Final Report

Feasibility of Producing Biogas into Gas Gathering Systems and Supplying Biogas Energy to Upstream Oil and Gas Facilities

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EXECUTIVE SUMMARY

This study evaluates the potential to improve the feasibility and utility of bioreactor projects in the agricultural and food processing industry, and to help reduce the capital investment needed to initiate these projects, through integration with the upstream oil and gas (UOG) industry. Bioreactors operating in Canada normally focus on using excess bio-energy onsite or producing electricity and selling it on the grid. Given the abundance and wide geographic distribution of UOG facilities in Alberta, there may be practicable opportunities to take advantage of this infrastructure or even supply bio-energy to nearby UOG facilities, for the mutual benefit of both parties. To evaluate this potential, detailed maps have been prepared showing, by geographic area, the likely feasibility of bioreactor projects based on the types and amounts of available feedstock. An extensive review of confined livestock operations, slaughterhouses and some secondary sources of bio-waste in Alberta was conducted. The demographics and intensity of UOG operations in the most favourable areas for biogas projects were then examined, and interviews with key UOG operators in these areas were performed to identify relevant technical, operational and contractual considerations.

The most viable biogas plants will occur where sufficient energy demand is available onsite, and more importantly, when meat waste disposal and manure spreading costs can be avoided. Where biogas projects are sustainable on their own merits and the produced biogas can be utilized onsite, there are no advantages to integrating with the UOG industry. The resulting connection and transportation costs tend to reduce the feasibility of the biogas project and do not offer any significant deferral of capital costs. Most of the capital costs of a biogas project are for the anaerobic digesters and feed preparation equipment. The incremental costs of any biogas processing and utilization equipment normally amount to less than 16 percent of the total capital cost.

The benefits of integrating a biogas project with the UOG industry are most significant where the produced biogas cannot be fully utilized onsite. This is most likely to occur for bioreactors associated with confined livestock operations due to their reduced demand for heat and electricity. Opportunities to integrate with the UOG industry in these situations will generally offer a positive benefit and should not be overlooked; however, the benefits gained are not likely to be sufficient to change the viability of a project that is not already sustainable on its own merits.

When insufficient onsite, energy demand is available the following UOG integration opportunity options were evaluated:

1. Production and sale of electrical power from biogas to nearby UOG facilities where interruptible power can be tolerated (e.g. to run pumpjack motors) or cost effective measures (e.g. redundant energy supplies) can address reliability issues.
2. Use of biogas as fuel at nearby UOG facilities to substitute or blend with fuel currently purchased from local gas co-operatives where little equipment modification is required.

3. Production of biogas into nearby UOG low-pressure gas gathering or multi-phase flow lines, and where downstream processing capabilities or dilution can reduce CO_2 concentration.

UOG industry representatives provided guidance on the technical and economic evaluation of each option.

The basic findings of this study are as follows:

1. Biogas production rates and economic opportunities are not equal from region to region in Alberta. The best biogas production opportunity areas are near meat processing plants and the maximum economic benefit occurs when meat waste has a disposal cost. Accordingly, biogas plants will be most economically attractive when located close to Red Deer, Brooks, Lethbridge, Fort MacLeod or Calgary.

2. The optimal biogas plant maximizes methane yield and minimizes initial economic investment. Storage, mixing and reactor tanks represent the bulk of initial capital costs. Choosing shop fabricated tanks instead of more expensive field constructed tanks is an effective choice for minimizing total plant cost and improving economic acceptability for potential proponents up to medium sized applications (i.e. bioreactor volume up to 3400 m^3). Biogas production depends on the volume and type of feedstock supplied to the bioreactor. A good feedstock mixture for biogas production is equal parts meat waste and manure.

3. Maximum environmental and economic benefit is achieved when the biogas plant is considered a waste handling facility that disposes of manure and meat waste while producing clean water, liquid fertilizer, solid soil amendment and finally biogas. Typically, the most economic benefit is from avoided manure spreading and meat waste disposal costs, while excess bio-energy sales and avoided fertilizer purchase make up the balance (i.e., revenue from bio-energy sales is usually less than 30 percent of the total economic benefit).

4. Projected payout periods for a small-scale (i.e. 1700 m^3 bioreactor volume) biogas plant range from very good (i.e. three to four years) where optimal feedstock conditions exist to very poor (i.e. greater than twenty years) where manure is the only feedstock available. These payback periods are estimated based on commodity prices presented in Section 3.3

5. Direct GHG offset credits are a potential source of revenue but are not included in this economic analysis because their market is still maturing. Direct GHG credits generated by a small-scale bioreactor might range from 2000 to 5000 tonnes CO_2E per year. More offset credits are available as the ratio of manure to meat waste increases. Eligible offset credits can be obtained from the capture and combustion of methane generated from manure only. At this point, the credit eligibility of methane generated from meat waste is undetermined and

therefore, not included in the analysis. Nonetheless, indications are that prices in excess of $20 per tonne of CO_2E may not be unrealistic, and could have a significant positive impact on the economics of a biogas plant, provided the cost of registering and marketing these credits does not become excessive.

6. Biogas plants may have to pool with other GHG emission reducing projects to achieve the volume of credits desired by purchasers. Quantities greater than 100 kilotonnes of CO_2E may be required.

7. Biogas plants are most viable when all excess energy can be utilized by the owner and they are located close to adequate sources meat waste and manure.

8. When there is insufficient onsite energy demand, biogas plants could take advantage of existing UOG infrastructure to provide sustained energy consumption. UOG facilities are well distributed in the areas of biogas interest and little difficulty should be encountered locating practicable end users.

9. Producing electricity with a combined heat and power (CHP) unit is technically practicable, but supplying it to a dedicated group of UOG equipment presents reliability and contract challenges. UOG operators often receive monetary bonuses for meeting production objectives; therefore, little motivation exists for operators to switch to an intermittent power supply. Many of the power reliability concerns can be addressed by incorporating redundant fuel supplies into the CHP system, but an independent power producer can never guarantee the same level of reliability as the grid. Negotiating a mutually beneficial power purchase agreement given the potential disconnection penalties and desired green energy premiums could be difficult.

   The advantage of selling electricity to UOG facilities is that it provides an energy end use opportunity when onsite demand is insufficient. The revenue generated from electricity sales does justify a CHP unit instead of simply venting or flaring the biogas. However, the overall feasibility of this option is still primarily dependent on the feedstock available and their avoided costs not revenue generated from electricity sales.

10. Selling biogas as a fuel is technically practicable when blended with natural gas and used in process heaters. Use of biogas in internal combustion engines is not recommended due to seasonal variation of biogas supply. Supply of excess biogas is lower during winter months because waste heat recovery is not available and produced biogas is used to maintain optimum bioreactor temperature. A redundant fuel supply (e.g. co-op natural gas) is required to address the reliability and load matching concerns.

    This option provides an alternative energy end use opportunity but has a less attractive economic outlook than the previous option. Economic savings due to removing the CHP are lost when more expensive equipment for compression and intermediate storage are included. Projected payout periods increase by one to two years relative to the scenario where all the excess bio-energy is utilized onsite. However, the revenue generated from retail sales of biogas still justifies compression and storage costs instead of flaring or venting.

11. Producing raw biogas directly into low-pressure gathering systems or multi-phase flow lines is the technically simplest option. No redundant (or backup) energy systems are required, gas processing equipment is often available downstream and suitable pipelines are abundant. A disadvantage of this option is that excess biogas available for sale is subject to seasonal variation because waste heat is unavailable and biogas is burned to maintain optimal bioreactor temperature.

    Producing biogas into UOG pipelines and gas processing facilities eliminates H_2S and CO_2 removal duties from the biogas plant, but the additional cost of compression and intermediate storage combined with processing, transmission, distribution and marketing fees have a negative impact on the economic feasibility. Projected payout periods increase by one to two years relative to the scenario where all the excess bio-energy is utilized onsite.

These findings were derived from the evaluation of publicly available technical and economic information combined with previous bioreactor work completed by Clearstone Engineering Ltd. All information sources are identified and listed in the reference section. Manure data was obtained from the National Resources Conservation Board (NRCB). Meat waste data was obtained by phone calls to the various plants and provincial meat inspection records provided by Alberta Agriculture, Food and Rural Development (AAFRD). Data relevant to the UOG sections was obtained from the Alberta EUB Licensed Facilities Reports and the Pipeline Attribute File combined with data prepared for a previous Clearstone Engineering publication (CAPP, 2005).

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LIST OF ACRONYMS

AAFRD	Alberta Agriculture, Food and Rural Development
AD	Anaerobic Digestion
AIES	Alberta Interconnected Electric System
BA	Business Associate
BTU	British Thermal Unit
CAPP	Canadian Association of Petroleum Producers
CHP	Combined Heat and Power
EPA	Environmental Protection Agency
EPEA	Environmental Protection and Enhancement Act
EUB	Energy and Utilities Board
GHG	Greenhouse Gas
IPCC	Intergovernmental Panel on Climate Change
IRAP	Industrial Research Assistance Plan
LFE	Large Final Emitters
NGGIP	National Greenhouse Gas Inventories Programme
NRCB	Natural Resources Conservation Board
RDP	Rural Development Plan
SRM	Specific Risk Material
UOG	Upstream Oil and Gas

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Industry representatives contributing to this report are listed below:

- Lillian Delisle of Anadarko Energy Corp.
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- Daniel Nugent of Canadian Natural Resources Limited
- Dave Karg of Devon Canada Corporation
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- Ed Phillipchuk of Alberta Agriculture Food and Rural Development
- Mathew Machielse of Alberta Agriculture Food and Rural Development
- Rick Atkins of Alberta Agriculture Food and Rural Development
- Jim Jones Alberta Agriculture Food and Rural Development

1 INTRODUCTION

This study evaluates the feasibility of integrating biogas plants at agricultural and food processing facilities with relevant energy collection and utilization systems in the upstream oil and gas (UOG) industry. The overall aim is to identify integration opportunities that would provide meaningful benefits to both industries and help further promote the use of bio-treatment technology in Western Canada. The potential for practicable opportunities of this type is high considering the close proximity of most oil and gas installations to agricultural operations. Input from UOG companies has been used to guide the technical and economic evaluation, and identify the key constraints or barriers to be addressed.

Anaerobic digester technology and its application to Canadian agricultural industry are described in Section 2 along with some of the factors motivating this report. Section 3 discusses different aspects of biogas production in Alberta. Opportunity areas for sustainable biogas production ranging from excellent to unsustainable are identified. An analysis of feedstock availability and biogas economics is used to determine opportunity areas. Commodity prices and bioreactor size used in feasibility calculations are defined and justified in Sections 3.3 and 3.1 respectively.

The remaining sections evaluate the technical and economic opportunities presented when integrating with the UOG industry. Section 4 explores the sale of electricity to dedicated UOG equipment. Section 5 looks at the retail sale of biogas as a low BTU fuel to UOG facilities. While Section 6 evaluates the wholesale delivery of biogas into low-pressure gas gathering systems or multi-phase flow lines. The value of retail and wholesale biogas is estimated in Sections 5 and 6. Report conclusions are summarized in Section 7. Appendixes A and B provide more technical information relevant to Sections 4, 5 and 6.

2 BACKGROUND

The primary motivation for this study comes from Alberta's Rural Development Plan (RDP): A Place to Grow (Alberta Government, 2005), which calls for better management of water resources and waste streams. The plan refers to the impact of agricultural practices and identifies priority actions to sustain and enhance the quality of rural Alberta's environment:

> *"…agricultural practices in rural Alberta can and do have a direct impact on the quality of Alberta's land, air and water. More needs to be done to work with industries in their management practices to balance the importance of promoting economic development, expanding tourism and preserving the environment. Consistent with Alberta's new Water for Life strategy, action must be taken to make the best use of Alberta's water resources and ensure all rural communities have access to safe drinking water."*

The priority actions identified in the RDP include the following:

- Improve waste management practices to reduce the impact of waste and odour on communities.
- Develop best practices and implement pilot projects in cooperation with industry.
- Support the adaptation and use of technologies that improve waste management or reduce odours.
- Explore bio-energy as an option for handing waste products from crop and livestock production.

The aim is to turn the environmental liability of agricultural waste into an economic opportunity for rural areas. Anaerobic digestion of organic wastes to produce biogas and organic fertilizer is one technology that can accomplish this goal.

Biogas systems are relatively new to Canada, even though they are a proven technology in many countries around the world and are the best available technology for treating organic waste streams. Most of the applications currently being considered and implemented in Canada are custom large-scale systems that are too costly for individual family-based farms or co-operatives. This study evaluates viable opportunities to enhance the economics of smaller and medium-sized applications and thereby promote increased penetration of the technology. This will improve the cost-effectiveness of these operations and will promote environmentally responsible management of organic waste streams produced by the agricultural and food processing sectors.

2.1 Bioreactor Description

Bioreactors are an environmentally responsible technology that utilize anaerobic decomposition to manage organic waste streams at agricultural and food processing facilities. Anaerobic digestion (AD) is a naturally occurring process of decomposition and decay by which the organic matter is broken down into its simpler chemicals components under anaerobic conditions (US EPA, 2003). The received waste streams are converted to brown water, reduced solids and biogas. Biogas plants are typically composed of the following elements: feedstock handling; anaerobic digestion; biogas utilization; liquid and solid handling. The agriculture feedstock sources for biogas production are various manures, meat processing wastes and waste plant materials. This feedstock typically produces methane in the 55 to 70 percent range with the balance being mostly carbon dioxide and ppmv levels of hydrogen sulphide (US EPA, 2003). Produced biogas is saturated with water vapour at the temperature of the reactor.

2.2 Key Benefits and Commercial Barriers

The key benefits of a bioreactor are the conversion of solid and liquid waste streams into useful products, water quality control and odour control. They are most feasible where significant waste disposal costs are being incurred and the available feedstock gives maximum biogas yields. As well, certain economies of scale apply. The application of this technology provides an opportunity to diversify Canada's Agricultural industry while improving its environmental and economic performance.

The direct quantifiable economic benefits are avoided or reduced waste disposal costs, avoided retail natural gas and electric power purchases, value-added organic fertilizer and potential creation of greenhouse gas credits. In Canada, bioreactors are not usually justified solely on direct economic benefits. Social and environmental benefits such as rural development, odour control, reduced land and water nutrient loading and the reduction of greenhouse gas (GHG) emissions are also motivating innovative waste management practices (Alberta Environment, 2005). There are five bio-reactor projects currently underway in Canada. Table 2.1 presents the name, location, description, feedstock and products from each system.

The primary motivation for the projects presented in Table 2.1 is social and environmental responsibility, not economic gain. In each case, the project proponents were seeking a more sustainable response to waste management than current practices provided. Unfortunately, it is difficult to attach economic value to the odour reductions, water quality improvements and GHG emission reductions achieved. Therefore, many of these projects have relied on government assistance for their development and initial capital costs (Government of Ontario, 2005; Innovation Alberta, 2005; Environment Canada, 2004; and Ag-West Bio, 2005). Governments want to see more sustainable practices achieved in the agricultural and food processing sectors and, therefore, have supported some pilot biogas initiatives to help promote market uptake of the technology. Biogas plant operators are now endeavouring to maximize the benefit from all potential product streams (i.e. heat, power, organic fertilizer, and GHG credits) and realize economic savings from avoided costs (manure disposal, dead animal disposal, etc.) to make their projects economically sustainable.

Table 2.1: Canadian Biogas Projects				
Owner	**Location**	**Project**	**Description**	**Specifications**
Highland Feeders LTD.	Vegreville, Alberta	Integrated Manure Utilization System (IMUS)	AD of cow manure to generate biogas, bio-fertilizer and reusable water. Biogas is used to generate electricity and heat for consumption on site and external sales. Power is generated during peak demand to obtain maximum revenue from electricity.[1]	*Feedstock:* -manure from 7500 head cattle *Products:*[2] -800 kW power -1050 kW thermal -bio-fertilizer (dry) (N:P:K 3%:2%:2%) -9.25 kt CO_2e/yr
Iron Creek Hutterite Colony	Viking, Alberta	Iron Creek Anaerobic Digester	European designed AD uses manure from an intensive livestock operation to produce biogas, water and soil amendment. Heat and electricity generated is used by the colony with the excess power sold to the Alberta grid. Requires about 45 minutes per day for maintenance and manure handling.[3]	*Feedstock:* -20000 hogs (about 88 m^3 manure slurry/day) *Products:*[3] -350 kW power -heat for hog barns -reusable water -solid soil amendment
Cook Feeders LTD.	Tevlon, Manitoba	Low temperature anaerobic treatment of hog manure and transformation of biogas into green energy[4]	The goal of this system is to minimize social and environmental impacts from surface and groundwater contamination; odour emissions and greenhouse gas emissions (N_2O) from hog manure spreading. The patented process was designed specifically for cooler Canadian climates and achieves AD between 15° C and 25° C. Heat generated from biogas is used for farm space heating and domestic hot water.[4]	*Feedstock:* -manure from 600 sow operation *Products:*[5] -potential electricity generation is 400 MWh/yr -potential heat recovery for use at farm -bio-liquid fertilizer -1.8 kt CO_2e/yr[1]
Clear-Green Environmental Inc	Cudworth Pork Plant (190 km's east of Saskatoon)	Clear-Green Anaerobic Digestion and Post Treatment Technology	This system is a commercial demonstration project that uses AD technology to produce biogas and organic fertilizer. SaskPower has installed turbines to produce heat and power using biogas. Thermal energy is sold to the neighbouring hog operation. Additional revenue is generated by charging a tipping fee for manure and selling organic fertilizer.[1]	*Feedstock:* -manure from 1200 sow operation *Products:*[1] -120 kW power -heat sold to hog operation -organic fertilizer -2.5 kt CO_2e/yr

Table 2.1: Canadian Biogas Projects				
Owner	**Location**	**Project**	**Description**	**Specifications**
Lynn Cattle Company Inc	Lucan, Ontario	Lynn Cattle Turnkey Integrated Manure Processing Plant (T.I.M.)	Cow manure will be processed in an anaerobic digester to produce biogas; water; and biologically stable, odourless and pathogen free fertilizer. The water will be recycled on the farm while the biogas will be used to produce electricity and heat.[1]	*Feedstock:* -manure from 5500 head beef operation *Products:*[1] -7000 MWh/yr power -heat used on farm -organic fertilizer -26.5 kt CO_2e/yr

[1] Monreal C et al, 2004
[2] Li X, 2005
[3] West D, 2004
[4] Environment Canada, 2004
[5] Wells G, 2005

The key barriers to widespread commercialization of the technology are the lack of familiarity with the technology by industry, the widely dispersed nature of the current agricultural and food processing applications, and the significant capital costs of installing bioreactor systems. Also, biogas plants have often been evaluated as a revenue generator and not as a cost saver, thus key economic opportunities may have been missed. Operational challenges include: anaerobic digestion start-up time, minimal reduction in waste volume and the marketing of unfamiliar products (i.e. green energy and organic fertilizer).

It is clear from a preliminary evaluation of the matter that a typical family-based farming operation is too small to support the capital costs of a bio-reactor system. Co-operative arrangements will need to be established.

Where the amount of biogas produced exceeds onsite demands for the production of useful heat or electric power, alternative options for utilization of the surplus gas are needed. Some of the potential opportunities that may arise from interfacing with the upstream oil and gas industry are as follows:

- Wholesale marketing of the biogas where it can be easily produced into a nearby low-pressure gas gathering or multi-phase flow line, and where either adequate in-line dilution or downstream processing capabilities are available to accommodate the high CO_2 content of the biogas.
- Retail marketing of biogas to nearby oil and gas installations that are currently purchasing propane or natural gas from a local gas co-op, and where biogas can be used as a substitute for these fuels with little or no adjustments/modifications to the end-use equipment.
- Retail marketing of biogas-produced electricity to nearby oil and gas facilities where either the potentially interruptible nature or reduced reliability of this power supply can be tolerated (e.g., to run pumpjack motors), or cost effective

measures can be taken to address any reliability issues (e.g., provide a supplemental fuel supply such as natural gas from a local gas co-op or diesel if a multi-fuel engine is installed).

Consultation with industry representatives was pursued to help evaluate the stated opportunities. Input was provided by experts from Anadarko Energy Corp; ConocoPhillips Canada Resources Corp; Canadian Natural Resources Limited; Devon Canada Corporation; EnCana Corporation, and Keyera Energy. Such companies may benefit from helping to support biogas projects through improved relationships with local landowners, possible access to lower-priced energy and the potential for GHG offset credits. However, at least one company noted there is little GHG motivation for participating until the Canadian Government finalizes its domestic GHG Offset System.

3 OPPORTUNITY FOR BIOGAS PRODUCTION IN ALBERTA

Sufficient waste feedstock for optimum biogas production and the most attractive economic return exists in the green zones of Figure 3.1. Maximum economic benefit can be achieved in green zones by locating the bioreactor beside a meat processing plant to avoid meat waste disposal costs and retail energy purchases. All of the excess energy from the bioreactor can be supplied to the meat processing plant, therefore, no additional energy demand is required so UOG opportunities were not investigated in these zones.

In areas where less meat waste is available and the feedstock is mostly manure, maximum economic benefit is achieved by locating the bioreactor beside a confined feeding operation. Orange and yellow zones in Figure 3.1 represent areas with practicable opportunities for bioreactor installations but additional energy demand is required. Typically, feeding operations do not have adequate or continuous energy demands that can utilize all of the excess bioreactor energy. Therefore, UOG opportunities were only investigated in yellow and orange zones.

The following sections elaborate on these findings.

3.1 Opportunity Zone, Feedstock and Bioreactor Description

A map of Alberta divided into grid cells of 0.5° latitude by 0.5° longitude, showing the areas of biogas opportunity by colour code is presented in Figure 3.1. The colour codes are defined in Table 3.1.

Table 3.1: Biogas Opportunity Codes

Zone	Biogas Generation Potential	Environmental Benefit	Energy End User	Waste Resource Availability[1]
Green	Excellent	Good	Meat Plant	>750 t/month meat waste >750 t/month manure slurry
Orange	Good	Good	UOG Facility *or* Meat Plant	~200 t/month meat waste[2] >1750 t/month manure slurry
Yellow	Moderate	Good	UOG Facility	~70 t/month meat waste[2] >1900 t/month manure slurry
Pink	Poor	Good	UOG Facility	>2000 t/month manure slurry

[1] Data sources: NRCB, 2005; Clearstone Engineering, 2005; and AAFRD, 2005b
[2] Accounts for potential meat waste delivered from two adjacent zones

The quality of biogas opportunities in each grid cell was assessed based on the availability of appropriate manure-slaughterhouse waste sources. The numbered grid area is also known as the “White Zone” of Alberta where agricultural production occurs and represents land that is vulnerable to nutrient loading, pathogens and odour from livestock production (AAFRD, 2005a). In this manner, opportunity areas address both environmental liabilities and biogas potential.

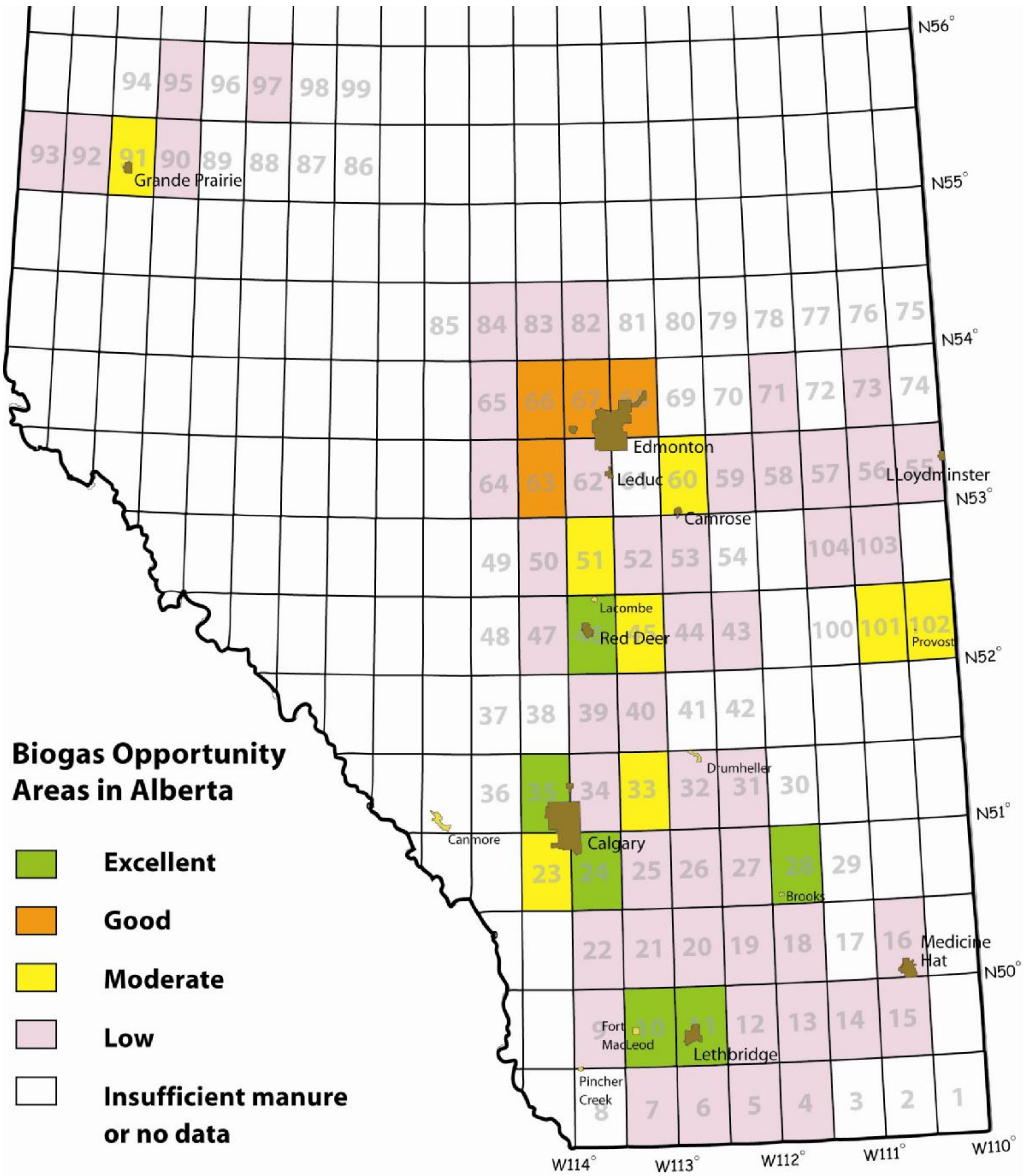

Figure 3.1: Biogas Production Opportunity Areas

Each grid area is approximately 1900 km^2. This grid size is chosen so that hauling of waste and product streams within each grid area would likely not exceed 20-30 km's. Each area numbered in Figure 3.1 is evaluated on its ability to sustainably produce biogas, based on a small-scale bioreactor design (Clearstone Engineering, 2004).

A single, small-scale, bioreactor design was chosen to minimize the economic and technical variables associated with this study. By fixing the reactor volume, the emphasis of this study could focus on feedstock mixtures and the feasibility of interfacing with the UOG industry. The chosen design is used because it endeavours to achieve the smallest possible, economically feasible system using Canadian economic and waste stream conditions. Details of this bioreactor are presented in Table 3.2. The small-scale design incorporates a number of less expensive, shop-manufactured tanks (570 m^3) to provide mixing, reactor and effluent handling services. With three tanks, this system can achieve a reactor volume of 1700 m^3. Larger systems are possible and may provide better economy of scale but feedstock collection and effluent distribution become more complicated, requiring more sophisticated management systems. A reactor volume of 1700 m^3 is considered a suitable choice for feasibility decision making because it minimizes the capital investment and waste management burden while producing useful volumes of biogas.

In addition to basic services provided by the biogas plant (e.g. waste disposal and fertilizer production), a CHP system (to produce electricity and recover waste heat) and reverse osmosis unit (to produce clean water) are included in the biogas plant to be evaluated in this section. These items deliver additional environmental benefits (i.e. low-impact renewable energy and clean water) with only a modest increase in capital cost. A comparative analysis of the economic investment required for environmental benefits is conducted in Section 3.3.4. Material costs and process flows used in the evaluation of the small-scale biogas plant are based on a preliminary bioreactor design completed under Natural Resources Canada's Industrial Research Assistance Program (IRAP) (Clearstone Engineering Ltd, 2004).

Table 3.2: Small-Scale Bioreactor Characteristics

Biogas Plant Characteristics	**Description**
Type of Reactor	Above ground, metal shell, pump mixing
Reactor Volume (3 tanks)	1700 m^3
Total Footprint	3.6 acres
Construction method	Modular Shop Fabrication
Retention time	20 days
Energy Output	Electric power Process heat
Other Products	Clean water Liquid fertilizer Solid Soil Amendment

Various agricultural, food processing and meat industry waste streams were considered as potential feedstock sources for the bioreactor. The most suitable sources are available year round, have good methane generation potential and have an associated disposal cost. The two main waste streams included in the feasibility calculations are:

- Manure from confined feeding operations for poultry, hogs, beef and dairy animals (NRCB, 2005)
- Meat waste[1] from typically smaller slaughterhouse facilities plus paunch material that is unusable by rendering facilities (AAFRD, 2005b; Clearstone Engineering Ltd, 2005). Meat waste from large slaughterhouse facilities is not included because it has a very low disposal cost and, therefore, little economic benefit for a biogas facility.

Other potential feedstock was investigated, including: fish processing waste, food processing waste, dead livestock, municipal waste, silage and crops. These feedstock sources are not included in the study due to their low or seasonal volumes, low methane potential or inherent economic value. However, given the right volume and economic conditions, these waste sources could be included in the bioreactor co-substrate.

3.2 Optimal Biogas Plant Locations

The green zones shown in Figure 3.1 represent areas where practicable applications for installing bioreactors at slaughter houses exist, and sufficient manure is available to allow optimal waste feedstock blending to achieve maximum biogas production. These situations offer the maximum potential economic benefits. Typically, the slaughterhouse waste would represent approximately half of the feedstock volume, thus a large economic benefit can be expected from avoided meat waste transportation and disposal costs. Slaughterhouse facilities also have sustained demand for large amounts of electricity and heat. Therefore, it is expected that excess heat and power produced by the bioreactor would be used by the slaughterhouse facility and alternative markets would not be required. Thus, UOG opportunities were not investigated for green areas.

Yellow and orange zones typically represent areas where practicable opportunities to install bioreactors near confined livestock operations exist. Manure from these facilities would represent most of the feedstock volume, thus the best economic benefit will come from avoided manure disposal and fertilizer transportation costs. Typical farm operations do not have large, sustained energy demands; therefore, alternative markets for surplus biogas or biogas-produced energy would be required. Thus, yellow and orange zones offer the best opportunities for potential biogas utilization by the UOG sector.

Pink zones are considered to have relatively low methane generation potential because only manure feedstock is available. Unless the phosphorus and nitrogen content can generate revenue as a fertilizer, the estimated payback period in these zones is considered too long for most farmers (i.e., greater than 20 years). Installing large-scale centralized bioreactors may improve the project economics but the initial investment increases

[1] Meat waste includes inedible offal and non SRM material.

tremendously and transportation logistics become difficult. Therefore, UOG opportunities for biogas utilization were not investigated in pink zones.

3.3 Economics of Biogas Production

The projected payback period for biogas plants located in green zones is about 3 to 4 years. As the potential to avoid meat waste disposal costs and produce excess biogas decreases the projected payout period increases. Consequently, the estimated payout period increases to 7 to 9 years in orange zones and 12 to 14 years in yellow zones. Pink zones have an unattractive payout period. These values include a 4.5 percent interest rate. However, they do not include the sale of GHG credits which have the potential to reduce payout periods by up to 6 years depending on the operation zone (a net value of $11.25/tonne CO_2E is assumed).

The following economic discussion is based on the small-scale bioreactor described in Table 3.2 and feedstock available in orange zones (see Figure 3.1). The orange operating zone was chosen because it highlights both the economic challenges and opportunities encountered by a typical small-scale biogas plant. The small-scale biogas plant was chosen because it requires less capital investment and is best suited to maximize the benefit from small volumes of meat waste.

3.3.1 Ownership

Ideally a biogas facility will have more than one stakeholder. Given that the feedstock will usually need to come from multiple sources to achieve a reasonable economy of scale and the products are valuable to more than one user, a co-operative ownership structure will help facilitate the long term sustainability of each project. Table 3.3 outlines potential stakeholder roles and expected benefits for each application. In addition to the stakeholders identified in Table 3.3, support from provincial and federal governments may be required to offset the high capital investment required for a biogas plant and to further stimulate interest in the technology by providing initial demonstration projects to showcase profitable applications. Local circumstances at candidate sites will ultimately decide the most suitable stakeholders and their respective roles.

Table 3.3: Stakeholder Roles			
Stakeholder	**Feedstock Supply**	**Product Use**	**Social and Environmental Benefits**
Farmer	Manure	-Fertilizer -Clean water -Disposal service	-Odour Control -Water conservation
Meat Processing Plant	Meat waste	-Disposal Service -Process heat -Electricity -Clean water	-Green project recognition
UOG	-	-Raw gas, sales gas, or electricity -GHG credits	-Synergy with rural land owners -Green project recognition
Municipality	Other organic waste streams	-	-Economic diversification -Odour control -Water conservation

3.3.2 Revenue and Avoided Costs

To achieve an economically sustainable bioreactor, all potential revenue streams and any avoided operating costs must be realized and accounted for. Activities that could economically benefit a biogas plant and their anticipated avoided costs are presented in Table 3.4. These values are used to estimate the net economic benefit and projected payout period of a biogas plant. Commodity prices represent what stakeholders might be expected to pay in the absence of a biogas plant. Figure 3.2 illustrates the relative importance of each activity.

Table 3.4: Biogas Plant Product Utilization – Commodity Prices	
Activity	**Avoided Cost**
Meat Waste Disposal[1]	\$70/tonne
Manure Spreading[2]	\$5.85/m^3
Electricity Purchase	\$70/MWh
Natural Gas Purchase	\$10/GJ
Fertilizer Purchase	N: \$578/tonne P: \$616/tonne K: \$328/tonne
Water Purchase[3]	\$1.09/m^3
Transportation Costs[4]	\$1.00/m^3

1 Meat waste disposal cost varies depending on the volume of waste and location of the meat processing plant. Costs range from zero to \$150/tonne for small plants in remote areas.

2 Manure spreading costs represent equipment and labour expenses associated with typical manure utilization on farms. \$5.85/m^3 manure represents the lower bound of this cost.

3 Water costs depend on local availability and/or transportation distances. Water prices range from \$1.09/m^3 to \$2.50/m^3.

4 Transportation costs savings are incurred relative to normal manure handling practices. Savings range from \$1.00 to \$2.50 per cubic meter of liquid effluent produced.

Figure 3.2 depicts the distribution of economic benefit from the biogas plant described in Table 3.2 operating in an orange zone. The plant handles about 1750 tonnes of manure and 200 tonnes of meat waste per month and produces about 3000 m^3 of biogas per day. Figure 3.2 shows that the avoided cost of meat waste disposal and manure spreading represents almost 60% of the total economic benefit, while, heat and electricity only represent 27% of the benefit. Fertilizer, transportation and recycled water benefit make up the balance.

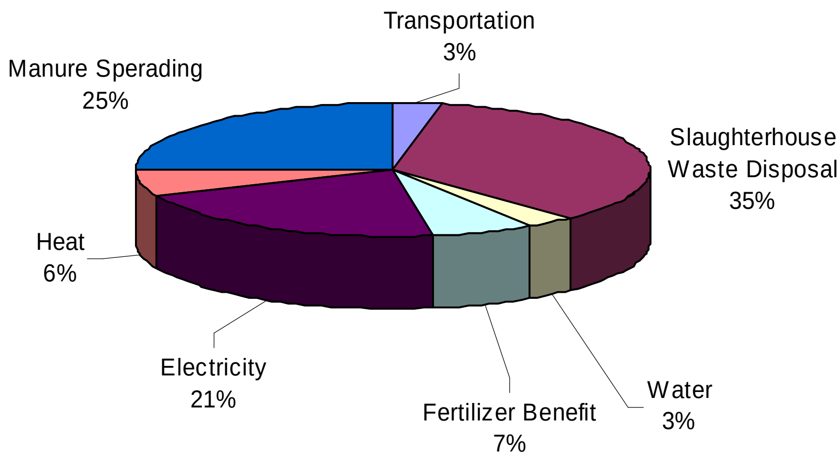

Figure 3.2: Distribution of Economic Benefit from a Biogas Plant

The revenue generated from avoided retail purchase of electricity and gas normally represents only a small portion of the total net economic benefit. Still, the incremental benefit from combined heat and power (CHP) generation justifies the associated capital costs. Economic benefits from avoided retail purchase of electricity and natural gas pays for the CHP system in 2 to 3 years.

An additional economic benefit for biogas projects is the potential sale of direct GHG offset credits. For example[2], approximately 5000 tonnes of CO_2E could be reduced annually from a 1700 m^3 bioreactor handling 1750 tonnes/month of manure (about a 1400 head cattle feedlot). This could represent 9 to 12 percent of the total economic benefit presented in Figure 3.2 and should be pursued when the Canadian Offset System is finalized (Government of Canada, 2005).

The business-as-usual national inventory for GHG emissions from manure handling is established by the IPCC. Default emission factors available for

[2] In the absence of a Canadian GHG Protocol for biogas plants, estimates for the GHG offset potential are based on Intergovernmental Panel on Climate Change (IPCC) documents (IPCC, 1996; IPCC-NGGIP, 2000)

calculating the agricultural contribution to national GHG inventories are equivalent to the emission factors encountered when using anaerobic digesters to dispose of manure waste. That is, it can be assumed that all the methane generated from manure within the bioreactor and converted to CO_2 is eligible for direct GHG offset credits. If methane was not captured by the bioreactor it would already be accounted for in the national GHG inventory. At this time, methane generated from meat waste is not included in GHG calculations because no protocol has been established.

High quality GHG credits are being sold for more than \$20/tonne CO_2E on European markets (Point Carbon, 2005). The value of credits generated in Canada is expected to migrate toward European prices as the Kyoto compliance period approaches (e.g. 2008 to 2012). For now, a gross value of \$15/tonne of CO_2E is used to estimate the potential economic benefits from GHG credits. The Canadian Government has also chosen this value and has pledged to cover Large Final Emitters (LFE) compliance costs exceeding \$15/tonne CO_2E (Environment Canada, 2005). A large degree of uncertainty will remain with the value of Canadian GHG credits until the federal government finalizes reduction plans and compliance mechanisms. Administration fees equivalent to 25 percent of the gross credit value could be justified for the application, verification, registration and sale of GHG credits. Project proponents can expect to incur buying, selling, legal, and marketing fees similar to real state transactions in addition to engineering and accounting fees for auditing and verification programs. Therefore, a net GHG credit value of \$11.25/tonne CO_2E (i.e. \$15/tonne CO_2E minus 25%) is taken for this report.

3.3.3 Estimated Payout Period

Initial capital investment for a small-scale biogas plant managing 2000 tonnes of waste per month, which maximizes benefits as described in Table 3.6, is estimated at approximately \$3.2 million. Based on the feedstock availability in Figure 3.1 and current material costs and energy prices; the estimated payout periods are presented in Table 3.5 for each opportunity area. The presented estimates assume all of the economic benefits identified in Table 3.4 are realized, transportation costs are minimal and no major operational problems are encountered. These estimates are subject to fluctuations in commodity prices and operational problems encountered at the biogas plant.

Table 3.5: Estimated Bioreactor Payout

Opportunity Area	Estimated Payout (4.5% Borrowing Rate)
Green	3 to 4 years
Orange	7 to 9 years
Yellow	12 to 14 years
Pink	Greater than 20 years

Potential GHG offset credit revenue is not included in this analysis because there is too much uncertainty associated with the price of GHG credits. If direct GHG offset credits are sold for $11.25/tonne CO_2e and included in the estimates presented in Table 3.5, projected payouts would decrease by 4 to 6 years in pink zones, 1 to 3 years in yellow zones, 1 year in orange zones and would have little impact in green zones. GHG credits are much more valuable to operators in pink zones because all of the biogas is derived from manure and GHG revenue is a more significant part of the total revenue.

This economic evaluation indicates that biogas economics are very good in green zones and this alternative waste management strategy should be attractive to both the meat processing and livestock industries. Orange and yellow zones present less attractive economic incentives, which shifts the motivation for a bioreactor to social and environmental benefits not economic gain. Pink zones have a very unattractive economic outlook and will require government support to achieve sustainability. Sections 4, 5 and 6 endeavours to identify other benefits and economic opportunities associated with supplying biogas energy to the upstream oil and gas industry in orange and yellow zones.

3.3.4 Incremental Cost/Benefits of Bioreactor Systems

Table 3.6 presents the incremental costs and benefits associated with bioreactor improvements for a fixed volume reactor (e.g. 1700 m^3) with a mixed feedstock of 10 percent meat waste and 90 percent cow manure. The table shows how environmental benefits relate to their economic cost and projected payout period. That is, how does the economic outlook for the entire plant change as biogas utilization and water purification equipment are added and environmental benefits improve? Also, the payout period for each equipment component is presented to demonstrate how individual revenue streams can payoff additional equipment costs.

The incremental cost increase associated with improved environmental performance is relatively small. The basic 1700 m^3 bioreactor in Table 3.6 has an initial cost of $2.67 million. Adding equipment to provide clean water, heat and power increases initial cost by 16 percent to $3.17 million and improves the payback period by two years for the mixed feedstock scenario. Adding a reverse osmosis unit to treat the liquid effluent and provide clean water has a high capital cost relative to the economic benefit it delivers. However, it has little impact on the overall economic picture because its contribution to the total capital cost is still relatively small. The bulk of biogas plant capital cost is tied to the processing tanks.

Table 3.6: Incremental Benefits for a Bioreactor with Mixed Feedstock				
Biogas Plant Description	**Capital Cost Ratio**[1]	**Benefits**[2]	**Mixed Feedstock**[3]	
			Component Payout Period (years)[4,6]	Entire Plant Payout Period (year)[5,6]
Basic Bioreactor (tanks, feed handling, effluent handling and flare)	1	-manure and meat waste disposal -fertilizer production	10	10
Bioreactor with heating (e.g. boiler)	1.071	-Process heating -manure and meat waste disposal -fertilizer production	2	7
Bioreactor with heat and power (e.g. CHP system)	1.075	-electricity and process heating -manure and meat waste disposal -fertilizer production	2	8
Bioreactor with water treatment (e.g. reverse osmosis unit)	1.114	-clean water -manure and meat waste disposal -concentrated fertilizer production	13	10
Bioreactor with heat, power and water treatment (e.g. CHP system and reverse osmosis unit)	1.189	-clean water -electricity and process heating -manure and meat waste disposal -concentrated fertilizer production	4	8

1 Ratio of incremental capital cost to basic bioreactor cost. Initial investment for basic bioreactor is estimated at $2.67 million.
2 Incremental benefits achieved as additional equipment is included in biogas plant.
3 Economic analysis based on feedstock of 10 percent meat waste and 90 percent cattle manure.
4 Projected payout period of additional equipment is based solely on the revenue generated by the additional equipment. Interest rate is set at 4.5 percent.
5 Projected payout period for entire biogas plant based on combined revenue of the plant. Interest rate is set at 4.5 percent.
6 Payout periods based on commodity prices presented in Table 3.4.

3.4 Approvals Required

The bioreactor is considered a waste management facility and requires approval from Alberta Environment under the Environmental Protection and Enhancement Act (EPEA). It is identified as such under the Activities Designation Regulation in Schedule 1, Division 1, Clause C (Alberta Government, 2003):

> *"the construction, operation or reclamation of a facility for the collection and processing of waste or recyclables to produce fuel, where more than 10 tonnes of waste or recyclables per month are used to produce the fuel."*

The "Guide to Content of Industrial Approval Applications" is a useful reference when identifying required content for the application to construct and operate industrial facilities. Submitted applications are reviewed by Alberta Environment staff and approved by a Director subject to the Alberta Environmental Protection and Enhancement Act (EPEA) (Alberta Environment, 1999).

Before the liquid bi-product can be applied to fields as a fertilizer it would have to meet effluent criteria outlined in the Guidelines for Municipal Wastewater Irrigation document. This document endeavours to assess effluent quality, suitability of land for wastewater irrigation, loading rates and crop suitability to ensure irrigation is agriculturally beneficial and environmentally acceptable (Alberta Environment, 2000).

Additional approvals and licenses are required depending on the energy end use scenario. These are discussed in Sections 4, 5 and 6.

4 PRODUCTION OF ELECTRICAL POWER FROM BIOGAS FOR USE AT NEARBY UOG FACILITIES

Production of electricity from biogas and its sale to UOG facilities has little impact on the economic feasibility of a biogas plant. The revenue generated is roughly equivalent to that from avoided retail purchase of electricity. Plus, the cost of additional equipment for control and transmission of electricity are insignificant relative to the total project cost.

The most suitable equipment candidates to consume the electricity are well site pumpjacks. A large number of pumpjacks are located in the selected biogas opportunity areas. However, significant technical barriers are encountered when evaluating this option. The key barriers include complicated power purchase agreements and the potential to interrupt hydrocarbon production. A description of the proposed system as well as technical and economic factors considered is presented in the sections below.

4.1 Description

Given the large number, and wide geographic distribution of electricity consuming facilities in the UOG industry, there is a reasonable likelihood for suitable UOG electricity demand to exist in the vicinity of potential biogas plants. Electricity generated at a biogas plant could be transmitted on independent power lines at 480 or 600 volts to a small group of dedicated UOG equipment. Appropriate UOG equipment includes only those that could operate independently of the Alberta Interconnected Electric System (AIES) and acceptably run on intermittent power (i.e. electrically driven pumpjacks). The biogas plant would need to be responsible for ensuring the reliability and quality of the power supply.

The bioreactor described in Table 3.2 could produce enough biogas to generate between 150 kW and 200 kW of electricity depending on the nature of feedstock supplied. Biogas volume decreases as the meat waste decreases. 200 kW of electricity would be available from a plant processing 200 tonnes/month of meat waste (about 750 cattle kills per month) and 1750 tonnes/month of manure (about a 1400 head cattle feedlot). While, 150 kW of electricity would be available from 80 tonnes/month of meat waste (about 300 cattle kills per month) and 1900 tonnes/month of manure (about a 1500 cattle head feedlot). The power supply should not vary with changing ambient conditions.

Recovered heat from the CHP system would be used to maintain the bioreactor at 35° C (i.e., the value required for optimal mesophilic digestion). Most of the year, waste heat from the engine would be sufficient to satisfy the bioreactor heat demands with excess heat available for space heating. Waste heat recovery is an advantage this option has compared to the other fuel utilization scenarios. Instead of burning biogas to maintain the bioreactor temperature, the system takes advantage of low grade waste heat. Although, when winter conditions are encountered and the temperature drops below -10°C, additional natural gas may be required to meet bioreactor heat demands. Additional natural gas costs are accounted in all economic evaluations.

4.2 Technical Considerations

Connecting an independent power producer to a dedicated group of users poses a number of challenges making the feasibility of this option questionable. Several concerns were identified by UOG industry representatives from the companies listed in Section 2.2.

4.2.1 Key Technical Comments from UOG Representatives

Industry representatives were asked general questions about all three UOG energy utilization scenarios. Technical comments regarding the supply of electricity to UOG equipment include:

- A biogas plant is considered a new technology and would require many years of demonstrated reliability before wide spread acceptance is achieved.
- Equipment reliability is essential to operators. Often monetary bonuses are dependent on achieving hydrocarbon production objectives. Thus, there is little motivation for operators to switch from the AIES to an independent power producer that offers reduced reliability (i.e., there is concern that an independent power producer could not supply the same quality of power as the AIES).
- Concern that adequate power control and safety equipment would be installed to ensure operator safety and prevent equipment damage.
- Concern regarding obligations to current power providers and potential for disconnect penalties. Power purchasing contracts are notoriously complicated and require specialized personnel to negotiate and maintain these agreements. Introducing bio-energy into power contracts may further complicate the negotiations.
- Questions why distributed generation has not proliferated after considerable attention during last few years.
- Green power and improved landowner relations would be a valued project benefit.

Power reliability concerns can be partially addressed by incorporating a natural gas fuel supply in parallel to the biogas fuel supplied to the CHP unit. By adding redundancy to the fuel supply, a more reliable power source is achieved. However, the independent power producer is still vulnerable to unscheduled maintenance problems. Few facilities or equipment components in the UOG industry will tolerate an intermittent or alternative power supply when the AIES is available. Convincing UOG companies that a biogas plant can provide an adequate level of reliability is a significant barrier to this scenario

Including a redundant fuel supply improves the generators ability to load match. As the UOG electricity demand varies, due to equipment coming on or off line, the volume of natural gas supplied to the engine can also be varied. Biogas consumption would ideally supply base loads and therefore remain constant.

Establishing a mutually beneficial power purchase agreement is considered an onerous task. A few of the key issues to be negotiated include:

- Agreeing to an energy price that incorporates premiums for green power as well as compensates for reliability and power quality concerns.
- Distribution fees.
- Compensation to UOG companies for potential disconnection penalties.
- Premiums paid for GHG offset credits.
- Life expectancy of UOG demand versus biogas production.
- Metering requirements and responsibility delegation.

The administrative burden associated with such a contract may not be worth the anticipated benefits for either the UOG company or the biogas proponent.

CHP packages are designed to address most of the power quality and protection concerns raised. Generator over sizing and surge protection can accommodate demand spikes from equipment coming online (Cummings, 2005). Generators control voltage and frequency tolerance limits to within those indicated by the Alberta Distributed Generation: Interconnection Guide (Alberta Distributed Generation Technical and Policy Committee, 2002). H_2S concentrations must be reduced to 20 ppmv to meet engine fuel quality specifications. Power quality and safety concerns can be managed with proper design, operation and strict adherence to applicable standards and codes.

In addition to the local bylaw requirements and approvals outlined in Section 3.4; approvals for the electricity transmission line are required under EUB Directive 028. Exemption may be possible depending on local circumstances. Combustion equipment cannot produce emissions that exceed Alberta Air quality Objectives (Alberta Environment, 2005) or noise levels determined by EUB Interim Directive 99-8 (AEUB, 2004).

In general, most of the technical concerns raised by UOG representatives can be managed. However, the biogas plant will still be perceived as a new technology and reliability concerns coupled with complicated power purchasing contracts will present significant challenges. More details on electricity reliability, quality control, overload protection, metering and approvals required are presented in Appendix A.

4.3 Initial Economic Evaluation

The additional equipment costs associated with power control and transmission have little impact on the overall economic feasibility of biogas plants. Key assumptions and price estimates are provided below.

4.3.1 Key Economic Comments from UOG Industry Representatives

Economic comments regarding the supply of electricity to UOG equipment include the following:

- An economic incentive would be required to attract the attention of operators and motivate the switch to bio-energy. A 10 percent discount from current electricity rates was considered a sufficient incentive.
- Equivalent energy price to current rates may be easier to justify if biogas plant met the power demand of a new facility.
- Number of GHG credits available from the biogas plant may be too small to interest UOG companies.

4.3.2 Potential Revenue

UOG facilities pay for both distribution and energy costs. Both of these costs should be accounted for when determining the anticipated revenue generated by selling power directly to UOG facilities. Combining the current energy rate and distribution charges described in Section A.9 with a 10 percent discount yields a total energy rate of $0.08/kWh. This value is used to determine anticipated annual income from electricity sales to UOG facilities.

4.3.3 System Costs

Installing a combined heat and power (CHP) generator plus electricity control, metering and distribution equipment will increase the cost of a bioreactor plant. Cost provisions are included for the following:

- H_2S removal and monitoring facilities.
- A CHP generator and associated buildings.
- Electricity monitoring, metering, control and protection.
- A distribution line 1 km long.

The additional cost of electricity control and distribution equipment does not have a noticeable impact on the projected payout period relative to that presented in Section 3.3. Table 4.1 shows the incremental cost increase from power transmission lines is very small. In areas with good biogas opportunity (i.e. orange zones in Figure 3.1) the projected project payout remains between 7 and 9 years. In areas with moderate biogas opportunity (i.e. yellow zones in Figure 3.1) the projected project payout remains between 12 and 14 years. Interest rate is set at 4.5 percent.

Table 4.1: Incremental Cost/Benefit of Electricity Transmission				
Biogas Plant Description	**Capital Cost Ratio**[1]	**Benefits**[2]	**Mixed Feedstock**[3]	
			Component Payout Period (years)[4,6]	Entire Plant Payout Period (year)[5,6]
Basic Bioreactor (tanks, feed handling, effluent handling and flare)	1	-manure and meat waste disposal -fertilizer production	10	10
Bioreactor with heat and power Excess electricity used onsite	1.075	-electricity and process heating -manure and meat waste disposal -fertilizer production	2	8
Bioreactor with heat, power and electricity transmission Excess electricity transmitted to nearby UOG facility	1.094	-electricity sold to UOG and heat used onsite -manure and meat waste disposal -concentrated fertilizer production	2	8
Bioreactor with heat, power, water treatment and electricity transmission Excess electricity transmitted to nearby UOG facility and water used on farm	1.208	-electricity sold to UOG and heat used onsite -clean water -manure and meat waste disposal -concentrated fertilizer production	4	8

1 Ratio of incremental capital cost to basic bioreactor cost. Initial investment for basic bioreactor is estimated at $2.67 million.
2 Incremental benefits achieved as additional equipment is included in biogas plant.
3 Economic analysis based on feedstock of 10 percent meat waste and 90 percent cattle manure.
4 Projected payout period of additional equipment is based solely on the revenue generated by the additional equipment. Interest rate is set at 4.5 percent.
5 Projected payout period for entire biogas plant based on combined revenue of the plant. Interest rate is set at 4.5 percent.
6 Payout periods based on commodity prices presented in Table 3.4.

4.4 Proximity to Appropriate UOG facilities

Figure 4.1 shows opportunity areas for biogas-generated electricity to be used for pumpjack operation. The best opportunities exist in eastern Alberta near Provost. Pumpjacks are very common in Alberta and good opportunities also exist in the central corridor between Edmonton and Calgary.

An investigation of active wells in Alberta yielded a list of sites where active pumping wells exist. While it was not possible to determine which sites use electric motors to drive the pumps and which one use fossil-fuelled engines, the results still provide an indication of general areas of opportunity rather than specific candidate wells. The search was conducted using data from the year 2000, in areas where the biogas plant would likely be located on a farm and UOG facilities would be the end energy users. Data for this investigation was taken from previous investigations conducted by Clearstone Engineering (CAPP, 2005).

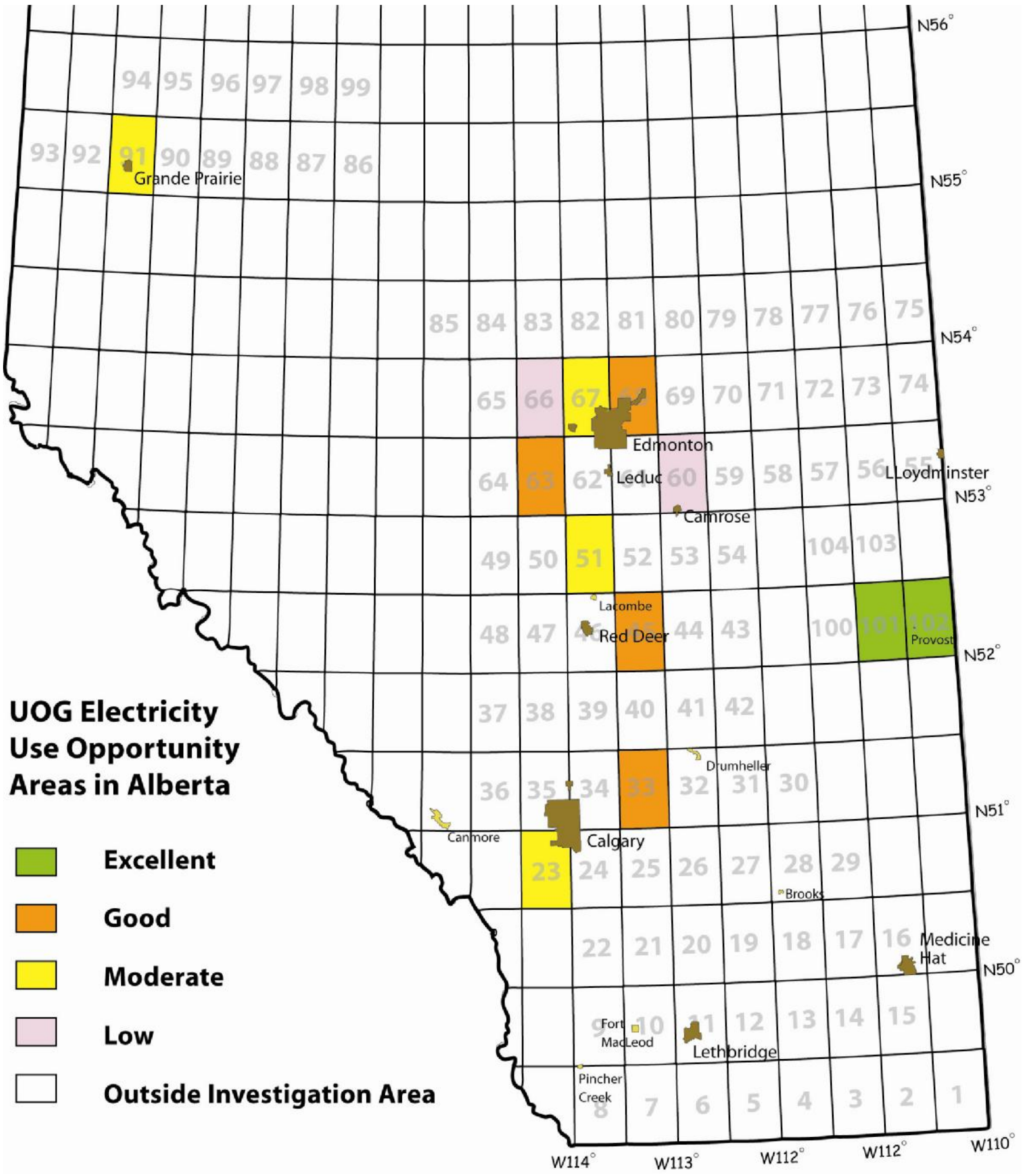

Figure 4.1: Biogas as Electricity: Opportunity Map

5 USE OF BIOGAS AS FUEL AT NEARBY UOG FACILITIES

Supplying biogas fuel for process heating at UOG facilities can be a practicable solution for ensuring adequate and continuous energy demand for biogas plants. There is little technical challenge associated with delivering biogas fuel to appropriate UOG equipment, but additional equipment requirements have an adverse impact on the economic feasibility. When biogas is consumed onsite for thermal or electric power generation, intermediate storage (i.e., an onsite biogas accumulator) and compression are not required. However, compression and storage cannot be avoided when the biogas is transported offsite. Revenue from biogas sales justifies additional equipment costs but it does not contribute enough to achieve the same projected payout period as that presented by the previous options. Payout periods increase by one to two years. Technical and economic factors considered as well as a description of the proposed system are presented in the subsections below.

5.1 Description

Produced biogas could be transported to appropriate UOG equipment using dedicated fuel lines. UOG equipment that may require sweetened fuel includes line heaters, emulsion treaters, glycol reboilers, pumpjack engines, compressor engines, etc. It is anticipated that biogas could supplement existing co-op gas supplies and would not exceed the lowest seasonal fuel demand. Likely equipment candidates would be those at sour facilities where sweet process gas is not available and retail purchases from a gas co-op are required. Where sweet process gas is available, it would have a much lower effective cost than either biogas or co-op gas[3].

The bioreactor described in Table 3.2 could produce between 2200 m^3/day and 3000 m^3/day depending on the feedstock mixture. The higher biogas production estimate is associated with a waste stream composed of 200 tonnes/month meat waste (about 750 cattle kills per month) and 1750 tonnes/month manure (about a 1400 head cattle feedlot). The lower estimate is based on a waste stream composed of 80 tonnes/month meat waste (about 300 cattle kills per month) and 1900 tonnes/month manure (about a 1500 cattle head feedlot). The bioreactor volume of 1700 m^3 was chosen because it is estimated to be the most economical size that delivers maximum benefit to project proponents.

Heating requirements to maintain the reactor at 35° Celsius consume part of the produced biogas and reduce the overall yield available for sale. The absence of waste heat recovery is a disadvantage of this option and adversely affects its economic feasibility. During cold winter months biogas available for sale may be as low as 600 m^3/day while summer months may yield as high as 2400 m^3/day.

[3] Operators pay approximately 12 percent of the Alberta Natural Gas Reference Price for fuel gas consumed (Alberta Government, 1994). This represents a cost of less than $1/GJ.

Biogas as fuel can be supplied to UOG facilities with two types of equipment: (1) internal combustion engines or (2) process heaters. The technical and economic merits of each option are explored in the following sections.

5.2 Technical Evaluation

Providing biogas as fuel to process heaters instead of internal combustion engines is preferable given seasonal supply variations and engine sensitivity to fuel heating values. Greater fuel flexibility can be achieved with process heaters. Technical challenges and opportunities are elaborated on after the comments from industry representatives.

5.2.1 Key Technical Comments from UOG Representatives

Technical comments regarding the supply of biogas fuel to UOG equipment include:

- Fuel gas is not always purchased from local co-operatives for sour facilities that do not have any onsite gas sweetening capabilities. Sweetened gas can be pipelined from the gas processing plant back to the upstream equipment. Some companies choose to supply all their own fuel.
- Blending biogas with natural gas from a co-op should satisfy reliability concerns. Common industry practise to blend solution gas with gas purchased from co-ops.
- Dry gas is required for use in engines. Concerns were raised regarding the potential formation of carbonic acid when water droplets and CO_2 are present in the same stream.
- Fewer opportunities exist to utilize biogas as fuel in process heaters because heaters are not as common as pumpjacks or gathering systems; however, on an individual basis, they will tend to have much greater average fuel demands.
- This is the easiest contract to negotiate of three energy utilization options considered. No penalties are anticipated for reduced consumption of co-op gas.

5.2.2 Option 1: Internal Combustion Engines

Many UOG facilities rely of internal combustion engines to drive mechanical equipment for producing and transporting oil and gas. These facilities include wellheads and compressor stations. It is theoretically possible to run these engines on a blend of biogas and natural gas but technical challenges arise. These include the following:

- Seasonal supply variations: Biogas supply will be subject to seasonal variations due to heating requirements of the bioreactor and variations in feedstock. Blending natural gas with biogas at the point of use will ensure adequate supply but it will also result in a wide range of fuel heating values supplied to the engine.

- Engine Setup: Most natural gas engines operate within a narrow range of fuel quality limits. When a lower energy content fuel (i.e. biogas) is introduced, the fuel to air ratio needs to be increased. Engine adjustments or replacements may be possible but subsequent operation of the engine is unlikely to be able to cope with continued variation in the fuel heating value.
- Interruptible gas supply: Biogas could be supplied to a single engine that was adjusted to run on low BTU fuel (approximately 20 MJ/m^3). However, the UOG operator would have to accept the interruptible nature of the biogas supply. Engine operation and well production would cycle depending on biogas availability and line pressure. Operational cycling would be more frequent and hydrocarbon production volumes would be lower during cold months.
- Moisture content and corrosion: UOG operators are concerned about the moisture and CO_2 content of biogas fuel. If water droplets form in the fuel stream, they may react with CO_2 to form carbonic acid which can cause corrosion problems. Carbonic acid formation is considered unacceptable by UOG operators.

The challenges outlined above are considered major barriers that would eliminate the possibility of operating UOG engines on biogas.

5.2.3 Option 2: Process Heaters

Process heaters such as line heaters and emulsion treaters are more tolerant to variations in fuel quality than internal combustion engines and are the preferred option for biogas utilization at UOG facilities. Typically, process heaters are oversized and employ an on/off temperature control system. Operating these heaters on biogas or a blend of natural gas and biogas will not significantly impact their performance. UOG operators consider biogas used to fuel process heaters as a feasible opportunity. Design options to address industry concerns include:

- Load matching and reliability: A blend of natural gas and biogas is preferred because it addresses the challenge of seasonal biogas supply variation and load matching. Natural gas purchased from the local gas co-operative will always be available.
- Connection point: Ideally, the biogas tie-in point would be close to the heating unit. In this manner, it may be possible to reduce biogas compression and pipeline requirements.
- Moisture: Provisions to remove moisture and other impurities in the biogas fuel before delivery to process heaters is required.

Regardless of the end user, several common technical details must be addressed before a biogas plant can supply biogas offsite. Typically, compression up to 690 kPa is required to transport and meet tie-in pressure with existing co-op distribution lines. Controls on the compressor must ensure it shuts down when upstream supply is low or when downstream demand is insufficient. Intermediate storage (i.e., a biogas accumulator) between the compressor and bioreactor cannot be avoided due to the possibility of vacuum conditions in the bioreactor tanks causing air infiltration. Vacuum conditions could also compromise the structural integrity of the tanks. Provisions for a 300 m^3 tank to provide three to four hours of biogas storage/accumulation are included in the economic analysis. Also, the H_2S concentration in the biogas must be reduced to 15 ppmv before it enters the compressor and to meet pipeline specifications (TransCanada, 2005).

To provide accurate reporting of biogas sales, metering equipment would be required. The Alberta EUB Directive 017 provides guidance on measurement requirements that are consistent with those used by the UOG industry. Registration as Business Associate (BA) with the Alberta EUB is necessary before the project proponents can apply for a pipeline license. Pipeline licensing requirements are outlined in Alberta EUB Directive 056.

Industry representatives suggest that this may be the easiest contractual agreement to arrange out of the three biogas utilization options considered. Reliability, disconnection penalties, and multi-party contracts present minimal concern when negotiating this fuel purchase agreement.

Further details on biogas compression, storage, metering, and approval requirements is presented in Appendix B.

5.3 Initial Economic Evaluation

The additional equipment costs for compression and delivery of biogas fuel to UOG facilities has a negative impact on the biogas plant feasibility relative to the previous options. The value of biogas when sold as a heating fuel is good, but its annual revenue is still only a small portion of the total economic benefit. This revenue justifies storage, compression and distribution equipment but it cannot provide the same economic return as the previous options. Key assumptions, energy prices and projected payout period are presented in this section.

5.3.1 Key Economic Comments from UOG Industry Representatives

The following input was contributed by UOG industry representatives:

- It is reasonable to assume UOG operators would purchase biogas for heating purposes since this the associated reliability issues of this fuel supply is unlikely to jeopardize hydrocarbon production provided supplemental co-op gas is also available.
- A price discount of 10 percent may be sufficient to motivate UOG operators to switch biogas where practicable.

5.3.2 Potential Revenue

Revenue is generated by selling biogas to UOG facilities for process heating. This gas would replace natural gas normally purchased from local gas co-operatives. Natural gas rates in Alberta during October and November 2005 ranged between $12-$13/GJ (Alberta Energy, 2005). To create an incentive for UOG companies, the biogas is discounted 10 percent from the Utility Gas Cost Recovery Rates. Therefore, economic modeling uses a biogas gas price of $10.8/GJ.

5.3.3 System Costs

Additional equipment is required to transport biogas to suitable UOG facilities. Cost provisions are included for the following biogas processing, handling and transport requirements:

- H_2S removal and monitoring.
- Approximately 400 m^3 of onsite biogas accumulation capacity.
- Monitoring and control of system pressure, temperature and flow rates plus the supply of a host building.
- A totalizing flow meter.
- Compression up to 690 kPa (100 psi).
- A 5 NPS polyethylene pipeline up to 1000 meters long.

The bulk of cost the increase is associated with the biogas accumulator, the compressor skid and the long transportation distance to the nearby UOG heater. This additional cost has an adverse impact on the projected payout period relative to that presented in Section 3.3. Table 5.1 shows that the revenue generated from biogas fuel sales will payoff the necessary equipment in 5 years. This payoff period is greater than the 2 years it takes to payoff electricity generating equipment.

One more year is required to recover the initial capital investment in good biogas opportunity areas (i.e. orange zones in Figure 3.1) which increases the total payout to about 8 to 10 years. Two more years are required in moderate biogas opportunity areas (i.e. yellow zones in Figure 3.1) which increases the total payout is about 14 to 16 years. An interest rate of 4.5 percent is assumed.

Table 5.1: Incremental Cost/Benefit of Fuel Delivery				
Biogas Plant Description	**Capital Cost Ratio**[1]	**Benefits**[2]	**Mixed Feedstock**[3]	
			Component Payout Period (years)[4,6]	Entire Plant Payout Period (year)[5,6]
Basic Bioreactor (tanks, feed handling, effluent handling and flare)	1	-manure and meat waste disposal -fertilizer production	10	10
Bioreactor with heat and power Excess electricity used onsite	1.075	-electricity and process heating -manure and meat waste disposal -fertilizer production	2	8
Bioreactor with fuel delivery capabilities Excess biogas delivered to nearby UOG facility for process heating	1.189	-biogas fuel sold to UOG process heaters -manure and meat waste disposal -concentrated fertilizer production	5	9
Bioreactor with fuel delivery and water treatment Excess biogas delivered to nearby UOG facility for process heating and water used on farm	1.303	-electricity sold to UOG and heat used onsite -clean water -manure and meat waste disposal -concentrated fertilizer production	7	9

1 Ratio of incremental capital cost to basic bioreactor cost. Initial investment for basic bioreactor is estimated at $2.67 million.
2 Incremental benefits achieved as additional equipment is included in biogas plant.
3 Economic analysis based on feedstock of 10 percent meat waste and 90 percent cattle manure.
4 Projected payout period of additional equipment is based solely on the revenue generated by the additional equipment. Interest rate is set at 4.5 percent.
5 Projected payout period for entire biogas plant based on combined revenue of the plant. Interest rate is set at 4.5 percent.
6 Payout periods based on commodity prices presented in Table 3.4.

5.4 Proximity to Appropriate UOG facilities

Figure 5.1 identifies areas in Alberta where opportunity exists for biogas to be supplied as fuel for process heaters. The best opportunities exist in eastern Alberta near Provost. Outside of these areas, the concentration of heaters operating on sour systems is only moderate at best. Finding an appropriate farming operation in close proximity to an appropriate UOG heater may still be a challenging task. The number of candidate heaters is much less than the number of candidate UOG facilities that could use bio-gas produced electricity or pipeline systems that could accept raw biogas. An investigation of licensed

UOG facilities in Alberta yielded a list of sites where heating fuel may be required. The search was conducted in areas where the biogas plant is likely to be located on a farm and UOG facilities are the end energy users. Candidate sites for biogas fuel use include sour oil batteries and sour gas gathering systems. It is anticipated that many of these sites currently purchase natural gas from local co-operatives for use in line heaters and emulsion treaters.

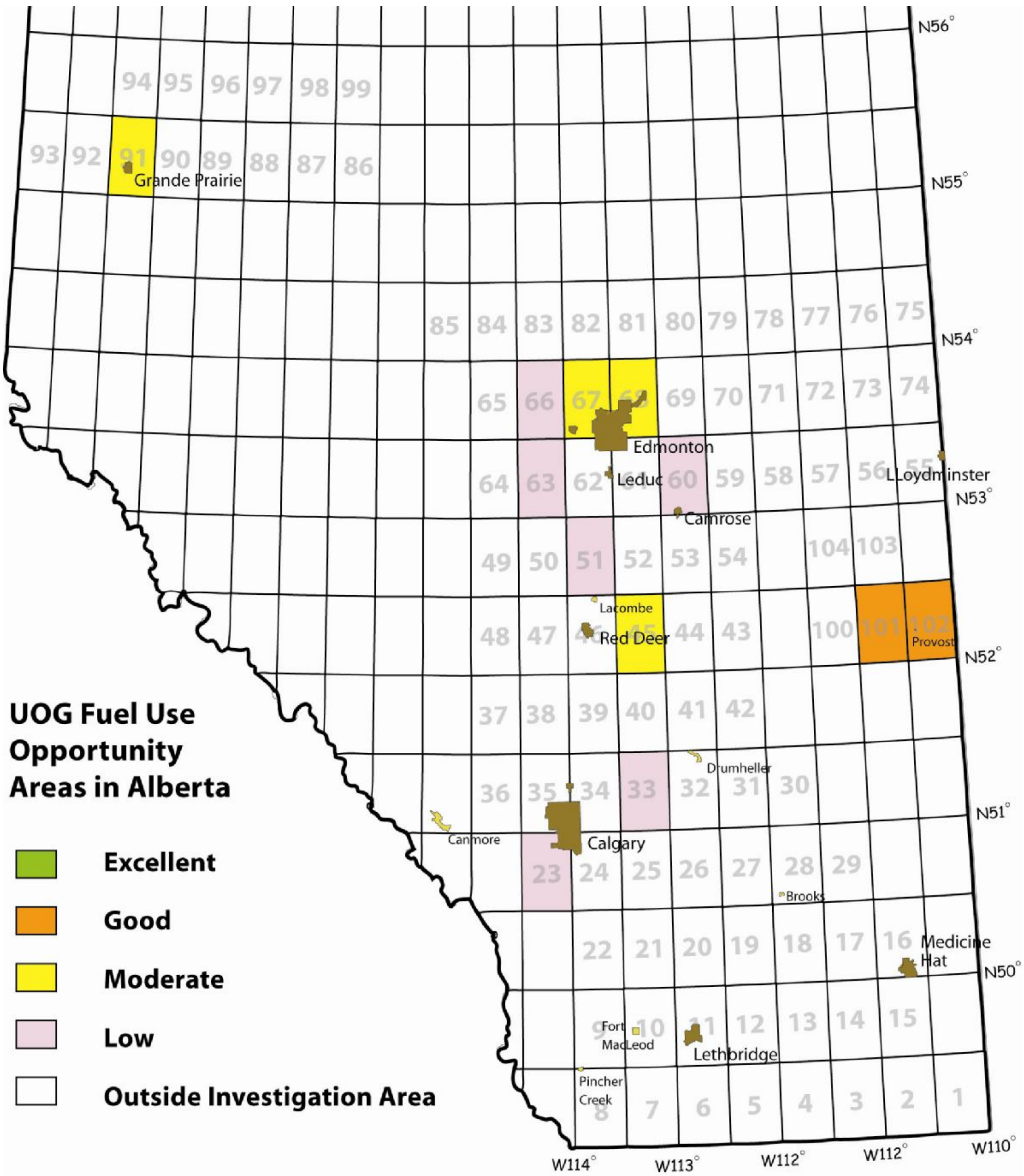

Figure 5.1: Biogas as Fuel - Opportunity Map

Data for this investigation was taken from Alberta EUB licensed facility reports and previous investigations conducted by Clearstone Engineering (AEUB, 2005c; CAPP 2005).

The geographic distribution of appropriate heaters within each relevant grid area is presented in Table 5.2. Each grid area is divided into four sub-zones: Northwest, Northeast, Southwest and Southeast. Caution should be used when referencing numbers in Table 5.2. These values represent theoretical heaters that may purchase fuel gas from the local Co-operative. The facilities listed may not actually have heaters and in most cases will likely be supplied with sweet gas from nearby gas processing plants.

Table 5.2: Distribution of Heaters within Selected Areas

Grid Area	NW Corner	NE Corner	SW Corner	SE Corner
23	1	0	9	3
33	5	0	0	0
45	5	14	3	5
51	5	0	1	0
60	0	0	0	0
63	3	1	5	0
66	1	2	0	0
67	3	4	6	22
68	5	20	0	0
91	9	3	7	5
101	21	16	35	28
102	70	28	21	20

6 PRODUCTION OF BIOGAS INTO NEARBY UOG GATHERING SYSTEMS

Delivery of raw biogas into low-pressure gas gathering systems or multi-phase flow lines is a practicable solution given the abundance of pipelines in Alberta and minimal technical challenges encountered. Almost infinite energy demand is accessed by connecting to existing UOG pipe networks. Plus equipment for gas upgrading is typically available downstream for a small processing fee. Redundant (or backup) energy systems are not required because downstream facilities don't rely on biogas for energy. The disadvantage of this energy utilization option lies in the capital cost required for compression and intermediate storage of biogas. Additional equipment costs have a negative impact on the biogas plant's feasibility relative to the case presented in Section 3.3. Technical and economic factors considered as well as a description of the proposed system are presented in the sections presented below.

6.1 Description

Gas gathering systems and multi-phase flow lines are very common in Alberta. It is anticipated that appropriate pipe networks will often exist in close proximity to proposed rural biogas plants. Raw biogas could be compressed and transported short distances to such pipelines. Supply of biogas into hydrocarbon lines would occur after the well head, but before any processing facilities to reduce compression duty. Gas gathering systems and flow lines may contain a wide range of liquid and gaseous components including H_2O, H_2S and CO_2. Introduction of biogas at relatively low flow rates will have little impact on hydrocarbon stream quality.

A 1700 m^3 bioreactor is used to evaluate this option because it is estimated to deliver the maximum economic benefit for minimum investment. Biogas production rates for this size of plant would vary between 2200 m^3/day and 3000 m^3/day. The amount of feedstock required for this range of biogas production is equivalent to the estimates presented in Section 5.1. Similarly, heating requirements consume part of the produced biogas and reduces the volume available for sale. The absence of waste heat recovery is a disadvantage for this option. The anticipated biogas volume available for sale should vary between 600 and 2400 m^3/day depending on the ambient conditions.

6.2 Technical Considerations

The delivery of raw biogas into nearby UOG pipelines is a technically straightforward task. No redundant energy systems are required and the necessary gas processing equipment would already be available downstream of the biogas plant. UOG industry comments listed below provide valuable guidance for the technical evaluation of this energy utilization option.

6.2.1 Key Technical Comments from UOG Representatives

Technical comments regarding the delivery of raw biogas directly into low-pressure gathering systems or flow lines include the following:

- Biogas composition should not impact UOG operations unless biogas causes downstream sales gas to exceed 2 percent CO_2 content or 15 ppmv H_2S content. Both concerns are not likely given downstream gas treating processes that would be encountered and/or the gas dilution that would occur through commingling of biogas with UOG production.
- Very low-pressure gas gathering systems exist and, in some cases, it may even be possible to rely on downstream suction to move the biogas. However, gathering systems are very dynamic and new wells coming online may increase line pressures over short time periods. This could back out or impede the biogas production.
- Biogas production volumes would be relatively small and, therefore, may not be of interest to UOG companies. Gas wells are often shut-in when production drops to less than 1000 m^3/day.
- It is expect that suitable pipelines in close proximity may not be hard to find in the target areas.
- High level institutional approval may be required before biogas can be introduced to pipelines. The Petroleum Registry would have to create a biogas code so that it could be tracked and provincial royalty fees avoided.
- Contract agreements may become complicated when multi-owner gather systems or facilities are encountered.

Before biogas can be delivered offsite several technical details must be addressed. Similar to the previous utilization option, biogas compression and storage equipment is necessary to achieve line pressures consistent with those encountered downstream. Downstream pressures may be very low and result in low biogas compression duty. However, given the dynamic nature of gathering systems, provision to compress the biogas to at least 1034 kPa may be warranted. A biogas storage buffer is required between the bioreactor and the compressor to avoid air infiltration. If vacuum conditions are created due to insufficient biogas production, the compressor may draw air into the bioreactor. Air infiltration could upset the anaerobic process, contribute to equipment corrosion and, if great enough, pose an explosion hazard. Vacuum conditions may also compromise the structural integrity of the bioreactor tanks. A 400 m^3 tank can provide three to four hours of biogas storage and should limit shutdown-start up compressor cycling due to supply variations. The H_2S concentration in the biogas must be reduced to 15 ppmv before it can enter the compressor.

Accurate metering would be required to establish biogas production rates. The biogas plant would not have to pay any royalties on the produced biogas because there are no mineral rights involved. Alberta EUB Directive 017 provides measurement guidelines to ensure consistent metering practices with UOG companies. Alberta EUB Directive 056 requires a pipeline license before the raw biogas can be delivered.

Some contract complications may occur if pipelines have multi-ownership. But biogas purchase agreements would still be much simpler than power purchase contracts.

More details on raw biogas delivery into low-pressure pipe networks are provided in Appendix B.

6.3 Initial Economic Evaluation

The major disadvantage of producing biogas into low-pressure gas gathering systems or flow lines is that it has a net negative impact on biogas plant feasibility. Projected payout periods increase by one to two years because of the equipment costs required for compression, storage and delivery of biogas. Energy prices and key assumptions are presented further on in this section after the comments from UOG representatives (i.e., in Section 6.3.2).

6.3.1 Key Economic Comments from UOG Representatives

Important economic considerations regarding the delivery of raw biogas directly into low-pressure gathering systems or flow lines include the following:

- Proponents of the biogas plant could consider themselves as a regular gas producer and sell to downstream markets. The net value of the gas would simply be the market value minus processing and transportation fees.
- There is little economic incentive for UOG facilities to process biogas. More incentive would exist if the gathering system was underutilized and the volumes of biogas were significant relative to the available unused capacity.

6.3.2 Potential Revenue

When processing, transporting and marketing fees are included, the net value of biogas is estimated to be about $10/GJ. No price discount incentive is included in this estimate. A survey of industry representatives suggests that processing fees would range from $25 to $35 per 1000 m^3 which accounts for the additional duty required to remove CO_2 and H_2S and then compress the treated biogas. The gross market value of natural gas ranged between $11 and $13 per GJ during the fall of 2005 (Gas Alberta Energy, 2005).

It may be possible to generate additional revenue from the sale of green energy certificates. Market demand exists for low-impact renewable energy sources and biogas is a good candidate to meet this demand. Quantifying the value of a green energy certificate for biogas is difficult because no biogas certificates have been sold.

6.3.3 System Costs

Additional equipment is required to transport biogas to suitable UOG gas gathering systems. The cost provisions are accounted for in the following biogas handling and transport requirements:

- A 400 m^3 onsite biogas accumulation system.
- Systems for monitoring and controlling pressure, temperature and flow rates plus a host building for the equipment.
- Metering.
- Compression up to 1034 kPa (150 psi)
- A 5 NPS polyethylene pipeline up to 300 meters long.

The bulk of the additional cost is associated with the biogas accumulator and the compressor skid package.

6.3.4 Projected Payout Period

The additional cost ratio for the biogas accumulator, pipeline and compression is presented in Table 6.1 and has an adverse effect on the projected payout period relative to the options presented in Section 3 and 4. The revenue generated from raw biogas delivery into gas transmission lines takes 6 years to payoff the additional equipment. This is much longer than the 2 years required to pay off electricity generating equipment. The payout period for the entire biogas plant increases by one year for plants operating in the orange opportunity areas of Figure 3.1.

Table 6.1: Incremental Cost/Benefit of Raw Biogas Delivery to Gathering Systems

Biogas Plant Description	Capital Cost Ratio[1]	Benefits[2]	Mixed Feedstock[3]	
			Component Payout Period (years)[4,6]	Entire Plant Payout Period (year)[5,6]
Basic Bioreactor (tanks, feed handling, effluent handling and flare)	1	-manure and meat waste disposal -fertilizer production	10	10
Bioreactor with heat and power Excess electricity used onsite	1.075	-electricity and process heating -manure and meat waste disposal -fertilizer production	2	8
Bioreactor with biogas delivery to gathering systems Excess biogas delivered to nearby UOG gathering systems	1.179	-raw biogas sales to gathering systems -manure and meat waste disposal -concentrated fertilizer production	6	9
Bioreactor with biogas delivery to gathering systems and water treatment Excess biogas delivered to nearby UOG gathering systems and water used on farm	1.293	-electricity sold to UOG and heat used onsite -clean water -manure and meat waste disposal -concentrated fertilizer production	6	9

7 Ratio of incremental capital cost to basic bioreactor cost. Initial investment for basic bioreactor is estimated at $2.67 million.
8 Incremental benefits achieved as additional equipment is included in biogas plant.
9 Economic analysis based on feedstock of 10 percent meat waste and 90 percent cattle manure.
10 Projected payout period of additional equipment is based solely on the revenue generated by the additional equipment. Interest rate is set at 4.5 percent.
11 Projected payout period for entire biogas plant based on combined revenue of the plant. Interest rate is set at 4.5 percent.
12 Payout periods based on commodity prices presented in Table 3.4.

6.4 Proximity to Appropriate UOG facilities

Figure 6.1 illustrates areas in Alberta where opportunity exists for biogas to be supplied into existing gas gathering systems or flow lines. Good opportunities for this option exist in every zone investigated. Identifying a suitable location for the biogas plant can focus on minimizing manure transportation costs and not on finding suitable energy end users. The selection of candidate sites for delivery of biogas into UOG pipe networks is based on an investigation of low-pressure flow lines, oil batteries with gas conservation schemes and gas gathering systems. These lines could be either sweet or sour and are assumed to operate at pressures less than 1000 kPa (although some systems may operate at higher pressures). The search was conducted in areas where biogas plants would be most likely located on a farm.

Data for this investigation was taken from the Alberta EUB licensed facility reports and pipeline attribute file (AEUB, 2005c; AEUB, 2005d).

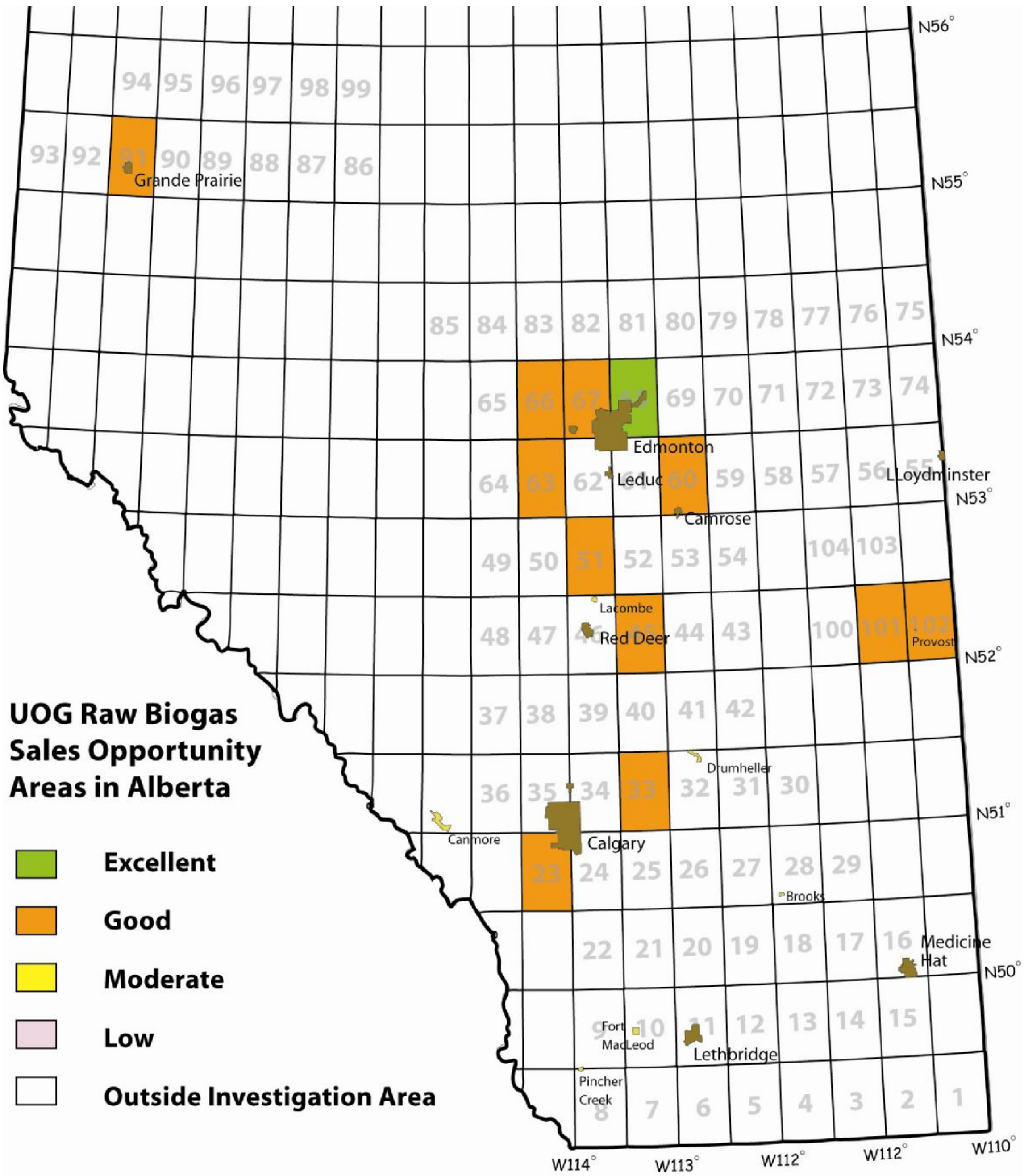

Figure 6.1: Raw Biogas Sold into Pipelines - Opportunity Map

The geographic distribution of gathering systems, oil batteries with gas conservation schemes and low-pressure flow lines within each relevant grid area is presented in Table 6.2. Each grid area is divided into four sub-zones: Northwest, Northeast, Southwest and Southeast. A good distribution of appropriate systems is available in most zones.

Table 6.2: Distribution of Gathering Systems in Selected Areas

Grid Area	NW Corner	NE Corner	SW Corner	SE Corner
23	11	46	22	14
33	30	36	29	16
45	18	55	27	23
51	42	19	58	80
60	42	43	43	0
63	38	49	94	66
66	43	15	67	89
67	6	22	82	120
68	58	72	138	146
91	26	15	67	20
101	27	23	41	58
102	101	58	53	62

7 CONCLUSIONS AND RECOMMENDATIONS

7.1 Conclusions

Biogas plants can reduce odour, pathogen loading, impact on water quality and GHG emissions from confined feeding operations in addition to being a source of low-impact, renewable energy. They also present an opportunity for rural communities to diversify their economies and improve relations with UOG companies. The primary challenge for biogas development is locating appropriate feedstock sources that will result in economically viable operations. Small-scale bioreactors can be economically attractive when the right mix of meat processing waste and manure is available. Green zones in Figure 3.1 identify areas in Alberta where favourable conditions exist for sustainable biogas production.

The most sustainable biogas plants will utilize all excess bio-energy onsite where maximum economic benefit can be achieved. Only when insufficient energy demand exists should project proponents consider integration with the UOG industry.

Options for integrating biogas plants with appropriate energy collection and utilization systems in the UOG industry have been evaluated and the opportunities and challenges of each are identified. The technical evaluation concludes that biogas energy can be supplied to UOG facilities via three mechanisms:

- Option 1: Electricity generated at the biogas plant can be transmitted on independent power lines to a dedicated group of electrical driven pump jacks.
- Option 2: Processed biogas can be delivered to UOG facilities as a fuel for process heating.
- Option 3: Raw biogas can be delivered to low-pressure gas gathering systems and flow lines and upgraded at downstream facilities to sales quality natural gas for customers.

Of these mechanisms, option 1 has the most technical challenges. Issues related to power purchasing agreements and reliability present significant barriers. These barriers do not exclude option 1 from occurring but the project implementation will likely be more onerous. Options 2 and 3 have received encouraging feedback from UOG industry representatives and do not present any significant technical barriers.

The economic analysis indicates that the addition of equipment for UOG utilization of excess biogas does not present a significant economic barrier. Projected payout period remains the same for Option 1, while Options 2 and 3 have only small increases in the payout period. Unfortunately, no opportunities were identified that resulted in an improved payout period. Biogas plant feasibility is still primarily dependant on co-benefits. That is, the value of avoided cost from meat waste disposal, manure spreading and fertilizer purchase is much more important than the value of the energy generated.

The introduction of UOG end users does not improve project economics; it only increases the opportunities for bio-energy utilization.

Response from UOG representatives indicates that joint venture biogas projects are possible given the following conditions:

1. An economic incentive exists for UOG facilities.
2. Current hydrocarbon production is not adversely affected.
3. GHG reduction and sustainable development objectives are achieved.

Direct GHG offset credits can be an important biogas plant revenue stream when credit prices reach the neighbourhood of \$15/tonne CO_2E. However, the small volume of credits generated by biogas plants may not interest carbon buyers unless they can be pooled with other projects to achieve the 100 kilotonne threshold.

7.2 Recommendations

The key recommendations from this report are as follows:

- Governments should encourage biogas plant development in the green zones of Figure 3.1 where excess bio-energy can be utilized onsite. Small-scale bioreactors established in these areas could demonstrate the economic opportunity as well as environmental and social benefits from anaerobic digester technology. A successful showcase is essential before this waste management alternative can gain mainstream acceptance.

- A consortium of agri-processors, intensive livestock operators and farmers should undertake a detailed business case study to facilitate the creation of a pilot biogas plant. The pilot plant should be located in a green zone and all excess bio-energy used onsite.

- Governments should facilitate the profitable sale of GHG offset credits from small-scale operations. This can be accomplished via two mechanisms:

    1. The direct purchase of GHG offset credits by governments from small-scale, renewable energy system operators at market prices.
    2. The establishment of bio-energy protocols to ease the administrative burden, ensure confidence and facilitate pooling of GHG offset projects. The protocols should be useful to individual farm operators and detail monitoring methodology, frequency and equipment required.

- When biogas production exceeds onsite energy demand, biogas plant proponents should engage UOG companies with sustainable development objectives. Such companies are more likely to support biogas proponent efforts to overcome the technical and economic challenges identified in Sections 4, 5 and 6.

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APPENDIX A: TECHNICAL AND ECONOMIC DETAILS OF ELECTRICITY GENERATION AND DISTRIBUTION

A.1 Reliability

An independent generator supplying power to a group of dedicated users will never achieve the same level of reliability as the AIES. Because the AIES draws from a large number of generators, individual plant maintenance, emergency shutdowns or introduction of new technologies have little impact on electricity supply reliability. When the end user relies on a single generator, reliability does become an issue. Biogas production and power generation is subject to a continuous supply of adequate quality feedstock. If the supply of manure or meat waste is reduced or unavailable, the production of biogas will decrease. To address reliability issues, a provision for fuel blending is needed. The power generator purchased would need to have two carburetors: one to accommodate low BTU biogas and the other for natural gas. In this manner, the biogas plant could deliver a reasonable level of reliability even if biogas production is off line.

Both the biogas plant and UOG equipment require regular maintenance. Synchronizing maintenance schedules would reduce downtime for both stakeholders. Biogas would be flared during generator maintenance.

A.2 Load Matching

The number and size of appropriate pumpjacks in close proximity to the biogas plant will determine the power demand. Equipment power demand will likely be larger than that available from biogas alone. A generator with two fuel inputs will address load matching issues. Increasing the supply of natural gas to an adequately sized generator will achieve higher power supply rates. Conversely, if a pumpjack shuts down and the overall demand decreases, the natural gas supply can decrease to match the new demand.

A.3 Intermediate Storage and Pressure

Intermediate storage and compression of biogas is not required for generating electricity on site.

A.4 Gas Composition

Hydrogen sulphide (H_2S) concentrations in the biogas must be reduced from approximately 500 ppm to 20 ppm to meet generator fuel quality specifications. The iron sponge technology with continuous H_2S monitoring is an appropriate H_2S removal technology.

A.5 Metering

Electricity metering must comply with Measurement Canada requirements (Sections 9(1), 9(2) or 9(3) under the Electricity and Gas Inspection Act) and the Transmission Administrator of Alberta Ltd. The metering equipment must be suitable for environmental and operating conditions encountered at the installation site. It must also continuously log cumulative energy readings and be able to retain those readings for at least 14 days in the absence of line power. The meter must have an accuracy class rating that meets or exceeds the values specified in Appendix I of the Distributed Generation: Interconnection Guide. The metering equipment must also meet the following safety requirements:

- CSA standard C22.2,
- ANSI/IEEE C57.13-1983, and
- Measurement Canada Standard Drawings.

Currently, generators have two options regarding Meter Data Management (MDM): (1) generators can own their own meters and conduct metering services themselves, or (2) generators can contract a third party to provide this service. MDM costs may be about $150/month (Alberta Energy, 2005).

A.6 Electric Overload Protection Requirements

The generator owner must install the necessary circuit breakers that will trip when the voltage is outside of predetermined ranges. Frequency selective relays are also necessary to separate the generator in cases of extreme frequency variation. A visible disconnect switch must be installed and maintained by the generator.

Power surge during pumpjack motor start-up should be accounted for. Electricity transmission lines should be rated for 3 to 4 times the nominal motor amperage and overload protection included in the generator package. Generator surge power rating should be adequate to meet the starting requirements of UOG motors.

A.7 Power Quality

The generator must produce and transmit single-phase, 60 Hz, alternating current electricity at 480 or 600 volts. Power quality objectives are highlighted in the Alberta Distributed Generation: Interconnection Guide (Alberta Distributed Generation Technical and Policy Committee, 2002) and include:

- Generators serving isolated systems must be capable of controlling frequency to between 59.7 Hz and 60.2 Hz.
- Voltage levels must be at least equal to the voltage levels required by the end user. Voltage regulation guidance can be found in CSA Standard CAN3 C235.83.

- System grounding must conform to the Alberta Electrical and Communication Utility System Regulation 44/1976.
- Generator must be able to correct the power factor to ± 0.90.
- Conversion to three-phase at the end users must not exceed a phase-to-phase voltage unbalance of 1%.

The IEEE Standard 1159-1992: Recommended Practice for Monitoring Electric Power Quality is a useful guide for evaluating whether power quality objectives are achieved.

Further requirements are outlined in the Alberta Distributed Generation: Interconnection Guide (Alberta Distributed Generation Technical and Policy Committee, 2002).

A.8 Approvals

In addition to the approvals identified in Section 3.4, approvals are required under AEUB Directive 028: Applications for Power Plants, Substations, Transmission Lines, and Industrial System Designations subject to the Hydro and Electric Energy Act (AEUB, 2004). Application for exemption is possible if one of the following occurs:

- The transmission lines remain within the proponents property boundaries (Section 13 of the Hydro and Electric Energy Act).
- The transmission line crosses a public road but is less than 750 volts (Section 24 of the Hydro and Electric Energy Act).

The project proponents would have to apply for a Business Associate (BA) Code with the AEUB before any applications can be made.

The generating facility would also require county approval subject to local bylaws.

Air emissions from the generator must be below threshold concentrations listed in the Alberta Air Quality Objectives (Alberta Environment, 2005). Additionally, if the electricity produced is sold as low impact, renewable electricity; certification from the Environmental Choice Program is required (Environmental Choice Program, 2003).

The generation and transmission facilities must meet all applicable national, provincial and local construction and safety codes

The facility would require a Noise Impact Assessment outlined in the EUB Interim Directive 99-8 (AEUB, 2004).

A sales agreement between supplier and consumer must be established outlining compensation and responsibilities for each party. Micro-generators are responsible for any damage their equipment causes to other customers. Liability insurance may be desirable to mitigate any expenses incurred due to system failures. Insurance would also help simplify interconnection agreements (Alberta Distributed Generation Technical and Policy Committee, 2002). Industry representatives suggest that establishing a power contract with an ‘unproven’ technology may be a significant barrier. Additionally, penalties may apply to UOG companies for breaking existing power contracts with local utilities.

A.9 Electricity Price Estimate and Other Revenue

Cost estimates were based on the following ATCO Electric and Direct Energy fees applicable at the date of this report:

- ATCO Electric distribution charges are the sum of the Customer Charge (\$21.36/month); demand Charge (\$11.27/kW); the Energy Charge (0.38 ¢/kWh); and charge for deficient power factor for each individual point of service (ATCO Electric, 2005). Demand charge is based on the higher of:
  - Highest metered demand during the billing period
  - 85% of the highest metered demand during the 12 month period
  - Estimated demand
  - Distribution contract demand
  - 4 kW
  - Deficient power factor is considered to be less than 90 percent.

- Direct Energy electricity charges:
  - Flat rate of 6.45 ¢/kWh for oil and gas facilities

Figure 4.1 illustrates the relationship between UOG facility load size and the total electricity bill paid by the operators when equipment is operating 95 percent of the time.

Expected revenues per kilowatt-hour should recognize that both distribution services and electricity sales will be provided to the UOG facility. Distribution service revenue will be required to pay for the additional cost of metering and power lines. At the same time, a motivating incentive is necessary for the UOG sector to switch power suppliers. A balance between these factors may be a reduced electricity price (e.g., 10 percent below market value). Revenue modeling uses a value of \$0.08/kWh for both energy and distribution charges.

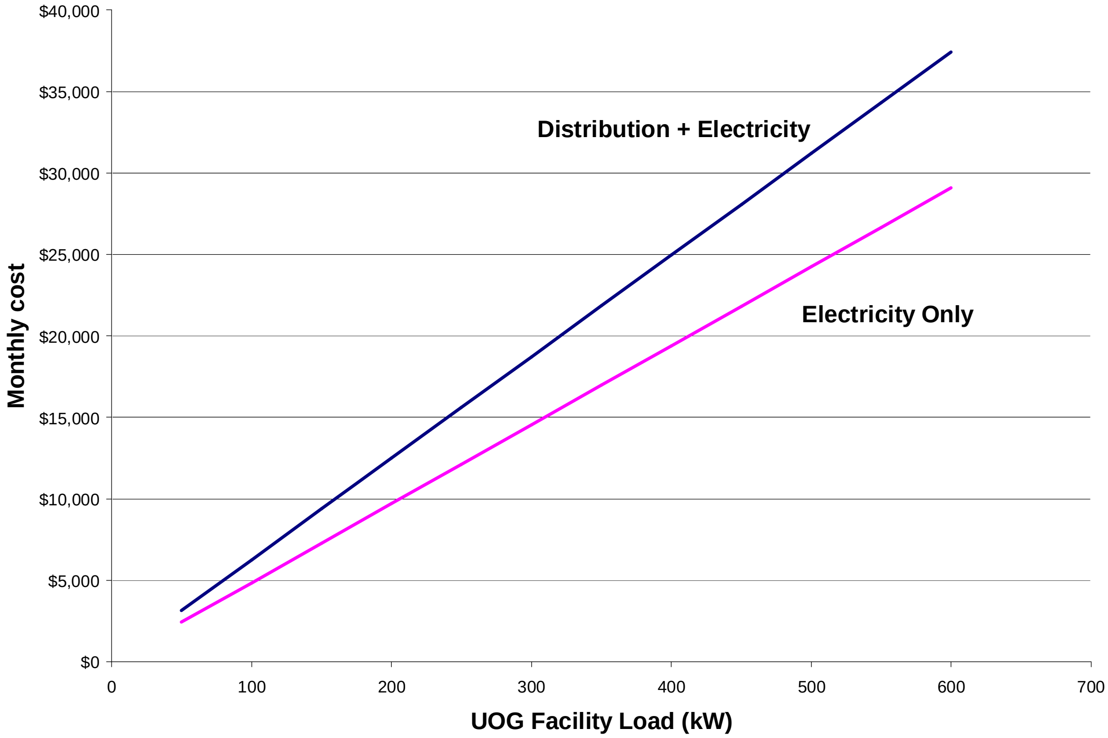

Figure A.1: Estimated Monthly Electricity Cost for UOG Facility

In additional to revenue from direct GHG offsets described in Section 3.3, indirect GHG offset credits can be obtained by supplying low-impact renewable electricity. Indirect offsets are generated when fossil fuel electricity is replaced with electricity from renewable sources. The national GHG intensity factor of 0.219 t CO_2 equiv/MWh is to be used when calculating indirect offsets (Government of Canada, 2005). Credits produced from a 200 kW generator operating 90 percent of the time are approximately 340 t CO_2 equiv/year. This represents an additional revenue stream of $3825 per year if GHG offset credits are valued at $11.25/t CO_2E. However, this revenue stream represents less than 0.5 percent of the total annual benefit described in Section 3.3 and may not be worth pursuing. More indirect offset credits could be obtained if the Canadian Government allowed direct comparison with provincial GHG intensity factors.

Alternatively, green power certification could be obtained and green certificates sold through a third party marketer. Currently, several green certificate retailers operate in Alberta; these include Enmax, Direct Energy and the Pembina Institute for Appropriate Development. Green certification attempts to enhance the economic value of environmentally and socially beneficial renewable energy projects. The Pembina Institute currently sells green wind certificates for $27/MWh (Pembina, 2005). Presently, green certificate sales would be much more valuable than sales of indirect GHG offset credits.

APPENDIX B: TECHNICAL DETAILS OF BIOGAS USED AS PROCESS FUEL OR DELIVERED INTO GATHERING SYSTEMS

B.1 Metering

The appropriate guide for design and installation of gas meters is Alberta EUB Directive 017: Measurement requirements for Upstream Oil and Gas Operations (AEUB, 2005a). Section 4.3 of the directive outlines relevant requirements for gas measurement. Important points include the following:

- Meter Type: Given the low flow, low pressure nature of biogas production, an inline turbine is the most suitable and affordable meter type. The directive states that a turbine meter must be designed and installed according to the provisions of the latest edition of AGA #7: Measurement of Gas by Turbine Meters. For sales or delivery measurements, the installation must include instrumentation that allows for continuous pressure, temperature and compressibility corrections either on site (e.g. electronic monitoring) or at a later date (e.g. pressure and temperature charts).
- Physical properties of natural gas components are defined in the most recent edition of the Gas Processors Suppliers Association (GPA) SI Engineering Data Book.

Production Data Verification and Audit Trail: Best practices outlines in EUB Directive 017 suggest that field data, record and calculations submitted to the Petroleum Registry should be kept for inspection on request. Records should be maintained that identify the gas stream being metered, the measurement device, and all measurements related to the determination of gas volumes.

Gas composition should be verified and documented during an initial monitoring period and checked on a monthly basis thereafter. Gas sample analysis may be conducted by the closest appropriate laboratory.

B.2 Approvals

In addition to the approvals listed in Section 3.4, a biogas facility transporting and selling fuel gas offsite requires licensing subject to:

- AEUB Directive 056 – Schedule 3 (AEUB, 2005b). A license is required for the pipeline transporting gas.
- The bioreactor itself does not require an Energy Development License (Schedule 1) or a Facility License (Schedule 2).

The project proponents would have to apply for a Business Associate (BA) Code with the AEUB before any applications can be made. The biogas facility must meet all applicable national, provincial and local construction and safety codes.