by 2030 (Government of Ontario, 2016). Biogas production can be made more efficient with the addition of off-farm wastes, but can also lead to regulatory complications when the digestate is used as a nutrient-rich organic fertiliser (OMAFRA, 2016). The Government of Ontario has sought to address these regulatory issues and create a market for RNG and biogas (OMAFRA, 2016) (Government of Ontario, 2016).

The Ontario Nutrient Management Act (2002) (Act), and complimentary Waste Management Regulation, have addressed regulatory issues to allow the Ontario biogas industry to utilise digestate from mixed-source feedstocks in AD. Changes to the Act allow on-farm digestion of off-farm feedstocks without requiring a Certificate and Approval for waste disposal, provided certain regulations and procedures specific to biogas production are followed (OMAFRA, 2016). The Nutrient Management Regulation (OR 267/03) outlines the definition of, and requirements for, land application of off-farm waste digestate, and for a RMADF. To receive and process off-farm material, and apply the digestate to agricultural land, the facility must have an approved nutrient management strategy, an operational AD facility, and feedstock must be treated in an RMADF according to specific operational procedures (OMAFRA, 2016).

Specifically, the regulation prescribes design specifications and limits of the AD unit; a minimum of 50% on-farm materials for use in AD; considers odour, noise and run-off issues; limits the total volume of off-farm feedstock materials; and categorises off-farm materials for non-allowable materials or specific treatment requirements (Government of Ontario, 2016). The nutrient management strategy must include: operational procedures for handling material inputs and outputs, appropriate nutrient storage

facilities for off-farm AD materials, a contingency plan, and describe how each meets the requirements of the Nutrient Management Regulation (OR 267/03).

By altering the Nutrient Management Act (2002), and associated waste management regulations to allow for land application of digestates from RMADF's, Ontario has eased the regulatory burden to on-farm biogas producers and allowed more efficient biogas production through mixed feedstock operations.

The Government of Ontario is also creating a market for RNG through funding infrastructure projects and pilot schemes starting in 2017, as part of the Government of Ontario Climate Action Plan (Government of Ontario, 2016). Examples include:

- $15-$20M funding for a "pilot program that uses methane obtained from agricultural materials or food wastes for transportation purposes, with funding for commercial-scale demonstration projects."
- $75-$100M funding to establish natural gas and low- or zero-carbon fuelling stations with collaborative working between the Government of Ontario and the transport sector.
- $60-$100M to promote and enable low-carbon natural gas supply in industrial, transportation and building sectors, in accordance with the introduction of a requirement for a RNG content in supply systems.
- $20-$30M to reduce emissions from waste and work towards zero-waste and zero GHG emissions from the waste sector.

Case Study: Europe

The European biogas industry has developed rapidly in recent years; in 2009, the industry was experiencing a 20% year-on-year growth (AEBIOM, 2009). This rapid growth has been achieved due to a number of motivators and incentives. The potential of methane production through AD in Europe is high; in theory AD methane production could supply a fifth of Europe's natural gas demand (AEBIOM, 2009).

European Union commitments to reduce GHG emissions has led to the development of 'renewable energy action plans' for each member state which include numerous incentives to mobilise more energy from biomass. Favourable feed-in-tariffs and green certificates for renewable electricity generation are believed to be the key driving force behind the rapid and successful development of the biogas industry in Europe. Many feed-in-tariffs and green certificates incentivise biogas production from manure, green cuttings and crops. Other measures implemented by EU member states to encourage biogas production include incentives to increase the number of gas-driven vehicles, fair grid access for biomethane without connection fees, and integration of waste management benefits (AEBIOM, 2009). Financial support for infrastructure development such as biogas pipelines, upgrading stations, and heat networks to use heat from cogeneration plants has also been utilised to develop a successful biogas industry.

In addition to government-funded and -legislated financial incentives, technological advances (especially in biogas cogeneration plants) have further improved feasibility of biogas as a reliable and efficient source

of electricity generation (AEBIOM, 2009). The integration of relevant policies in agriculture, waste management and energy has proven to be a significant factor in the successful development of the biogas sector.

Another motivator for biogas in Europe concerns energy security. Europe relies heavily on natural gas imports with approximately 40% of European natural gas is sourced from within Europe (AEBIOM, 2009). Promotion of domestic energy sources reduces reliance on potentially unreliable imports.

Case Study: Washington State

Washington State has created specific regulations and exemption criteria for dairy manure anaerobic digesters from requiring a Solid Waste Handling Permit. The exemption is based on organic feedstock type and quantity being processed by the digester, and outlines specific requirements or activities needed to obtain an exemption.

For smaller digesters with no more than 5,000 gallons or 25 cubic yards of material on-site at any one time, the exemption specifies that no notifications, reporting or testing requirements are required (Washington State Legislature, 2013). This rule removes a large portion of potentially obstructive regulatory burden for small operations who may not have the capital funds to invest in regulatory approvals, while limiting the risks due to the operation scale.

For larger digesters processing greater than 5,000 and less than 50,000 gallons (or greater than 25 but no more than 250 cubic yards) or material on-site at any one time, more stringent rules apply. The digestate that is to be applied off-site must be tested periodically to ensure it meets quality standards for compost and fertiliser, or to send digestate to a suitable composting facility if further treatment is required (Washington State Legislature, 2013). Regulation of the digestate in this way increases farmer confidence in the digestate product and provides for a sensible regulatory and enforceable solution for digestate management. Land application of the digestate on-site requires a nutrient management plan from the farmer, in accordance with associated regulations and guidelines.

For digesters using livestock manure, whether sourced on-site or off-site, there are no limits on the volume of feedstock that can be processed at any one time, provided at least 50% of the feedstock is from livestock manure by volume, and that imported non-manure organic feedstocks are not greater than 30% of the total volume (Washington State Legislature, 2013). The digestate can be land applied on-site under conditions set out in a dairy nutrient management plan, approved by the Washington State Dept. of Agriculture, or if transported off-site, must meet the specifications outlined above; periodic testing, and further composting treatment if required.

The regulations also outline standards for storage facilities specific to agricultural operations, preventing odour issues and water contamination risks.

The process is made easier for the proponent through a clear regulatory procedure specific to on-farm digesters that takes into account the specific risks and processes involved with processing of small volumes or specific types of feedstocks. The proponent also submits an initial application to only two

agencies, as set out in **Error! Reference source not found.** below. A clearly laid out permitting procedure with initial involvement from only two agencies who coordinate with other agencies, lowers potential application costs to the proponent, and creates efficiencies within and between agencies to reduce permitting timelines.

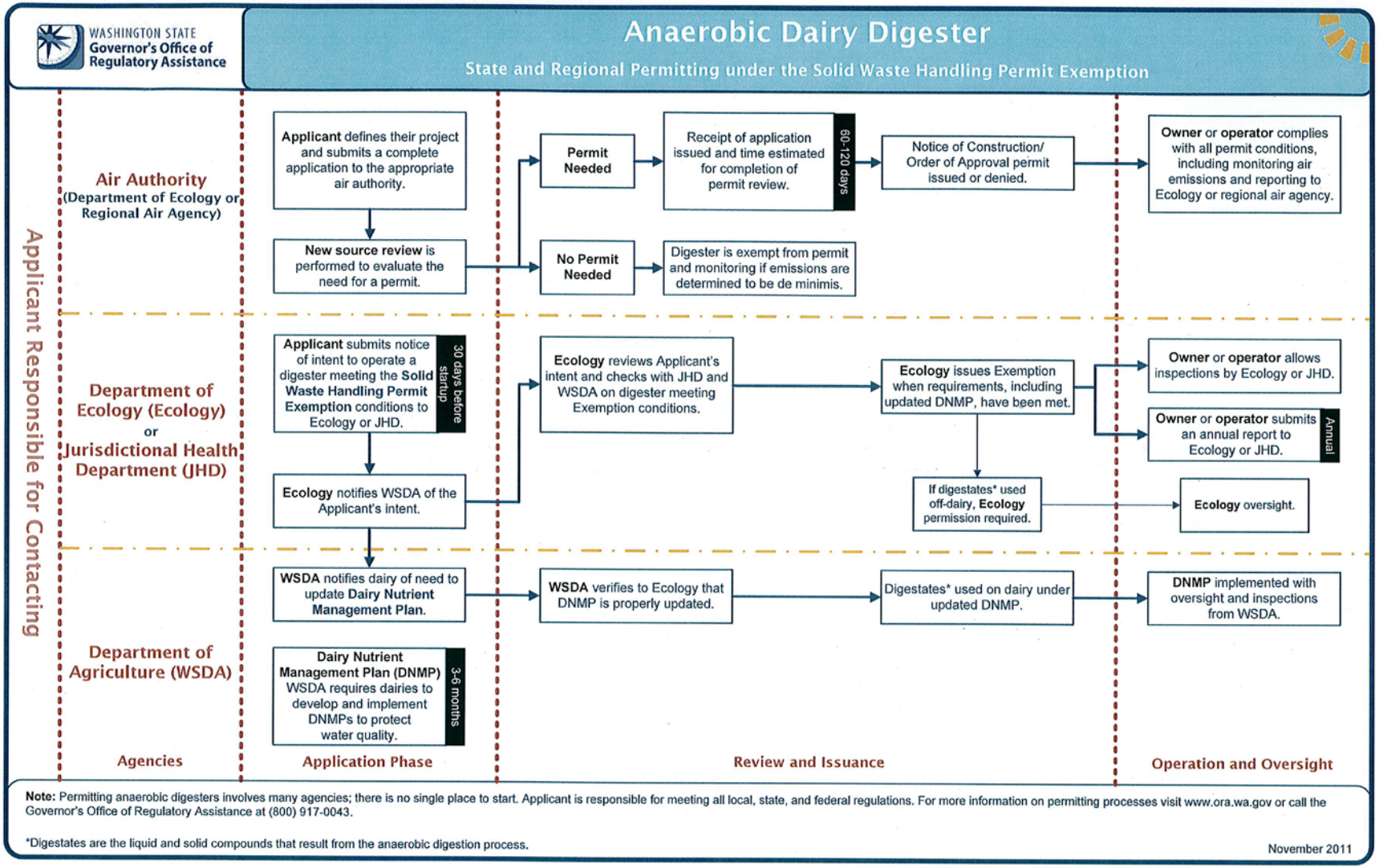


Figure 12: Washington State Anaerobic Dairy Digester Permitting Process

Appendix 3: Comparison of Renewable Electricity Programs

Table 15: Comparison of Biogas-Specific and Small Distributed Generator Renewable Electricity Programs

Factor	Bio Carve-out REP with Indexed REC System	Small Distributed Generator REP with Indexed REC System
Program cap or limitation	• A cap on the total capacity for the program would reduce the risk to GoA of substantial payouts. • A cap could restrict development of a full-scale biogas industry.	• The REP could specify a percentage of small renewable distributed generation from biogas projects. • Alternatively, the REP could allow open competition in a fuel neutral program while providing additional financial incentives for the non-energy (environmental / waste / nutrient management and GHG reduction) benefits of biogas. This could be complicated and difficult to implement.
Competition with conventional fuels and market access	• Would exclude competition with conventional fuel use while allowing market access for biogas electricity generation.	• Would exclude competition with conventional fuel use while allowing market access for renewable electricity generation, including biogas.
Competition with alternative energy	• Would eliminate competition with alternative energy technologies.	• Could allow for competition with alternative technologies if a minimum quota for biogas generation is imposed. • If a biogas quota is not imposed, other financial incentives for biogas would need to be included to allow biogas to compete with cheaper alternatives.
Regulatory and Permitting Environment	• Likely to enhance and streamline the regulatory and permitting process due to increased project proposals of a similar nature.	• Could enhance the biogas regulatory and permitting system depending on the amount interest generated and subsequent project proposals. • If the permitting process is not streamlined, the timescales involved could negatively impact biogas competition with alternative renewable technologies.
Competition between biogas developers to drive down costs and inspire innovation	• Fixed 'standing price' could be lowered periodically to drive down costs and stimulate technological and economic innovation.	• Would create some competition between developers especially if a quota for biogas is imposed and the cheapest producers selected. This type of competition would also motivate the creation of markets for non-energy products to maximise income. • However, competition could also select for certain operations such as landfill AD while restricting development where added benefits may be more significant, such

	• Competition between types of AD's and industries could be controlled through different standing prices for each.	as use of manure feedstocks. Added benefits and associated incentives would need consideration to avoid selection for certain projects. • If a biogas quota was not imposed, competition would be widened to include alternative technologies. How biogas developers could compete in this system would depend on the financial incentives given for the non-energy benefits of AD. Careful consideration of other financial incentives could select for certain projects, for example, those leading to the greatest GHG reductions.

Appendix 4: Workshop Participants and Other Expert Input

Alex Haye	InnoTech
Arifa Sutana	Environment and Parks, Bioenergy
Babatunde Olateju	Alberta Innovates
Brian Sexton	Alberta Environment and Parks
Chris Thrall	BioRefinex
Christian Felske	City of Edmonton
Don Roberts	Nawitka Capital Advisors Ltd
Elizabeth Shirt	ERA and Alberta Innovates
Glynis Frey	Alberta Agriculture and Forestry
Hong Qi	Alberta Agriculture and Forestry
Janelle Hancock	Alberta Environment and Parks
Jeff Bell	Alberta Economic Development and Trade
Leandro Tomei	Fortis Alberta
Lynda Skene	Independent
Lyndon Rempel	West Fraser
Mahdi Vaezi	University of Alberta
Pat Guidera	Alberta Innovates
Peter Woloshyn	Natural Resources Conservation Board
Raymond Lee	Alberta Utilities Commission
Sandy Fleming	Capital Power
Stefan Michalski	Lethbridge Biogas
Surindar Singh	Alberta Innovates
Susan McIntosh	Alberta Environment and Parks
Tom Goddard	Alberta Agriculture and Forestry
Victor Cheng	Alberta Agriculture and Forestry

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