EB-2011-0242
EB-2011-0283

INTHE MATTER OF the *Ontario Energy Board Act, 1998, S.O. 1998*, c.15, Schedule B; and in particular section 36(2) thereof;

AND IN THE MATTER OF an application by Enbridge Gas Distribution Inc. for an Order or Orders approving and setting Ontario renewable natural gas prices for Enbridge Gas Distribution Inc.'s purchase of renewable natural gas;

AND IN THE MATTER OF an application by Union Gas Limited for an Order or Orders approving and setting Ontario renewable natural gas prices for Union Gas Limited's purchase of renewable natural gas.

MATERIALS RELIED ON BY
ENBRIDGE GAS DISTRIBUTION INC.
FOR SUBMISSIONS ON JANUARY 12, 2012

AIRD & BERLIS LLP
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Counsel for Enbridge Gas Distribution Inc.

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TABLE OF CONTENTS

DRAFT ISSUES LIST

EB-2011-0242
EB-2011-0283

1.0: Role of the Utilities

1.1 Do the applications fit with the objectives for natural gas under the OEB Act?

1.2 Is the proposed role of both Enbridge and Union in developing and implementing a RNG program reasonable and appropriate?

2.0: Pricing Framework

2.1 Are the proposed purchase prices from landfill sources reasonable and appropriate?

2.2 Is the proposed annual breakpoint per site for landfill sources reasonable and appropriate?

2.3 Are the proposed purchase prices from anaerobic digester sources reasonable and appropriate?

2.4 Is the proposed annual breakpoint per site for anaerobic digester sources reasonable and appropriate?

2.5 Is the proposed maximum term length for RNG contracts (20 years) reasonable and appropriate?

3.0: Volume Caps

3.1 Is the proposed maximum volume cap of 3.3 petajoules (87 million m^3) of RNG for Enbridge reasonable and appropriate?

3.2 Is the proposed maximum volume cap of 2.2 petajoules (58 million m^3) for Union reasonable and appropriate?

4.0: Supporting Structure

4.1 Is the proposed 5-year contract acceptance window following Board approval for RNG supply reasonable and appropriate?

4.2 Is the proposed contract structure reasonable and appropriate?

4.3 Are the proposed connection procedures reasonable and appropriate?

4.4 Are the proposed capital contributions for potential RNG producers reasonable and appropriate?

4.5 Is the proposed capacity allocation process to access the utilities' distribution and transmission systems reasonable and appropriate?

4.6 Are the proposed gas quality standards to be met reasonable and appropriate?

4.7 Is the proposed system for treating any and all environmental attributes reasonable and appropriate?

Ontario Energy Board Act, 1998

S.O. 1998, CHAPTER 15
SCHEDULE B

Consolidation Period: From June 6, 2011 to the e-Laws currency date.

Last amendment: 2011, c. 9, Sched. 27, s. 34.

PART I
GENERAL

Board objectives, electricity

1. (1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.
2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.
4. To facilitate the implementation of a smart grid in Ontario.
5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities. 2004, c. 23, Sched. B, s. 1; 2009, c. 12, Sched. D, s. 1.

Facilitation of integrated power system plans

(2) In exercising its powers and performing its duties under this or any other Act in relation to electricity, the Board shall facilitate the implementation of all integrated power system plans approved under the *Electricity Act, 1998*. 2004, c. 23, Sched. B, s. 1.

Board objectives, gas

2. The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives:

1. To facilitate competition in the sale of gas to users.
2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.
3. To facilitate rational expansion of transmission and distribution systems.
4. To facilitate rational development and safe operation of gas storage.
5. To promote energy conservation and energy efficiency in accordance with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

5.1 To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

6. To promote communication within the gas industry and the education of consumers. 1998, c. 15, Sched. B, s. 2; 2002, c. 23, s. 4 (2); 2003, c. 3, s. 3; 2004, c. 23, Sched. B, s. 2; 2009, c. 12,

OVERVIEW

The evidence is set out below in the following Parts:

I. Background on RNG

II. Benefits of RNG

III. The Need for Ontario RNG Supply Prices

IV. The Role of Utilities in Enabling a Viable RNG Industry

V. Market Considerations

VI. Regulatory Developments in Other Jurisdictions

VII. The Principles of the Proposed RNG Program

VIII. Details of the Proposed RNG Program

IX. Operational Impacts of RNG Supply

EVIDENCE

Part I: Background on RNG

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

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

A detailed explanation of all of the sources and the market potential of RNG is provided in the report "Potential Production of Renewable Natural Gas from Ontario Wastes" prepared by Alberta Innovates for the Utilities and attached as Exhibit B, Tab 1, Appendix 1.

Production of Biogas in Digesters

For the purposes of waste management, digesters can be constructed in a number of different places including:

- On farms, using manure, crop residue and other wastes such as fats, oil and grease obtained off-farm.
- At waste water treatment plants, using the biosolids from the treatment process.
- At municipal sites, using materials from source-separated organics collection programs (*e.g.* "Green Bin").
- At sites such as breweries, food and beverage plants and food processing companies, using the respective waste products.

In each of these cases, anaerobic digestion can significantly reduce the amount of organic matter which might otherwise be spread on land, sent to landfills, incinerated or disposed of in some less useful manner. The products of a digester are biogas, which is energy, and the digestate, which can be employed as fertilizer.

Many waste streams which undergo natural anaerobic digestion release methane and CO_2 into the atmosphere as they decompose. Relative to CO_2, methane has the effect of creating 21 times more greenhouse gases ("GHGs"). The proposed RNG Program enables capture and redirection of methane that would otherwise be released into the atmosphere and turns the methane into a useful energy source. This conversion of potentially wasted energy is critical when evaluating the environmental impact of generating RNG.

Using and Refining Biogas and Landfill Gas

Raw biogas typically consists of 55 to 60% methane with the remaining 40 to 45% being CO_2 and small amounts of impurities such as hydrogen sulphide (H_2S). Raw biogas is typically used in two ways:

1. After some of the impurities are removed, the biogas can be burned in an engine or turbine to generate electricity. Biogas used for this purpose is typically only cleaned of contaminants that impact the reliability of generators; therefore the resulting gas offers a lower heat value than natural gas or RNG. The electrical conversion efficiency of these on-site generators is normally less than 40%.[1]

2. RNG is created from the raw biogas by removing the CO_2 and other impurities. Existing technology is available for this cleanup process which produces RNG that is interchangeable with natural gas. The RNG can then be injected into the local natural gas utility's distribution or transmission system. The RNG is transported to utility customers' homes and businesses where it is burned in existing heating, water heating, and process equipment. As indicated in the Alberta Innovates report attached as Exhibit B, Tab 1, Appendix 1, the RNG process can produce full-cycle efficiencies of up to 80% depending on the end-use natural gas equipment.

[1] Terasen Gas Inc., Biomethane Application, June 8, 2010

Landfill gas is similarly used to produce electricity or RNG, the only difference is that there are other impurities in landfill gas that must be removed. Cleanup processes and technologies exist and are commercially available to do this.

As set out above, the production of RNG and injection into the natural gas system is a more efficient use of energy than electricity generation, and more desirable than flaring or venting to the atmosphere.

Part II: Benefits of RNG

As set out in greater detail below, using existing landfills and new and existing digesters to create RNG can provide environmental, economic and waste-related benefits. The opportunity to make use of these benefits has been recognized in the increasing number of provinces and communities that have adopted programs to separate organic waste from the landfill stream (*i.e.* through "Green Bin" type programs), and that are considering processing facilities which include anaerobic digestion. Exploiting the benefits offered by RNG is consistent with and complementary to the stated objectives of Ontario public policy.[2]

Benefits Specific to Landfills

Under conventional waste management practices, much of the organic waste generated by society was sent to landfills. These sites continue to generate gas long after the landfill has closed, and it is now recognized that these landfills are significant emitters of GHGs.

[2] Ontario Green Energy and Green Economy Act, 2009

Association of
Municipalities of Ontario

Office of the President

Sent via email:
BoardSec@ontarioenergyboard.ca

December 5, 2011

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto ON M4P 1E4

Dear Ms. Walli,

Re: EB-2011-0242 and EB-2011-0283

I am writing to offer additional comments from the Association of Municipalities of Ontario (AMO) on EB-2011-0242 and EB-2011-0283, submissions from Enbridge Gas Distribution and Union Gas respectively with regards to renewable natural gas.

We would like to re-iterate that AMO supports the drive to make our energy system cleaner, more responsive and more efficient. Specifically, we would like to provide information on how this proposal will assist municipalities in improving resource utilization in landfills and wastewater treatment plants, reduce greenhouse gas emissions, and improve local economic development.

Municipalities across the province are collectors of renewable natural gas in the form of methane which is generated by landfills and waste water treatment plants. However, this resource remains underutilized as most collection is either flared off or inefficiently converted to electricity. AMO supports the submissions since they leverage existing pipeline infrastructure to provide additional incentives to increase collection and improve utilization of methane gas within municipal operations. Renewable natural gas satisfies a triple bottom line approach to better utilizing this methane because it will:

- Lead to greater physical, cultural and financial access and equity in service delivery
- Use fewer natural resources
- Promote and maintain economic development and growth in a sustainable manner.

.../2

200 University Ave., Suite 801 Toronto ON M5H 3C6 Canada | E-mail: amo@amo.on.ca
| www.amo.on.ca Tel: (416) 971-9856 | Fax: (416) 971-6191 | Toll-free in Ontario: 1-877-426-6527

In addition, the proposal will serve Ontario's municipalities by reducing greenhouse gas emissions. Municipalities across the province are involved in activities to measure, monitor and reduce greenhouse gasses within their operations despite the lack of a regulatory framework for emission reductions. As methane is known to be 21 times more destructive than carbon dioxide in terms of its climate impacts, the sector welcomes efforts to mitigate its release. Such an initiative also places municipalities in a better position should mechanisms for cap and trade or other greenhouse gas reduction efforts come into force.

Finally, municipalities across the province have embraced the economic development opportunities offered by renewable energy. Many municipalities are actively seeking to attract new businesses and manufacturing facilities to locate within their boundaries. Municipalities also develop, and sometimes partner, in renewable energy projects. The proposal outlined in the submissions will enhance these opportunities by developing a market for renewable natural gas.

AMO is not for or against any one particular type of generation as we believe a broad portfolio of supply options mitigates the risk of dependence on any one fuel supply, and can help reduce risks for the rate base. Encouraging the development of renewable natural gas is good public policy for municipalities because it will improve use of existing methane resources within our landfills and wastewater treatment facilities, reduce greenhouse gas emissions in our operations, and grow our local economies. It is an important and necessary step to a future Ontario that is recognized as a leader in waste management, resource use, and energy creation – all of which will ensure the Province maintains a strong economy and a healthy environment.

Yours truly,

Gary McNamara
President, AMO

Regulation Proposal Notice:

Title:
Landfill Gas Collection and Control Regulation

EBR Registry Number: 010-0968
Ministry:
Ministry of the Environment
Date Proposal loaded to the Registry:
August 09, 2007

Keyword(s): Air | Waste
Related Act(s): Environmental Protection Act, R.S.O. 1990

The comment period for this proposal is now over.

Description of Regulation:

The Ontario Ministry of the Environment is proposing to amend regulations under the *Environmental Protection Act* (EPA) to require mandatory landfill gas collection and utilization or flaring for all operating or proposed new or expanding landfills with total waste disposal capacities larger than 1.5 million cubic metres.

Reductions in landfill gas (methane) emissions to the atmosphere will help contribute to Ontario's climate change goals and to any national or international greenhouse gas reduction targets.

Landfill Gas

The decomposition of the organic component of municipal waste in landfills produces landfill gas containing about 50% methane (CH4) and 50% carbon dioxide (CO2). Methane is a potent greenhouse gas as it has a global warming potential 21 times that of carbon dioxide. As a result landfills are considered a significant source of greenhouse gas emissions.

Landfill gas also contains trace amounts of other compounds, such as hydrogen sulphide, mercaptans and non-methane organics. These other compounds may cause odours or affect local air quality.

Landfill gas emissions can be controlled by installing a network of collection wells and directing the gas by fans to facilities for use of the gas, for example for the production of electricity or for use as fuel by a nearby industry, or for flaring (i.e. burning). Simply burning the methane to convert it to carbon dioxide reduces its global warming potential by about 95%. Use of the methane for energy purposes can further reduce greenhouse gas emissions by replacing other energy sources, such as natural gas or coal.

A number of larger closed or operating landfills currently have landfill gas controls in place, and already collect and use or flare landfill gas. More and more landfill sites are considering implementing the collection and use or flaring of landfill gas.

There remains a number of other larger landfills that should be taking steps to control landfill gas to reduce greenhouse gas and trace contaminant emissions, and take advantage, if practical, of energy generation opportunities.

Existing Regulations

Contact:

Larry Wilcox
Senior Engineer
Ministry of the Environment
Integrated Environmental Policy Division
Waste Management Policy Branch
135 St Clair Avenue West
Floor 7
Toronto Ontario
M4V 1P5
Phone: (416) 314-7876

Other Information:

Ontario's existing regulations requiring mandatory landfill gas collection and controls are set out in section 15 of O. Reg. 232/98. O. Reg. 232/98 came into effect in 1998 and requires new or expanding sites larger than 3 million cubic metres to collect and use or flare (i.e. burn) landfill gas.

O. Reg. 232/98 can be viewed by clicking the following hyperlink:

http://www.e-laws.gov.on.ca/DBLaws/Regs/English/980232_e.htm

Public Consultation:

This proposal was posted for a 90 day public review and comment period starting August 09, 2007. Comments were to be received by November 07, 2007.

All comments received during the comment period are being considered as part of the decision-making process by the Ministry of the Environment.

Please Note: All comments and submissions received have become part of the public record.

Add Notice into My Watch List

Ontario

MINISTRY OF AGRICULTURE, FOOD AND RURAL AFFAIRS

Producing Biomethane and Renewable Natural Gas (RNG) from Farm and Food-Based Biogas Systems

Table of Contents

Introduction

This infosheet describes the potential opportunities related to the production and utilization of biomethane and renewable natural gas from biogas systems at farms and food processing facilities in Ontario. There is already one biogas system providing biogas to the natural gas pipeline in Canada (Figure 1), and a few more across North America and Europe. This infosheet explores some of the initial implications of engaging in these opportunities.

What is Biomethane or Renewable Natural Gas?

Biomethane is a gaseous fuel that contains between 55% to 99% methane, and is produced from biogas generated through the anaerobic digestion of organic materials, or from landfill gas production. Biomethane is biogas that is cleaned by removing contaminants such as hydrogen sulphide and moisture. In addition, biomethane may be "upgraded" to almost pure methane by eliminating carbon dioxide (CO_2). Methane is the primary ingredient in conventional natural gas. Renewable natural gas (also known as RNG) is biomethane that has been cleaned to meet natural gas pipeline quality standards.

For more information on the basics of biogas production on the farm, read the OMAFRA Factsheet Anaerobic Digestion Basics (Order no. 07-057).

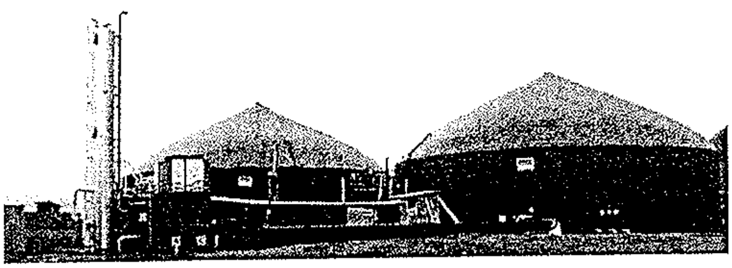

Figure 1. A farm-based biogas system producing renewable natural gas in British Columbia. The system that upgrades the gas to meet natural gas standards is located on the left hand side of picture.

How Much Energy is in Biomethane From Manure?

It is estimated that there is enough fuel from the manure from one milking cow to drive a pick-up truck roughly 5000 km per year. This calculation assumes that the manure from a milking cow (including its offspring) produces roughly 1350 cubic metres of biogas per year, and that 60% of the biogas is methane.

Can Biomethane Be Produced on a Farm?

Biomethane is currently being produced at the Catalyst Power facility at a dairy farm near Abbotsford, British Columbia. The biogas system became operational in 2010. Biogas is produced in four anaerobic digester tanks which are fed liquid manure, corn silage, and food wastes from the nearby communities. Biogas is upgraded to natural gas quality on a continuous basis, producing about 110,000 GigaJoules (GJ) per year. The upgraded gas (RNG) is sold to the local gas utility company.

How is Biomethane Used?

Once biomethane has been created it can be managed and used as a replacement for natural gas or other gaseous fuels. Some of the common uses for biomethane include:

- **Injection into the natural gas pipeline:** Biomethane that has been upgraded into RNG must meet specific minimum or maximum levels for certain gases, moisture, and other constituents in order to be added into the pipeline. It must be pressurized, and it must meet a variety of safety and metering rules. Once RNG is added to the pipeline it is considered to be no different from natural gas. Depending on contractual models, it could be purchased by an end user, or by the gas utility. In Ontario, the process of pipeline injection is regulated by the Ontario Energy Board.

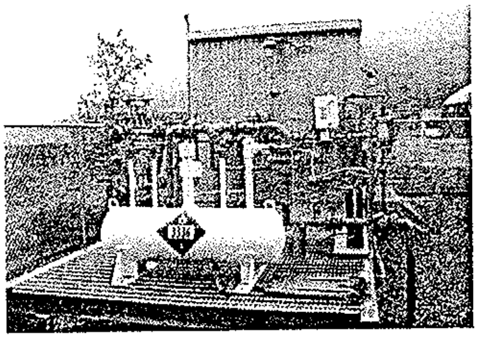

Figure 2. Injection system used to pump RNG into a natural gas line at a farm-based biogas system

- **Compressed for Non-pipeline Customers:** Biomethane or RNG can be compressed as a gas and stored in pressurized containers to be used on-site or at remote locations. This may be attractive to fuel users who currently have more expensive fuel alternatives, for instance, when heating livestock facilities or greenhouses. In Europe compressed RNG from biogas is brought to vehicle fuelling stations in trailer-mounted pressurized containers. Local users of the fuel have vehicles designed or converted for natural gas use. Other European sites have RNG from a local biogas system piped directly to a nearby fuelling station without using the natural gas pipeline.
- **Biomethane:** In some cases, biogas with only 60% methane content can be used to replace other fuels. To do so, some contaminant gases and water vapour must be adequately removed from the biogas. The remaining 40% of gas volume (other than methane) is made up primarily of carbon dioxide, meaning the fuel has a lower energy density than pure methane. This can be effectively accounted for in a properly designed fuel system, appliance, or engine. Figure 3 shows a prototype agricultural tractor that is designed to run on 60% methane biogas. The engine can operate on a blend biogas and diesel (called a dual fuel system). The prototype gets 70% to 80% of its 110 hp from cleaned biogas (containing 60% methane and 40% carbon dioxide). Other prototype tractors from Steyr (Case) and John Deere have also been demonstrated running on biogas.

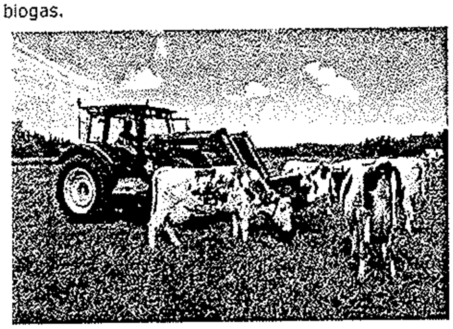

Figure 3. Valtra's prototype biogas tractor that runs on farm-based biogas. Note the pressurized biogas storage system on lower side of tractor. Photo courtesy of Valtra and AGCO.

Why Consider Renewable Natural Gas or Biomethane?

With the recent breakthroughs in shale gas production, natural gas prices have dropped and may remain low compared to the prices in recent years. Despite this, there are a number of reasons why RNG production may be considered at biogas systems today:

- **RNG is not a fossil fuel.** Fuel consumers may desire to purchase a fuel that has a lower greenhouse gas footprint than conventional fossil fuel-based natural gas. For instance, in 2011 an Ontario food processor signed an agreement to purchase landfill gas RNG via the natural gas pipeline so that its cookie production facility could be fully fuelled from a renewable source;

- **Efficient use of biogas.** When biogas is generated for other purposes (waste management, wastewater treatment), upgrading biogas to RNG allows for an efficient use of the energy in the fuel, resulting in nearly all of the energy in the gas being converted for energy purposes. In comparison, using biogas or RNG in a cogeneration system to produce electricity may result in losses and inefficiency if there is not an on-site use for excess heat from a cogeneration system;
- **Availability of gas line connection.** A biogas system may be located in an area that does not have sufficient electrical grid capacity to establish or expand the facility. The project developer might consider whether the natural gas line has capacity to use the RNG, or whether other gaseous fuel users might want to purchase the gas;
- **Cost effectiveness.** In most cases it is not possible to produce RNG at a cost directly competitive to current natural gas prices. However, in some cases RNG use may be competitive to other sources of energy such as electricity, gasoline and diesel. This may be applicable at locations that are not currently serviced by conventional natural gas. Using RNG may also be a good way to keep using existing natural gas fuelled equipment (such as a boiler or furnace) but gaining the advantages of using a renewable fuel, such as reducing reliance on fossil fuels.

Environmental and Societal Benefits of Using RNG from Farm and Food-Based Biogas Systems

In addition to the climate change benefits associated with using methane from a non-fossil fuel source, when markets for RNG can be found, the operation of farm and food-based biogas systems results in benefits that include:

Material treatment:

- **Emissions reduction:** the storage, land application, or disposal of untreated manure and food waste can produce greenhouse gas or smog-forming emissions. By harvesting the carbon in a biogas system and using it as RNG, emissions from conventional processes are avoided.
- **Odour reduction:** manure and food waste used in biogas systems might otherwise have contributed to odour emission when handled in other conventional manners. Digesting these materials in a biogas system results in odour reduction, contributing to reduced nuisance issues in rural and urban-fringe areas;
- **Pathogens:** operating a biogas system with manure as a primary input results in a reduction in pathogens (such as E .coli). Reducing pathogens at the source adds another barrier to reduce risk for surface and groundwater drinking sources, contributing to source water protection objectives in the province;

Waste management for food wastes and by-products:

- **Avoid land filling:** By using food waste as a biogas input, food waste and food processing by-products that are currently land-filled can be diverted. While a portion of the methane emissions from landfills can be captured once a landfill is capped, it is much more efficient to harvest this methane directly and fully in a biogas system.
- **Reduced waste management costs for the food sector:** Directing food waste and by-products to biogas systems will in general result in lower handling costs for food waste compared to other management approaches (landfill, compost, and land-application). Conventional waste management approaches can be expensive since food wastes can be wet, sloppy, odorous, and may be generated through the winter (requiring storage solutions). Biogas systems have the ability to deal with all of these issues and potentially be a good destination at a lower cost. The result is that Ontario's food sector can avoid some costs and stay competitive with other jurisdictions.
- **Recycling of nutrients and carbon to the land:** When food wastes are digested in biogas systems and the digestate effluent is returned to agricultural fields and spread like manure, the result is that agricultural nutrients like nitrogen, phosphorous and potassium are returned to the soil. The indigestible carbon component in food wastes will also contribute to soil health, building up organic matter. This is an improvement compared to land filling or sewer discharge of food wastes, where these nutrients and carbon are lost.

Rural economic development:

- **Local fuel production:** Instead of sourcing energy from other jurisdictions, local companies become generators of fuel, meaning that energy dollars are kept in the province;

- **Local synergies:** Locating biogas systems near the waste sources or near the destination for effluent end products means that jobs, transportation and tax revenue stay local. This approach closes the loop on the farm and food production system.

Building a Biomethane or RNG System On-Farm

A farm-based biogas system built for biomethane or RNG production will appear in most aspects like conventional biogas electricity-based systems. There are a few key differences apparent at RNG biogas systems (beyond the absence of electricity generation equipment):

- **Location near a natural gas line:** For systems supplying RNG to the natural gas pipeline, construction of the facility within piping distance of natural gas pipeline will be necessary. Throughout many areas of rural Ontario there is no natural gas service, therefore pipeline injection may not be viable for many livestock farms simply due to their location.
- **Large size:** In general, the upgrading technology currently on the market requires a higher gas production rate than would be available from most farm-based biogas systems built in Ontario today. In Ontario, building a sufficiently large system may be achieved with blends of off-farm materials, energy crops, and/or mixing manure from multiple farms to produce enough biogas.

Alternately, perhaps models can be developed for non-pipeline end use of biomethane such as vehicle refuelling or replacement of gaseous fuel via compressed gas trailer transport. Regulatory approval processes will have to be fleshed out for such systems. In addition, the following factors may be applicable for on-farm biomethane system construction and operation:

- **Seasonal variability:** There are few consistent fuel users with constant daily demands. The biogas system may have to respond to daily or seasonal variations in fuel demand by changing input feeding rates, or by identifying alternative biogas uses to manage excess biogas.
- **Increased biogas storage:** It is likely that there will be daily variations in fuel usage, whether the gas end user is a food processor or a fleet of vehicles, accounting for weekends and holidays and changes in business activities. Pressurized or non-pressurized gas storage may be required at the biogas system or at the end user site to facilitate the ongoing daily production of biogas.

Conclusions

This infosheet provides an introduction to biomethane and renewable natural gas production. These potential markets for biogas may be a new pathway to capture the environmental and economic benefits associated with farm and food-based biogas systems. Work remains to be done to demonstrate the economic value chain, technical needs, regulatory implications, and viability of these approaches.

For more information:
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Local: (519) 826-4047
E-mail: ag.info.omafra@ontario.ca

Ontario

MINISTRY OF AGRICULTURE, FOOD AND RURAL AFFAIRS

Overview of Ontario Biogas Systems Financial Assistance Program

Objectives

The program, which ran from September 2008 to March 2010, aimed to:

- Increase the number of biogas systems built in Ontario
- Increase utilization of products and byproducts in biogas systems
- Improve biogas utilization
- Decrease greenhouse gas emissions
- Increase knowledge amongst potential biogas stakeholders
- Increase the number and experience of biogas technology providers.

The Ontario Biogas Systems Financial Assistance Program is now closed and the ministry will continue to support the newly established biogas sector through various projects.

Successes

A total of $11.2 million was used to grow a biogas sector in Ontario through the development of biogas systems on farms and at food processing businesses. Up to 27 biogas systems are expected to be built or under construction in Ontario by the end of the program.

- Biogas Projects Funded
- Ontario Biogas Industry Contact List
- Factsheets and Technical Information for Biogas Operators
- Biogas system financing and funding opportunities

The program has contributed significant assistance to various industry projects, including:

- helping to simplify electrical grid connection requirements
- supporting a biogas industry group - the AgriEnergy Producers' Association of Ontario
- conducting studies of biogas yields from Ontario feedstocks
- holding four training courses and several workshops
- providing other sector resources, such as equipment loans.

The ministry has contributed significant funding, resources and training to establish the biogas sector and is now continuing to support it through various projects, including:

- training opportunities for safe, operational, and profitable systems
- promoting technologies and knowledge transfer
- encouraging biogas system technology improvements
- improved opportunities to reutilize organic materials

Benefits of Biogas Systems

- Biogas systems benefit Ontarians by reducing greenhouse gas emissions, producing peak and non-peak renewable power, and improving waste diversion rates, while providing other environmental benefits such as pathogen reduction and odour control.
- Biogas systems treat manure and other organic materials that reduce pathogens and odours.
- Biogas systems can produce clean, renewable energy that reduces greenhouse gas emissions.
- Biogas systems produce a new revenue stream for farm and food processing operations.

For more information:
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Local: (519) 826-4047
E-mail: ag.info.omafra@ontario.ca

E.B.R.O. 410-III
E.B.R.O. 414-II
E.B.R.O. 417

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1980, Chapter 332;

AND IN THE MATTER OF Reasons for Decision of the Ontario Energy Board dated March 23, 1987, in E.B.R.O. 410-II, 411-II, 412-II concerning an inquiry into and determination of certain matters relating to contract carriage arrangements pursuant to subsection 13(5) and section 19 of the said Act;

AND IN THE MATTER OF an application by The Consumers' Gas Company Ltd. to the Ontario Energy Board, under section 19 of the said Act, for an Order or Orders approving rates and other charges for the sale, transportation and storage of gas.

BEFORE: J. C. Butler
Vice Chairman and
Presiding Member

C. U. Craddock
Member

January 22, 1988

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TABLE OF CONTENTS

4. OTHER ISSUES

Ontario Suppliers and Company Production

4.1 Consumers' has access to Ontario gas supplies principally from two sources, Pembina and the Company's own production. Prior to deregulation, the Company contracted with Pembina to buy gas at a price referenced to the TCPL CD-100 rate which contained, as an underlying commodity cost of gas, an administered Alberta border price. The Company's own production was a regulated activity priced on a cost of service basis. Now there is no administered Alberta border price and Company production has been removed from the umbrella of regulation.

4.2 The Company proposes to pay an average price of $\$114.50/10^3m^3$ for all volumes purchased from Pembina. This approximates 99 percent of the expected ACQ delivered price, net of discounts. The Company further proposes that its own production should be treated like Pembina's in all matters including price.

4.3 Counsel to Board Staff argued that the price proposed for Company and Pembina production gas is significantly higher than true market value, citing several "benchmark" prices including those for broker gas, discretionary purchases, and the price paid by Union for local production. He also argued that the Board should view Alberta and Ontario gas in the same manner, since both are simply domestic supplies.

4.4 Energy Probe submitted that if Company production is treated like that of Pembina, there is virtually no incentive for the Company to bargain hard with Pembina.

4.5 Consumers', in reply, reiterated its belief that Ontario production has advantages over extra-provincial supplies, namely, it is completely under Ontario jurisdiction and therefore not subject to Alberta rules or restrictions, it is independent of the TCPL system, and it is a firm guaranteed supply. The Company argued that Union does not have any local producers of comparable size and quality of service. Negotiations with Pembina were guided by the principle of linking price to quality of service, and the Company alleged that on that basis its expected delivered ACQ price net of discounts was the appropriate benchmark.

Board Findings

4.6 The Board accepts the pricing of Pembina production by reference to the Company's delivered ACQ price net of discounts. Although there may be cheaper gas available at this time from sources outside Ontario, the Board does not find it appropriate to value Ontario production without regard for quality of service factors. Moreover, given the volume of Pembina production, the Board does not regard the price paid by Union to its Ontario suppliers, which are generally much smaller, as an appropriate benchmark. There is no evidence to support any suggestion that the Company's negotiations with Pembina have been other than at arms' length.

4.7 The Board also finds that it is reasonable for the Company to value its own production like Pembina's. These are similar supplies from similar locations with similar production considerations. The Pembina price negotiations provide the most reasonable proxy for a market price for Company production at this time.

4.8 At this stage in deregulation, the Board finds that maintaining long term supply options indigenous to Ontario is in the broader public interest. The Board will not, therefore, either shut in or undervalue Ontario gas supplies by adopting an inflexible position in favour of "lowest price regardless of consequences".

4.9 The Board therefore accepts an average price of $\$114.50/10^3m^3$ for both Pembina and Company-owned production. The Board will require Consumers' in future hearings to justify the volumes taken from these sources against other options available.

Winter Peaking Service

4.10 The Company has an agreement with TCPL to purchase 40,000 10^3m^3 of Winter Peaking Service (WPS) during fiscal 1988. WPS forms part of Consumers' peak day coverage and is available for delivery from November 1 to April 15. Under WPS the supplier is obligated to deliver up to one-tenth of the annual contracted volume on any day at the buyer's option. Thus, TCPL is obligated in fiscal 1988 to have sufficient deliverability on standby to provide Consumers' with up to 4,000 10^3m^3/per day for up to 10 days.

IN THE MATTER OF

TERASEN GAS INC.

BIOMETHANE APPLICATION

DECISION

December 14, 2010

BEFORE:

D.A. Cote, Panel Chair/Commissioner
A.A. Rhodes, Commissioner
L.A. O'Hara, Commissioner

TABLE OF CONTENTS

Page No.

TABLE OF CONTENTS

1.0 EXECUTIVE SUMMARY

On June 8, 2010 Terasen Gas Inc. filed an Application for approval of what it describes as an end-to-end business model encompassing the purchase of biogas and/or Biomethane for sale to its customers. The Application was filed against the backdrop of the continued evolution of British Columbia's energy policy. The most recent addition, *The Clean Energy Act,* received Royal Assent on June 3, 2010 and, in the view of the Applicant, has given renewed and heightened importance to its role in the development of renewable resources, the reduction of GHG emissions, the reduction of waste through the use of biogas and biomass as well as its role in promoting energy efficiency. Further, Terasen has noted that federal, provincial, regional and municipal governments have all become increasingly focused on climate change and the impact of pollution and have adopted policies to favor renewable energy forms as key to solving environmental challenges.

Terasen Gas is developing a number of initiatives which it believes are aligned with BC Government Policy and the *Clean Energy Act.* These are outlined in its 2010 Long Term Resource Plan that is currently before the British Columbia Utilities Commission. The Biomethane Service Offering Application is the first of these initiatives that has come before the Commission. This Application is made up of three components:

- The Biomethane Supply Model which addresses the acquisition of a reliable supply of biogas.
- The Biomethane product offering which consists primarily of a rate offering allowing for the notional sale of Biomethane to Terasen customers on a voluntary basis.
- The cost allocation and recovery model addressing the recovery of costs for the product offering from the various customer groups.

This Biomethane Service Offering which includes all elements of the biomass model has been referred to as the Biomethane Program or Program within this Decision. Terasen's Application seeks approval of a number of Orders encompassing rates, cost recovery, supply and post implementation review which are related to the Program. Key among these are the following:

approval of two projects, the Catalyst Project in Abbotsford, BC and the Columbia Shuswap Regional District Project in Salmon Arm, BC; the allocation of costs between all non by-pass customers and voluntary Biomethane gas purchasing customers and a set of criteria allowing for the filing of future supply contracts.

In its review of the Application, the Commission Panel raised and examined a number of issues in reaching the determinations made in this Decision. The first group of these includes the following: the alignment with British Columbia's energy objectives and Provincial Government policy, the adequacy of supply for these and future Projects and the level of customer demand for this type of program. On the basis of this examination, the Panel is satisfied the Program is in alignment with both British Columbia's energy objectives and Provincial Government policy and there is sufficient demand and supply to justify moving forward. Accordingly, the Panel has determined the two Projects are in the public interest and has approved both of them as well as the related capital costs. However, the Panel in reaching this determination has noted that it would be prudent for TGI to thoroughly test the proposed model in the marketplace before reaching a conclusion as to its full market potential.

The second group of issues is related to how the Biomethane Program will work and includes the following:

- Terasen's proposed role in the biogas upgrading process;
- The criteria for future projects;
- The risk of stranded assets and other project risks;
- Principles for cost allocation and recovery; and
- Post implementation review and reporting.

With respect to Terasen's proposed role in the upgrading process, the Panel has made no finding on the acceptability of this and directs that the upgrading business be sufficiently distinct so as to be severable if the Commission were to determine that this function should be conducted through a separate entity in the future. Concerning the criteria for future projects to be approved on a streamlined basis, the Panel has added criteria limiting the total production of Biomethane for all projects to 250,000 GJ per year during the test period and set a maximum commodity price at $15.28 per GJ. In addition, the Panel has approved the cost allocation methodology as proposed by Terasen as reasonable and in the public interest. Finally, the Commission Panel directed the post implementation review and reporting period be reduced from the requested five years to two years.

In this Decision, the Commission Panel has allowed Terasen Gas to move forward with a Biomethane Program on a test basis for a two year period. In introducing limitations on scope and a term for the test, the Panel believes that Terasen will learn valuable lessons which can be applied to the development of a model which will sustain the Program over the long term. It believes that taking this approach is prudent and in the best interests of TGI ratepayers.

2.0 INTRODUCTION

This Application is submitted by Terasen Gas Inc. (Terasen, Terasen Gas, TGI or the Company) for approval to introduce an end-to-end business model for the acquisition of a Biomethane gas supply and the sale of this renewable energy to its customers.

2.1 Application

TGI and its affiliated companies sell and deliver natural gas to residential, commercial and industrial customers throughout British Columbia (BC). They provide service to 940,000 customers and which represents over 95 percent of gas users in the Province. Their operations are subject to regulation by the British Columbia Utilities Commission (Commission, BCUC).

By Application dated June 8, 2010 Terasen applied for approval of a Biomethane Service Offering and Supporting Business Model, for approval of a Salmon Arm Biomethane Project and for one in the Abbotsford area (the Application). Terasen Gas proposes to develop an initial supply of Biomethane from two projects:

- a farm in Abbotsford, BC where a project partner will collect agricultural waste and use anaerobic digestion and upgrading technology to develop Biomethane which will be delivered to Terasen for injection into the distribution system (the Catalyst Project); and
- a landfill project in Salmon Arm, BC where raw biogas will be produced in a landfill by a project partner and then upgraded to pipeline quality Biomethane by Terasen (the CSRD Project, or the Salmon Arm Project).

Biogas is a gas substantially composed of methane that is produced by the breakdown of organic matter (biomass) in the absence of oxygen. Biomethane is renewable energy and refers to biogas that has been upgraded to primarily methane by the removal of other constituents, so that it is safely interchangeable with natural gas in the distribution and transmission system. (Exhibit B-1, p. 7)

The end-to-end business model for a Biomethane program proposed by Terasen in the Application has three parts encompassing models for the acquisition of a supply of biogas, the sale of Biomethane to its customers and the allocation and recovery of costs.

Terasen states that market research suggests there is a strong desire on the part of customers to purchase renewable clean energy. It further states that the data presented in the Application supports the position that demand for the product will exceed the capability of the initial projects to supply it. This has resulted in Terasen proposing a phased approach which it states is both flexible and scalable allowing supply and demand to be balanced. (Exhibit B-1, pp. 1-3) Worthy of note is a letter from the Assistant Deputy Minister of Energy, Mines and Petroleum Resources, expressing the government's support for the Biomethane Service Offering. In it he states that:

> "[t]he objectives of this proposal align with the policy actions of the BC Energy Plan, the BC Bioenergy Strategy and the British Columbia energy objectives of the *Clean Energy Act* (the Act), particularly the objectives in section 2(g) "to reduce greenhouse gas emissions" and section 2(j) "to reduce waste by encouraging the use of waste heat, biogas and biomass." (Exhibit E-1)

2.2 Orders Sought

TGI seeks Commission approval of a number of orders pursuant to the *Utilities Commission Act* R.S.B.C. 1996 c. 473 (the *Act*, *UCA*). Listed in their entirety in Appendix A to this Decision, they include the approval of rate related orders, cost recovery related orders for both voluntary participant customers and all non-bypass customers, supply project related orders and post implementation review orders.

2.3 Regulatory Process

The Regulatory Process is described in detail in Appendix B. Nine organizations registered as Interveners for the Application. They are as follows:

- Catalyst Power Inc.
- BC ARD Corporation
- BC Bioenergy Network
- British Columbia Power and Hydro Authority (BC Hydro)
- British Columbia Old Age Pensioners' Organization *et al* (BCOAPO)
- Elemental Energy Inc.
- Commercial Energy Consumers Association of British Columbia (CEC)
- BC Sustainable Energy Association (BCSEA)
- BP Canada Energy Company

Among these the BCOAPO, CEC, BC Hydro and BCSEA actively participated in some or all of the Processes.

2.4 Context and Key Issues

TGI is seeking approval for the introduction of an end-to-end business model encompassing the acquisition of a supply of Biomethane and the sale of this renewable energy to its customers. As a starting point, Terasen has proposed that the supply of Biomethane be developed from two initial projects which were broadly described earlier in Section 2.1. These projects represent two different approaches to securing raw biogas and then upgrading it to allow it to be injected into the natural gas pipeline system. The first of these projects, the Catalyst Project, represents the traditional supply side management process for Terasen where the product has been purchased in its final form. The second, the CSRD Project, represents a significant departure from this as Terasen moves up the supply chain to provide the biogas upgrading service role. The Catalyst Project and the CSRD Project will be collectively referred to as "the Projects", in this Decision. The Biomethane Service Offering including all elements of the business model will be referred to as the Biomethane Program or Program.

A significant part of the Application is centered upon an examination and justification of the Projects and the resale of Biomethane from them. However, the Application goes much further in that it proposes a model which the Company will use as a basis for development of a broader Biomethane product offering in the future. Included in the model are the following:

- A set of future project selection criteria which, when satisfied, will allow for a streamlined regulatory process.
- A departure from the traditional supply side management processes utilized by Terasen.
- A set of principles governing the allocation of costs and their recovery from ratepayers.

It is further proposed that this model be reviewed through a post implementation report and workshop, which is contemplated to occur five years following the launch of the initial project.

Given the potential size and scope of the initiative being proposed by Terasen, the Commission Panel needs to consider issues far beyond those needed to reach a determination on the Projects. In reaching its Decision, the Panel also needs to consider the impact of the alternative positions it may take on the issues arising and assess the suitability of the model and whether changes are necessary to protect the public interest in the period which lies ahead. In what follows, the Panel will provide an outline of the Program before examining each of the key issues it believes to be important in reaching a determination as to whether the Application is to be accepted and whether changes to the proposed model are required. Accordingly, following a description of the key elements of the Program, the Panel will initially examine the following issues:

- How the Program aligns with British Columbia energy objectives and Policy;

- The adequacy of supply of biogas;
- The level of customer demand for the Projects and others like them.

The Panel will then examine some of the broader issues related to the model including:

- Terasen's proposed role in the biogas upgrading process;
- The criteria for future projects;
- The risk of stranded assets and other project risks;
- Principles for cost allocation and recovery; and
- Post implementation review and reporting.

3.0 PROJECT DESCRIPTION

3.1 Overview

The *Clean Energy Act,* S.B.C. 2010 c. 22 *(CEA)* received Royal Assent on June 3, 2010. In Terasen's view it has given a renewed and heightened importance to its role in developing renewable resources, reducing GHG emissions, reducing waste by using biogas and biomass as well as promoting energy efficiency. The Commission Panel considers the following British Columbia energy objectives included in section 2 of the *CEA* are germane to the Application:

(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;

(g) to reduce BC greenhouse gas emissions

(i) by 2010 and for each subsequent calendar year to at least 6 percent less than the level of those emissions in 2007....;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(j) to reduce waste by encouraging the use of waste heat, biogas and biomass.

In addition, federal, provincial, regional, and municipal governments are increasingly focused on climate change and pollution, adopting policies in favour of renewable forms of energy as a key part of the solution to environmental challenges. The Provincial Government has also explicitly stated its support for biogas project development in the 2008 Bioenergy Strategy document. (Exhibit B-1, Appendix B-7, p. 8) Moreover, Terasen notes that many of the logical partners in the development of Biomethane projects are municipalities or regional districts because landfills and sewage treatment facilities owned and/or operated by them are often excellent sources of raw biogas. Terasen Gas submits the capture of biogas, and its upgrading to pipeline quality Biomethane, can help local governments generate revenue and meet the municipal GHG emission targets by way of the beneficial use of waste methane rather than flaring it. (Exhibit B-1, p. 27)

The end-to-end business model proposed by the Company is made up of the three components listed below and described subsequently in more detail:

- *The Biomethane supply model* - which addresses the logistics of acquiring a reliable supply of biogas, safely and reliably upgrading it to Biomethane and injecting it into TGI's distribution system;
- *The model for offering Biomethane product to customers* - which consists primarily of the formulation of a rate offering to allow the notional sale of Biomethane to those Terasen customers who are willing to pay a premium price for this product; and
- *The cost allocation and recovery model* - which addresses the related cost recovery of this product offering from various customer groups. (Exhibit B-1, p. 2)

3.1.1 Supply of Biomethane

Terasen states that its partners will be responsible for the collection of raw material and the facilities required for production of biogas. However, for the process to upgrade biogas into Biomethane TGI has introduced two models. In the first model, Terasen will negotiate a contractual relationship to purchase upgraded Biomethane from project partners, providing these independent operators can meet Terasen's financial and technical standards. In the second, Terasen's preferred model, it will own and operate the upgrading facilities "to ensure reliability, safety and the continuous flow of product from the Biomethane supply project to the customer." In all cases, Terasen proposes to retain control of the interconnection facilities to control the injection of Biomethane into the distribution system. (Exhibit B-1, p. 2)

3.1.2 Sale of Biomethane to Customers

Based on its market research, Terasen believes its customers have a "significant interest in purchasing Biomethane from Terasen Gas as an environmentally superior option to conventional natural gas."

Terasen proposes to take a phased approach to launch this program in recognition of the limited availability of Biomethane at this time. The first phase of the Biomethane product offering (the Offering) will involve making a blended Biomethane product available to residential customers starting with a blend of 10 percent Biomethane and 90 percent conventional natural gas. Phase two will involve launching the same 10 percent blend for small and large commercial customers on January 1, 2012. Terasen also plans to sell Biomethane to on-system transport customers and off-system wholesale customers. Eventually, Terasen's goal is to expand its offerings as the Program matures and new supply sources are developed. (Exhibit B-1, p. 3)

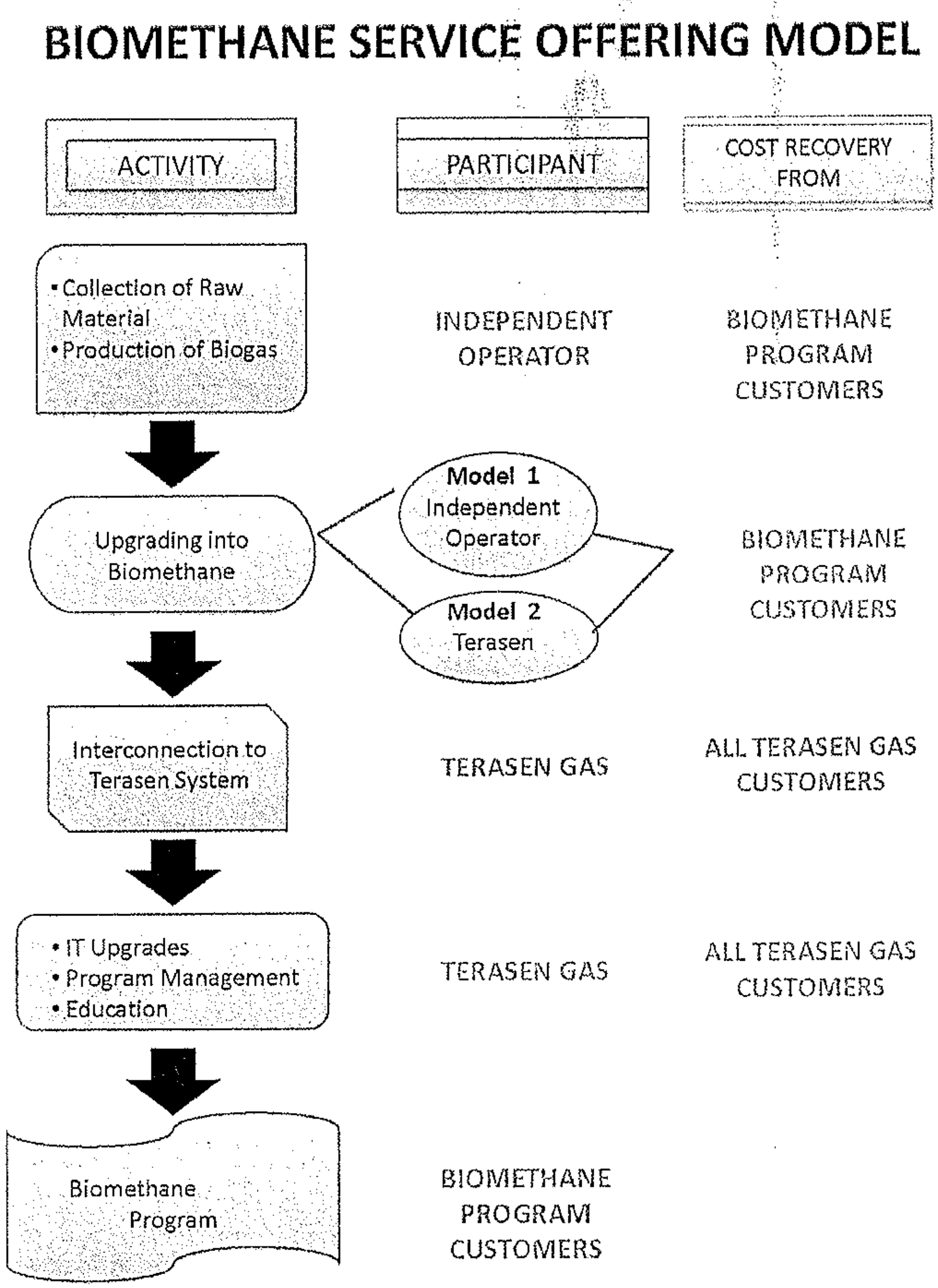
3.1.3 Cost Allocation and Recovery

Terasen Gas states that the Offering will be a premium product and accordingly customers choosing to participate will have to pay a higher price to reflect the actual higher cost of the Biomethane. Terasen proposes the following cost allocation and pricing principles for its new end-to-end business model:

- *Customers should bear the cost of the energy they choose to consume.* Therefore, Terasen intends to aggregate the biogas acquisition and upgrading costs and proposes to recover them as a commodity cost for Biomethane from those customers who opt for the Program. In those cases where Terasen buys the upgraded Biomethane from an independent operator that cost would be included as a commodity cost.
- *Costs associated with making the Biomethane service offering available to all customers should be borne by all non-bypass customers.* Terasen envisages these costs to include quality monitoring, IT upgrades, program management and customer education with some marketing involved.

(Exhibit B-1, p. 3)

The Biomethane Service Offering Model is depicted for the reader's benefit in the diagram below.[1]



[1] Diagram was created from information in Exhibit B-1

3.1.4 Notional Delivery

Terasen Gas proposes what it describes as a "notional delivery" of Biomethane. The Company explains that "notional delivery" is a concept used in the trading of commodities, where delivery is notional rather than real. Terasen is of the view that the interchangeability of Biomethane with conventional natural gas allows for this concept to be used in the Application, as the end user will not be able to differentiate between the products. Terasen draws the analogy between the residential Customer Choice Program where gas marketers are responsible for delivery of natural gas to the system, but their particular customers may not actually receive those molecules of natural gas, as individual molecules are not tracked. (Exhibit B-1, p. 15)

The Commission Panel has some concern about the applicability of notional delivery to the Offering. The Application is premised on the fact that Biomethane is a different product than natural gas with different carbon properties. Terasen is asking customers to agree to pay a premium for a different and arguably superior product which the customer may or may not receive. It is important that Terasen be able to communicate this distinction as part of its marketing program so there is no misunderstanding on the part of the consumer.

3.2 Outline of Projects

TGI has included two supply projects in the Application for the Commission's consideration. They represent concrete examples of the two supply models described earlier. The Projects are described in more detail below.

3.2.1 Catalyst Project

The first project brought forward by Terasen is an agricultural waste to Biomethane project located in Abbotsford, BC. The project partner is Catalyst Power Incorporated (Catalyst). In this project, which represents the first supply model, Terasen is purchasing upgraded Biomethane with a relatively small capital investment required only in distribution main and interconnection facilities.

Highlights of this Project and key provisions of the supply agreement are summarized as follows:

Highlights of the Project:

- Catalyst investment in the digestion, gas collection and upgrade technology: $ 5 Million; and
- Terasen investment as shown below:

Table 3-1: Capital Cost Summary

Item	2010 Estimate
Interconnection (valves, meter, regulator)	$ 77,300
Quality Monitoring	282,500
Main and Main Connection Costs	227,900
Total	**$ 587,700**

Source: Exhibit B-1, p. 100

The injected Biomethane is forecast to displace the quantity of natural gas required to serve more than 875 households annually, based on Lower Mainland typical household demand of 95 GJ per year, and thus reduce GHG emissions by at least 4,000 tonnes annually based on the minimum projected supply. Assuming a 10 percent blend, this converts to 8,750 customers. The range of expected annual GHG emissions associated with the Catalyst Agreement is shown below.

Table 3-2: Annual CO_2e reduction

	Minimum Contract Amount	Maximum Contract Amount
Gigajoules ("GJ") of Natural Gas displaced	84,000	180,000
Tonnes of CO_2e per gigajoule	0.050	0.050
Tonnes of CO_2e reduced	4,200	9,000

Source: Exhibit B-1, p. 101

Key provisions of the Catalyst supply agreement:

- Quantity: Minimum annual delivery of 84,000 GJ;
- Term: 10 years;
- Price: As negotiated with Catalyst, falls within the range of expectations;
- Quality: Terasen Gas quality specifications; and
- Other: The non-performance definition and excuse from non-performance for maintenance in the agreement strike a balance between committing both Catalyst and Terasen to deliver and accept pipeline quality Biomethane and allow both companies sufficient flexibility to solve minor operational issues which may arise.

A number of measures have been incorporated into both the agreement and the facilities themselves to mitigate a range of potential risks. These risks are further addressed in Sections 4.7 and 4.9.

Terasen states that Catalyst has conducted significant public consultation in its efforts to get the necessary agriculture and land use approvals in place to allow the construction and operation of an anaerobic digester and biogas upgrading system on the site. (Exhibit B-1, pp. 94-105)

3.2.2 CSRD Project

This biogas project will be located at the regional landfill within the city limits of Salmon Arm, BC. The project partner is the Columbia Shuswap Regional District. Terasen states that in this case it will be purchasing raw biogas and investing in upgrading equipment along with the distribution main and interconnection facilities, which include gas quality monitoring, pressure regulation and odorizing. Highlights of the proposed project and key provisions of the supply agreement are summarized as follows:

Highlights of the Project:

- CSRD investment in the landfill gas capture, collection and flare system: $ 4.8 Million
- Terasen Gas investment in upgrading and interconnection facilities as shown below.

Table 3-3: Capital Cost Summary

Item	2010 Estimate
Interconnection (valves, meter, regulator)	$ 395,500
Quality Monitoring	242,000
Main Connection Costs	45,100
Upgrading Plant (Installed)	1,621,800
Total	**$ 2,304,400**

Source: Exhibit B-1, p. 89

It should also be noted that in this Project funding from the provincial government's Innovative Clean Energy (ICE) fund and the BC Bioenergy Network (BCBN) of some $500,000 will reduce the Terasen capital expenditure to $ 1.8 Million.

The injected Biomethane will displace the quantity of natural gas required to serve more than 300 households annually, based on North Okanagan typical annual household demand of 100 GJ, and thus reduce GHGs by approximately 1,500 tonnes per annum as shown in the Table below.

Table 3-4: Annual CO_2e reduction

	Expected Contract Amount	Maximum Contract Amount
Gigajoules ("GJ") of Natural Gas displaced	30,000	45,000
Tonnes of CO_2e per gigajoule	0.050	0.050
Tonnes of CO_2e reduced	1,500	2,250

Source: Exhibit B-1, p. 91

Key provisions of the supply agreement:

- Quantity: 30,000 GJ per annum;
- Term: 15 years, with a yearly automatic renewal after the first 15 years;
- Price: As negotiated with CSRD, falls within the range proposed as an economic test for future projects;
- Quality: a raw gas quality specification; and
- Other: CSRD is required to make commercially reasonable efforts to maintain equipment and supply the best quality gas possible.

Again, a number of measures have been incorporated into both the agreement and the facilities to mitigate a potential supply risk, operational risks and risk of stranded assets. These are addressed in further detail in Sections 4.7 and 4.9.

Finally, Terasen states the CSRD has indicated that there are no outstanding claims or concerns in the planned project area. (Exhibit B-1, pp. 83-94)

3.3 Criteria for Future Projects

One of the numerous approvals Terasen is seeking is an order that future supply contracts for the purchase of biogas or Biomethane which meet the criteria described in the Application meet the filing requirements in sections 71(1)(a) and 71(1)(b) of the *UCA*. It states that an early adoption of this framework will facilitate growth of the supply industry "by establishing clear and achievable parameters for our potential supply partners." This Section addresses the criteria which have been proposed.

3.3.1 Guiding Principles for Development of Biomethane Supply

TGI intends to apply the following guiding principles to the development of future Biomethane supply:

a) **Project Economics**: A cost of service (COS) model will be used to evaluate the attractiveness of projects, with the estimated capital and operating costs borne by Terasen and the estimated production costs of Biomethane as key inputs. Each project will be evaluated against a COS threshold that will represent the maximum cost of Biomethane delivered to the Terasen system.

b) **Gas-Processing Technology**: Terasen will use proven technology to ensure reliability and safety with technology being evaluated on the basis of cost, output gas purity and gas recovery.

c) **Working with biogas Project Proponents:** Terasen will work with project proponents to mitigate project risks.

d) **Cost Recovery**: Terasen will capture all capital and operating costs associated with the supply projects, including regulated return on capital investments in an aggregated Biomethane cost of gas calculation that will be recovered from customers participating in the Biomethane Program.

e) **Gas Quality**: Biomethane that is injected into the system must meet minimum Terasen gas quality specifications.

f) **Injection Location**: Terasen will evaluate all projects on a case-by-case basis to ensure that the injection location has sufficient local demand to utilize Biomethane.

g) **Contract Length**: Long term contracts, preferably ten years or more to allow for a stable supply and a reasonable capital depreciation period.

h) **Project Design for Mobility**: Terasen will engineer facilities in order to minimize the risk of stranded assets.

i) **Investment Arrangement**: Terasen's preferred model is to invest in upgrading equipment to retain maximum control of gas quality and safety. It will invest in sufficient equipment to ensure that quality and safety specifications are met and that there is a means of stopping Biomethane supply on short notice. In all cases, Terasen will reserve the right to refuse gas if customer safety or asset integrity is at stake.

(Exhibit B-1, pp. 74-76)

3.3.2 Maximum Biomethane Cost

Terasen proposes to apply a maximum cost as a screen for the supply of Biomethane. This will ensure it has adequate flexibility in developing new sources of supply while protecting Biomethane customers from undue rate increases. Further, Terasen notes BC Hydro's entrance into the biogas market by way of the Call for Community Biomass Energy projects. TGI states that "a given maximum rate for Biomethane helps create a better understanding for potential biogas producers of the relative economic benefits of using their biogas for upgrading to Biomethane vs. combustion to create electricity to sell to BC Hydro." (Exhibit B-1, p. 76)

TGI approach to determining the maximum Biomethane cost is addressed below.

3.3.2.1 BC Hydro's RIB Tier 2 Rate

Terasen Gas states that because there are no available external benchmarks specific to Biomethane the price of new British Columbia based electricity supply, a competing clean energy source, provides an appropriate initial reference point or proxy for Biomethane pricing until the market is better developed. By Order G-124-08 the Commission directed BC Hydro to establish the Residential Inclining Block (RIB) Tier 2 rate at BC Hydro's cost of new supply at the plant gate, grossed up for losses. Terasen states that because this rate is linked to the cost of new clean electricity supply, it is an appropriate price cap for Biomethane after adjusting for thermal efficiency and allowances for its distribution costs. Accordingly, Terasen proposes that, until such time as an alternative market-based mechanism becomes known, it will seek to develop Biomethane projects at a maximum unit cost based on the following calculation:

Table 3-5: Proposed maximum Unit Cost

BC Hydro Tier 2 Rate:[84]		8.78 ¢/kWh		
Conversion to Gigajoules	*	277.778	=	$24.389/GJ
90% Efficiency Adjustment	*	0.90	=	$21.950/GJ
Terasen Gas Rate Schedule 1 (LML) Basic Charge	-	$1.800/GJ	=	$20.150/GJ
Terasen Gas Rate Schedule 1 (LML) Delivery Charge	-	$3.145/GJ	=	$17.005/GJ
Terasen Gas Rate Schedule 1 (LML) Midstream Charge	-	$1.725/GJ	=	$15.280/GJ

Source: Exhibit B-1, p. 77

Should this formula be accepted, Terasen plans to use a maximum unit cost of $15.280 per GJ as "the default financial litmus test for the time being." In Terasen's rate structure this price would be comparable to the commodity price for conventional natural gas. Finally, Terasen proposes to adjust the maximum forecast rate to reflect the unit cost changes in the various components included in the calculation. (Exhibit B-1, pp. 76-77)

3.3.2.2 Alternatives Considered for Economic Test

In developing its proposed economic test, TGI considered and rejected five alternative methodologies as follows:

- BC Hydro Clean Energy Rate:
    - $0.13 per kWh (Clean Energy call) which, using the above conversion formula, translates into a comparative price for Biomethane of $25.83 per GJ. Terasen notes that while Biomethane costs will be streamed directly to Terasen customers, the higher clean electricity costs will be mixed into a large pool of lower-cost electricity to BC Hydro customers to form the RIB Tier 2 rate. As a result, the Clean Energy Rate would be too expensive and not comparable to the blended electricity rates actually charged to customers. Accordingly, Terasen states that "it must protect its competitive standing" and that due to its transparency, the RIB Tier 2 rate is the superior solution.
    - $150 per MWh (Bioenergy Phase 2 Call RFP) which, using the same multiplier of 277.778 kWh per GJ is equivalent to BC Hydro offering $41.667 per GJ of electricity made from raw biogas. Applying again the above conversion formula results in a competitive alternative proxy of $30.83 per GJ of Biomethane delivered to a Terasen customer. For the same reasons stated above, Terasen rejected this alternative. However, Terasen states it "may need to review this rationale as the market for Biomethane develops so as to remain competitive in sourcing biogas and Biomethane in British Columbia."
- **South East False Creek District Energy System** (SEFCDES): This option was not pursued because it might be less relevant as the SEFCDES only serves a small, high-end showcase development neighbourhood in Vancouver. Further, Terasen states that the rate structure is not truly comparable to those of large scale utilities because District Energy System rates could include more services and product offerings than the typical price for services provided by electricity or natural gas utilities.

- **Dockside Green Energy** (DGE): Terasen states that the DGE rate structure, serving one high-end neighbourhood in Victoria, encompasses a mix of a fixed amount for floor space and a variable amount for energy which is first charged to strata corporations, which then allocate the costs to individual strata unit owners. This in turn makes a direct translation between energy consumption and cost more complex. Accordingly, Terasen also rejected this option.

- **Gas Commodity Rate Cap** (a multiple of the existing natural gas commodity rate to set a fixed percentage premium): Terasen also eliminated this methodology because there is no apparent relationship between factors driving natural gas market prices and the cost of producing Biomethane. Further, Terasen notes as GHG neutral Biomethane is a fundamentally different product than conventional natural gas, therefore "imposing a pricing relationship between the two would be difficult to justify."

- **No Cap**: Terasen states that because the Biomethane service offering is fully optional for customers who may leave it at any time, setting no price cap "would be consistent with market-based economic principles of determining the price and therefore the availability of a product as being whatever the market may bear." Ultimately, however, Terasen decided that, given the lack of customer experience with this type of offering, and given that this is only the first phase of a multi-phase product roll-out, there should be a price ceiling for the product to build up both the level of customer comfort and education until the market is more mature.

(Exhibit B-1, pp. 76-80)

3.3.3 Regulatory Review of New Supply Projects and Contracts

For future biogas or Biomethane supply contracts TGI proposes a streamlined process in which it will only file the supply contract for acceptance under section 71 of the *UCA*, with no additional information. Terasen would choose not to apply for approval of expenditures pursuant to section 44.2 of the *UCA*. Terasen proposes the following criteria for this streamlined process:

1. The projected supply meets the proposed economic test with the maximum price for delivered Biomethane re-calculated from time to time based on updates to the BC Hydro RIB Tier 2 rate;

2. The supply contract is at least ten years in length;

3. Terasen has, by agreement, retained final control over the injection location;

4. Terasen is satisfied that the upgrade technology is sufficiently proven;

5. Terasen has, by agreement, reserved the right to refuse gas if customer safety or asset integrity is at stake; and

6. The partner is a municipality, regional district or other public authority, or is a private party with a track record in dealings with Terasen or that posts security to reduce the risk of stranding.

(Exhibit B-1, p. 80)

3.3.4 Post Implementation Review

Terasen states that in requesting approval for streamlining the development of future Supply and Tariff Offerings, it acknowledges a requirement for a thorough review of the Biomethane Program's success in the future. Terasen proposes that the review be conducted through a Post Implementation report and workshop, both occurring five years after the launch date of the residential Biomethane Program.

Terasen further states that this timeline should allow it adequate time to validate its research into residential and commercial markets, and to develop additional supply projects to help this industry to mature. In the meantime, Terasen proposes to report on the developments of this new program through its revenue requirement applications related to the end-to-end business model and report the Biomethane gas cost as a part of the quarterly gas cost reporting established with the Commission. (Exhibit B-1, p. 81)

3.4 Pricing Methodology

Terasen notes that the Biomethane gas which is sold to customers is expected to be more expensive than conventional natural gas for the foreseeable future. As outlined in Section 3.1.3 of this Decision, Terasen has, based upon a set of principles, developed a methodology for allocating certain costs to all TGI customers and others specifically to Biomethane Program customers who have voluntarily signed up for the offering.

For all non-bypass customers Terasen is proposing setting up non-rate base deferral accounts to capture costs incurred which are applicable to this group for the period prior to January 1, 2012 (encompassing the remainder of the 2010-2011 revenue requirements period). Following this it proposes to recover the costs from the non-bypass customer group through their amortization over the ensuing three year period. Based on projections, the impact on non-bypass customers from 2012 to 2019 varies from $0.004 to $0.006 per GJ with a levelized rate impact of $0.004 per GJ. Terasen calculates the incremental revenue requirements over this period to be $4,084,100 resulting in an annual incremental cost of 38 cents for a customer using 95 GJ per year. (Exhibit B-1, pp. 107-111)

TGI states that the Biomethane costs will be recovered from the voluntary group of Biomethane Program customers through a Biomethane Energy Recovery Charge (BERC). To capture any variance between forecasted BERC and actual costs, TGI seeks Commission approval for a further deferral account. The Company has calculated the initial BERC to be $9.904 GJ and has requested this amount be effective October 1, 2010. This will apply to 10 percent of the total gas used (the Biomethane portion) and will be adjusted annually based on deferral account balances. Customers choosing this option will do so under Rate Schedule 1B which has been applied for in this Application. (Exhibit B-1, pp. 112 -118)

4.0 KEY ISSUES AND DETERMINATIONS

4.1 Introduction

Having laid out the key attributes and a framework for the Program in Section 3.0, we will now examine the issues related to the Application. We will begin by examining the key elements of the Application in terms of its alignment with British Columbia's energy objectives and Provincial Government policy and continue with a discussion of the adequacy of supply and related demand issues. This will demonstrate that in the Panel's view there is justification for proceeding, at a minimum, with the Projects. Additionally, our examination will provide a basis upon which to discuss issues related to how to most effectively roll out the Program and protect the public interest. These include the criteria for future projects, the risk of stranded assets, principles for cost recovery, other project risks and post implementation review and reporting.

4.2 Alignment with British Columbia's Energy Objectives and Provincial Government Policy

The Panel finds that the Application is consistent with government policy as outlined in the *CEA* and elsewhere.

As noted earlier, section 2 of the *CEA,* sets out British Columbia's energy objectives. Relevant objectives include:

(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;

(g) to reduce BC greenhouse gas emissions;

> (i) by 2012 and for each subsequent calendar year to at least 6 percent less than the level of those emissions in 2007;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(j) to reduce waste by encouraging the use of waste heat, biogas and biomass.

"Greenhouse gas" is a defined term which means: "any or all of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorcarbons, sulphur hexafluoride and any other substance prescribed by regulation." (*Greenhouse Gas Reduction Targets Act* S.B.C. 2007, c. 42 s. 1) However, Terasen's evidence is that Biomethane is greenhouse gas neutral with zero carbon intensity, making it, in a pure form, greener than the electricity which is consumed in the province. (Exhibit B-10, BCUC IR 2.4.1)

The *Carbon Tax Act*, S.B.C. 2008, c. 40 (*CTA*) is also relevant. Schedule 1 to the *CTA* contains a Table which sets out the rate of tax applicable to various types of fuel, including natural gas. However, by section 1 of the *CTA*, neither methanol produced from biomass nor methane produced by waste in a landfill is considered to be a "fuel" for the purposes of the Table and is therefore arguably not subject to a carbon tax.

TGI states that it has received confirmation from the British Columbia Ministry of Finance that Biomethane itself is exempt from the carbon tax but that there is some uncertainty surrounding the tax treatment of Biomethane blended with natural gas. Terasen is seeking to obtain clarity from the Ministry on this issue. (Exhibit B-12, BCSEA IR 2.21.1)

The publication of the British Columbia government entitled "BC Bioenergy Strategy – Growing our Natural Energy Advantage" provides insight into the process, government policy and the resultant carbon footprint. Essentially, as noted above, bioenergy is energy which is derived from organic biomass; biomass being waste material which is often produced from normal daily activities and includes renewable sources such as manure, municipal waste, sewage and wood debris. When this biomass is converted to energy, it is considered to be a clean source of energy. This is because gas which would simply be released into the atmosphere naturally is used to produce energy, in place of non-renewable sources, thus reducing the greenhouse gases which would otherwise be released into the atmosphere.

The publication states: "[b]ioenergy is absolutely critical to achieving B.C.'s climate goals and economic objectives" and the government indicated that its bioenergy strategy would create new economic opportunities and "establish British Columbia as the hub of a global supply network of bioenergy resources, technologies and services."

The Application includes letters of support, including a letter dated April 5, 2010 from the BC Sustainable Energy Association which states: "[a]ppropriately carried out and regulated, the use of renewable biogas would cause net reductions in greenhouse gas emissions in BC relative to business as usual." As noted previously, the Ministry of Energy, Mines and Petroleum Resources also supports the Biomethane Program as being in alignment with Provincial policy actions and objectives.

Section 44.2 (5) of the *UCA*, requires the Commission to consider a number of matters prior to accepting an expenditure schedule filed by a public utility under section 44.2. Relevant to this application are: the applicable of British Columbia's energy objectives, Terasen's most recent long term resource plan filed under section 44.1, if any, and the interests of persons in British Columbia who receive or may receive service from the public utility.

<u>Applicable British Columbia Energy Objectives</u>

The applicable objectives were set out in detail in Sections 3.1 and 4.2 above.

The Commission Panel is of the view that the process of converting biomass to biogas to usable Biomethane uses innovative technology, as evidenced by the government's commitment to its bioenergy strategy. Biomethane is also considered to be clean and is a renewable resource. Further, the use of Biomethane in place of natural gas will reduce greenhouse gas emissions, as explained above, and the Biomethane Program entails the use of biomass and biogas.

The Commission Panel also considers the carbon tax to be another clear expression of government policy aimed at reducing carbon and the fact that Biomethane is not considered subject to the tax (albeit in a pure form) provides additional support for the Program.

The Commission Panel therefore finds that the Application is consistent with British Columbia's energy objectives and Provincial Government energy policy.

TGI's Most Recent Long Term Resource Plan

Terasen filed a long term resource plan under section 44.1 on June 27, 2008. The long term resource plan included five year capital plans and statements of facilities expansion, although no specific approval was requested. The only issues of any contention were carved off and made the subject of a separate proceeding, being Terasen's Energy Efficiency and Conservation Application. The long term resource plan was accepted in its modified form by Commission Order G-194-08 dated December 15, 2008.

The Commission Panel sees nothing in Terasen's long term resource plan which is inconsistent with the Biomethane Program.

The Interests of Persons in British Columbia who
Receive or May Receive Service from Terasen Gas

The Commission Panel considers that allowing customers to opt to select the more expensive Biomethane product is in the interests of Terasen's customers at this time, as it will provide maximum customer choice. In the future, it may be unnecessary to allow for this choice, as the carbon tax increases and prices of natural gas and Biomethane adjust in accordance with market forces. A portion of the expenditure will be recovered from all non-bypass customers and, considering the relatively small cost of making the Program available, the Commission believes that it is in the interest of Terasen customers whether or not they choose to participate.

4.3 Biogas Supply

To evaluate the merits of the Application, the Commission must determine if there is enough evidence in this proceeding to forecast that the potential Biomethane supply in TGI's service area can support the planned offering. Within the Application, Terasen performs an evaluation and concludes that the potential Biomethane supply is sufficient. (Exhibit B-1, p. 66)

In order to estimate the future potential of Biomethane, TGI undertook a four step process that included: i) quantifying the total amount of bioenergy in BC; ii) identifying and excluding bioenergy resources not suitable for Biomethane; iii) estimating the range of supply, and iv) developing a short term supply estimate. This process involved collecting data from sources who have studied BC's bioenergy, making reasonable estimates of future events, and engaging potential partners who have an interest in Biomethane production. (Exhibit B-1, pp. 62-65)

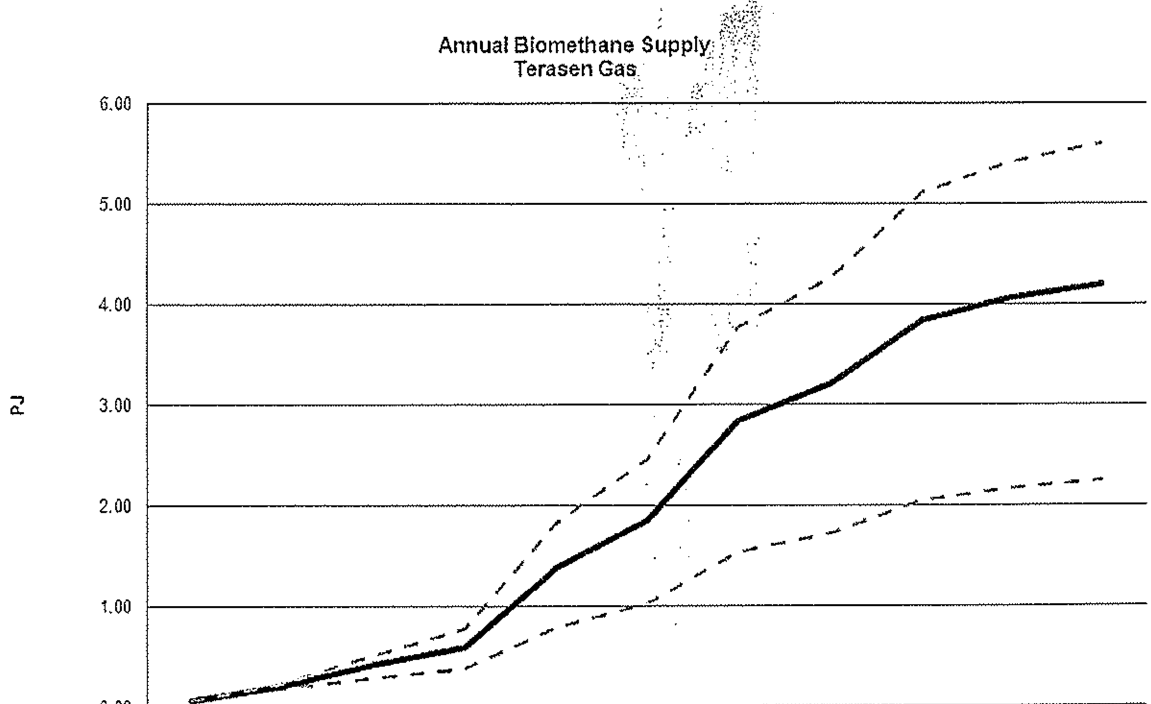
Supported by this preliminary estimation, TGI believes there is sufficient raw biogas to produce enough Biomethane to support its planned offering and estimates Biomethane supply in 10 years could be in the range of 2.24 to 5.6 Petajoules (PJ).[2] Terasen also noted that there is strong interest from various potential partners to work with it to develop Biomethane projects within its service territory. (Exhibit B-1, p. 66, as amended by Exhibit B-1-1)

However, Terasen notes that the sources of the energy and estimated supply of Biomethane are not well established. It is Terasen Gas' position that the first four years of the estimate are more accurate than the long-term forecast, but both long-term and short-term estimates are subject to some uncertainty. (Exhibit B-1, p. 65)

A graphic demonstration of Terasen's estimated availability of Biomethane until 2020 has been included below:

[2] One Petajoule is 10^6 Gigajoules and Terasen's total forecast energy consumption for 2011 was 161.8 PJ in the 2010-2011 Revenue Requirements Application made to the Commission on June 15, 2009.

Figure 4-1: Terasen Gas Forecast for Annual Biomethane Supply (PJ)



	2010**	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Low	0.05	0.18	0.29	0.38	0.79	1.03	1.54	1.72	2.05	2.17	2.24
Expected	0.05	0.21	0.41	0.59	1.38	1.85	2.84	3.20	3.84	4.07	4.20
High	0.05	0.23	0.50	0.76	1.82	2.45	3.78	4.26	5.12	5.42	5.60

Source: Exhibit B-1, p. 65 as amended by Exhibit B-1-1

TGI's projection of Biomethane supply indicates that initial supplies will be much lower than the potential supplies reached in 2020. It forecasts Biomethane supplies in 2010 to be 0.05 PJ and to be in the range of 0.18-0.23 PJ in 2011. (Exhibit B-1, p. 65 as amended by Exhibit B-1-1) Given that Biomethane supplies are not yet well established (Exhibit B-1, p. 65), the Company has proposed risk-management techniques to address potential Biomethane supply shortfalls. Terasen suggests that these techniques, which include limiting program enrollment and reserving the right to purchase carbon offset credits or remove customers from the program provide the Company with an additional safety net if needed. (Terasen Final Submission, p. 44)

No Intervener raised concerns regarding matters of Terasen's Biomethane supply.

Commission Determination

The Commission Panel believes that Terasen has reasonably identified potential sources of biogas in its service area and evaluated the likelihood of Biomethane production. However, this is a new type of venture and there is little independent evidence to corroborate these estimates. The Commission Panel is satisfied that Terasen understands this difficulty and related impacts, and has made reasonable attempts to formulate an estimate given these constraints. **The Commission Panel accepts TGI's estimate of its potential Biomethane supply and finds this supply to be sufficient to justify moving forward with the Biomethane Program but the Panel also acknowledges the limited data available to support this estimate.**

As noted, the Commission Panel accepts that there is a risk that the Biomethane supply estimates may be inaccurate. The Commission Panel further notes that TGI has attempted to mitigate this risk by proposing policies that allow it to purchase carbon offset credits or limit service in certain circumstances. **The Commission Panel finds that TGI has proposed reasonable techniques to address the risk of Biomethane shortfalls if short-term supply estimates are overstated. Further, the Commission Panel approves TGI's proposal to purchase carbon offsets and to recover costs through the Biomethane Variance Account in the event of under-supply of Biomethane, at a per gigajoule unit price not to exceed the difference between the Biomethane Energy Recovery Charge and the Commodity Cost Recovery Charge in effect at that time.**

4.4 Product Demand

A fundamental consideration is determining whether there is sufficient demand from the BC consumer to justify the implementation of a comprehensive Biomethane gas offering program within the province. Terasen, as a means of providing background in its Application, provides an overview of the types of green business models or programs deployed in North America and their participation rates. (Exhibit B-1, pp. 28-29) In addition, Terasen commissioned TNS Canadian Facts (TNS) to conduct primary research as a means of evaluating and validating potential BC residential and commercial markets for a biogas program as well as the market drivers and factors affecting different price points. (Exhibit B-1, p. 35)

In its review of voluntary renewable energy market programs in North America, Terasen notes that there are three primary types of programs:

- Contribution programs – those designed to allow customers to contribute to a utility managed fund for renewable energy project development.
- Energy-based programs – those allowing customers for a premium to purchase a certain amount of energy from sources which are renewable.
- Carbon offset programs – those which provide the customer the option of offsetting their GHG emissions through the purchase of carbon offsets.

Of these, Terasen notes that energy-based programs had the highest level of success. Further, the Company reports that according to National Renewable Energy Laboratory (NREL) the top ten green programs in the US in 2008 had participation rates ranging from 5 percent to 21 percent and all ten were some type of energy-based scheme. Overall, the participation rate for all programs reported on had a mean of 2.2 percent and a median of 1.2 percent, numbers which have increased steadily over the previous six years. (Exhibit B-1, pp. 28-30) Terasen reports that if the average were relied upon, the uptake in this jurisdiction would result in over 16,000 signups for the Biomethane Program. This exceeds anticipated production at the two current supply projects in the Application. (Exhibit B-1, p. 46)

Terasen commissioned a survey of residential and commercial customers. Key findings of the survey as reported are as follows:

1. Both residential and commercial customers strongly support Terasen's investment in and the offering of biogas programs (67 percent support investing in biogas projects and 65 percent support offering programs).
2. Both customer markets also show preference for an energy-based program. When presented with a choice between biogas and carbon offsets, customers favoured the former by a three to one margin. Further, 56 percent of residential and 47 percent of commercial customers indicated they would sign up for a biogas program as opposed to 24 percent of

residential and 35 percent of commercial who would do so with a carbon offset based program.

3. When given a choice as to whether customers would prefer a program that was paid for by customers who signed up for a biogas offering and paid a premium as opposed to all customers bearing the cost 47 percent of residential and 60 percent of commercial customers preferred a universal price increase (to all customers) while 26 percent supported a premium price increase. However, a large number (27 percent) did not state a preference or did not know how to answer the question. When questioned further about the level of increased costs customers would be willing to pay if all customers had to pay (amounts between 0.5 and 3 percent were explored), there was a strong support for a modest percentage increase in cost (between 0.5 and 1 percent). This support lessened as the cost premium approached 3 percent.

4. With respect to price premiums and blends with a voluntary program, there was a strong preference for a 10 percent price premium on the commodity and for a 10 percent blend of biogas and corresponding GHG reductions (46 percent for both residential and commercial). The preference dropped significantly for higher prices and blends of biogas and GHG reductions.

5. Assuming the program was offered on a voluntary basis, 16 percent of residential and 10 percent of commercial customers indicated a disposition to enroll. These numbers drop as the price level is raised. Terasen reports that this equates to an estimated 120,000 residential customers and 9,200 commercial customers.

On the basis of this research Terasen has concluded that a renewable energy program where customers enroll to have a portion of their natural gas come from biogas will be most effective. Terasen further concludes that the number of customers who would support a universal cost increase if it were moderate, is supportive of its proposed hybrid model where some costs associated with the Program are borne by all customers. Finally, it has concluded that the research supports rolling out the Program first to residential customers due to their higher participation potential and their preference for an initial offering of a 10 percent cost increase for a 10 percent blend to maximize household involvement. (Exhibit B-1, pp. 35-47)

In response to BCOAPO IR 1.4.3, Terasen indicated that it undertook to reflect some of the characteristics of the top ten green programs in its proposal. Included among these are the following: the choice of a renewable energy program, the consideration of marketing strategies such as those identified in Chartwell's "Helping Customers Live a Sustainable Lifestyle 2007"

(Exhibit B-1, Appendix C-2), and the use of a lower price option in the introductory phase of the program.

None of the Interveners expressed concern with respect to Terasen's estimate of customer demand and how this was integrated into Program development. However, the BCOAPO did express some concern with respect to the use of the mean rather than the median as related to the level of "take up" rates in the secondary research. In spite of these concerns, it stated it did not "believe that TGI's estimated total demands for green offerings are a cause for concern **in this proceeding.**" (BCOAPO Final Submission, p. 3, emphasis in original)

Commission Determination

The body of research presented by Terasen demonstrates that there is a willingness among customers to actively support what has been described as "green pricing" programs. The information provided by NREL indicates that there is significant variance among the US jurisdictions reviewed with respect to the level of participation. Ignoring for a moment the results and attributes of the ten most successful programs, the fact that the mean participation rate for all programs was 2.2 percent, which would result in an uptake rate of 16,000 households in BC, provides some comfort notwithstanding the concerns raised by BCOAPO that the median of 1.2 percent was a more appropriate measure. By contrast, the TNS survey indicates there may be a potential participation rate as high as 120,000 households if customer actual participation rates match customer intentions measures.

The Commission Panel notes that the TNS survey undertaken by Terasen was with BC residents only and is more representative and better reflects the customer views and intentions as well as the unique market conditions within the province of British Columbia. Accordingly, we put more weight on this survey in spite of the fact that it measures intentions rather than actual results as was the case with the NREL Report. However, in doing so the Panel acknowledges there is a potential for a relatively high participation rate (perhaps as many as 120,000 households) but is not persuaded that the case for this has been adequately made. In our view, the most appropriate way to determine the actual market potential as differentiated from customer intentions is to test it within the BC market.

Terasen, in the view of the Panel has chosen a model which has been designed to reflect much of what has been learned from successful programs in other jurisdictions as well as from the primary research conducted within BC. Firstly, the choice of an energy-based program is very much in keeping with the success stories from other jurisdictions. Moreover, it is an appropriate response to what was learned through research in the BC market where both residential and commercial customers indicated a strong preference for this type of model. We also consider the choice of a 10 percent premium for a 10 percent blend of biogas to be a good choice given the fact that the TNS survey indicates a strong preference for these percentage levels.

The Commission Panel finds that the research presented by Terasen supports the position that there is likely to be sufficient demand to justify moving forward with a Biomethane Program.

4.5 Commission Determination on the Projects

As noted in the above, the Commission Panel is satisfied there is sufficient demand for and supply of Biomethane to move forward with the Projects. Further, the Panel is satisfied the Program is in alignment with British Columbia's energy objectives and government policy. **Accordingly, we approve the Purchase Agreements with the CSRD and Catalyst, and expenditures related to the facilities for both of these Projects.**

However, the Panel remains concerned that the model proposed by Terasen Gas has yet to be tested in the British Columbia marketplace. In our view it would be prudent for TGI to gain knowledge and experience by a thorough testing of the Program before any firm determination can be made as to the full market potential. The two Projects will provide a reference case which will serve as a basis for future projects. **Therefore, we have determined the scope of the Biomethane Program should be limited until such time as actual results can be analyzed and more definitive conclusions drawn.** This will be discussed further in Section 4.6, Criteria for Future Projects.

4.6 Terasen's Role in Biogas Upgrading Process

TGI takes the position that its ownership and operation of the upgrading facilities will promote the efficient development of Biomethane supply projects and ensure that the Biomethane, which is to be injected into the distribution system, will arrive "safely and economically" with dependable flow. (Exhibit B-1, p. 6) As discussed earlier, the upgrading process purifies raw biogas to remove contaminants, producing Biomethane, which is directly substitutable for natural gas.

As discussed previously, Terasen Gas proposes two business supply models. In one, CSRD, Terasen will purchase raw biogas from a supplier and upgrade that gas to Biomethane. This model will therefore entail Terasen's investment in the facilities required to upgrade the biogas to Biomethane. This is above and beyond its investment in the facilities necessary to measure the flow of gas, connect to the TGI distribution system and test the gas to ensure its compatibility with natural gas, which is a requirement under both business models.

Terasen notes that its proposed investment in the upgrading facilities is minor in comparison with the significant capital investment involved in the development and collection of raw biogas, a field which it does not intend to enter, as this is currently outside its area of expertise. Nonetheless, its capital investment is acknowledged to be "material." (Exhibit B-1, pp. 6, 76)

Terasen states that the upgrading of biogas to Biomethane "is purely a gas processing and gas management step" falling within its core expertise and that TGI "is best positioned in most cases to ensure that the biogas is upgraded in a manner that will best ensure a consistent and reliable supply of Biomethane.... ." (Exhibit B-1, p. 71)

TGI describes the advantages of its ownership of the upgrading facilities as follows:

- Terasen is able to best ensure the safe, reliable and economic delivery of Biomethane to the distribution system;
- Terasen's retention of control over the upgrading process allows it to optimize operations and balance final gas quality with total volume of Biomethane; and

- Terasen's point of control being further upstream of the measuring and monitoring point gives Terasen greater control of gas quality and customer and equipment safety.

(Exhibit B-1, p. 71)

Terasen summarizes its position: "Terasen Gas must own and operate equipment to upgrade raw biogas to Biomethane in order to ensure safe and reliable operation of Biomethane supply projects." However, Terasen Gas does concede that when appropriate project partners can be found, there will be an opportunity for the development of "an independent Biomethane upgrading industry in British Columbia." (Exhibit B-1, p. 72)

Terasen advises that in the natural gas industry, raw gas producers may own and operate the upgrading facilities, or the raw gas may be upgraded in third party facilities. (Exhibit B-1, p. 73)

Terasen also notes that at the time it filed its Application there were "no operating biogas upgrading plants in the province and therefore no experienced operators." (Exhibit B-3, BCUC IR 1.2.2)

Terasen Gas suggests that, as its ownership of the upgrading equipment as utility assets best ensures the reliability of supply, this should be the preferred ownership model, absent other commercial reasons favouring third party ownership. Terasen submits that this supports a flexible approach to the issue. (Terasen Final Submission, p. 29) Terasen further suggests that "commercial realities" will favour TGI's ownership and operation of the upgrading facilities as its involvement as an experienced, reputable and reliable partner will assist developers in obtaining financing. It also suggests that less financing will be needed in total if it owns the upgrading equipment instead of the developer. It further states that "[d]evelopers have indicated that a partner with experience in gas processing and gas technology is attractive." (Exhibit B-2, BCUC IR 1.2.2; Terasen Final Submission, p. 31)

Terasen also submits that, to the extent that its involvement in the upgrading operation might discourage other market participants, such a line of enquiry is misplaced and that "[p]rotecting potential third party suppliers (if and when they exist) from competition...to encourage new market participants cannot be the end objective of public utility regulation as defined by the [Utilities Commission] Act." It submits that the Commission only has jurisdiction over the competitive landscape for ownership of upgrading facilities to the extent that such ownership is ultimately related to the quality, reliability and cost-effectiveness of Biomethane service." Terasen adds that "logic would suggest that the longer-term effect of insulating third parties that might be interested in owning upgrading facilities from competition with an efficient producer like TGI will be inefficiencies that result in higher overall costs of supply to customers." (Terasen Final Submission, p. 31)

Terasen's evidence is that the only constraint it is placing on potential third party involvement in the upgrading process is that they are "able to demonstrate they are capable of providing a reliable and safe source of Biomethane." (Exhibit B-3, BCUC IR 1.26.1)

To the BCOAPO, "the nub of the issue is whether to permit the regulated monopoly distribution utility to venture into a commodity supply venture, and how to reconcile this intrusion into the unregulated, competitive supply market with the need to develop more environmentally benign ways of sourcing household energy." The BCOAPO offers only "strings-attached" support for the Application, stressing that in its view, "biogas marketing and project costs are, for the most part, best undertaken by non-utility entities" and that this "should not be taken as a template or precedent for the utility to venture further into the gas commodity refining and supply line of business." (BCOAPO Final Submission, p. 3)

Terasen maintains the view that its venture into the upgrading industry should be done through Terasen Gas itself in its current structure as opposed to through a non-regulated business or through a separate, regulated entity. It's position is that all upgrading activities are subject to regulation by the Commission, given the definition of "public utility" in the *UCA*, and its application to a "person...who owns or operates...equipment or facilities...for... the production...of natural gas...or any other agent [i.e. Biomethane] for the production of ... heat ... to or for the public or a corporation for compensation..." Terasen states that the definition of public utility covers both the upgrading of biogas to Biomethane and the notional sale of the Biomethane to customers and that any entity that sells upgraded Biomethane either to the public or to Terasen will be subject to the Commission's regulatory oversight.

However, Terasen suggests that regulation of this business need not be active, but "passive" as the pricing issue can be addressed in the review of the purchase agreements. (Exhibit B-3, BCUC IR 1.1.1)

Terasen states that the "BCOAPO has not articulated how or why TGI's supply model will impair fair competition, prevent a competitive marketplace, or negatively impact ratepayers" and suggests that its evidence in respect of its (or a reliable partner's) need to own and operate biogas upgrading equipment was not challenged. It further suggests that the BCOAPO did not address its other areas of evidence relating to the development of a competitive marketplace. (Terasen Reply, p. 4)

Commission Determination

Assuming, without necessarily deciding that upgrading processes are subject to regulation by the Commission, the Commission Panel remains concerned about Terasen's entry into a new area of business. The Commission Panel is not convinced that Terasen must be involved in the upgrading process to ensure the quality of product, reliability of delivery, and safety of the operation. The Commission Panel is of the view that Terasen's testing and control of the product in its interconnection facilities, prior to its inclusion in the distribution system, which will happen under either proposed business model, will provide that measure of protection. However, the Commission Panel is prepared to allow the CSRD Project to proceed considering grants have been obtained to reduce the cost (and risk) of the project.

The Commission Panel makes no finding on the acceptability of Terasen's involvement in performing the upgrading at this time, particularly as there may be an industry developing which might result in a competitive business environment for future upgrading projects. As this is a new business for Terasen, the Commission Panel rejects Terasen's submission that it is or will necessarily be an "efficient producer" and that its involvement in the upgrading process necessarily promotes "cost effectiveness". In addition, the Commission Panel notes that the upgrading of biogas does not have the significant upfront capital investment and potential economies of scale typical of a natural monopoly. Upgrading of biogas may therefore evolve to an industry made up of a number of separate, small upgrading businesses. The use of a separate entity, owned by Terasen, will maintain the advantages Terasen's cites in terms of its reputation, experience and expertise. **Accordingly, the Commission Panel directs that Terasen's costs of the upgrading project be segregated so they may be compared with costs of other potential upgrading operations by other industry participants in the future. The Commission Panel further directs that the upgrading business be kept sufficiently distinct so as to be severable, should the Commission determine that this business ought to be conducted through a separate entity in the future.**

4.7 Criteria for Future Projects

As outlined in Section 3.3 of this Decision, TGI has proposed that the process for regulatory review of future new supply projects and contracts be streamlined. Within the Application it has sought an order to allow future supply contracts that meet the criteria described within Section 8.4 of the Application to also meet the filing requirements in sections 71(1) (a) and 71(1) (b) of the *UCA.* (Exhibit B-1, p. 133) Accordingly, the Company proposes to file supply contracts only under section 70 [sic] without additional supporting information. (Exhibit B-1, p. 80)

In its Final Submission, Terasen states that the Commission can accept an energy supply contract under section 71 or it can require additional evidence in support of the public interest. Terasen argues that many of the public interest considerations will be the same, while acknowledging there will be differences which will exist among future supply contracts with respect to terms of the agreements including price. Accordingly, TGI submits that the potential for redundancy in the Commission's review of what are relatively small supply projects makes it desirable for an efficient public interest review process and the criteria (outlined in Section 3.3 of this Decision) provide an appropriate reference point. (Terasen Final Submission, p. 34)

Both the CEC and BCSEA generally support the proposal put forward by Terasen with respect to establishing criteria for acceptance under section 71. BCSEA notes that it provides a balance between efficiency and regulatory oversight. (BCSEA Final Submission, p. 7) The CEC submits that because of the small size of the projects being considered, it would be inappropriate to burden this new initiative with undue regulatory process. However, the CEC submits that the Commission should consider two additional criteria; continued prospects for customers buying the service and continued backup plans for mitigation of risk for the magnitude of supply under contract. (CEC Final Submission, p. 3) BCOAPO provided no specific submissions with respect to the criteria issue.

Terasen states that concerns underlying the CEC's recommendation for the additional criteria have been adequately addressed in the proposal. (Terasen Reply, p. 2)

The Commission Panel acknowledges the need to promote regulatory efficiency where appropriate and in the public interest. However, in doing so, it underlines the importance of establishing criteria that are sufficiently precise and comprehensive to ensure the public interest continues to be met in the future. The Panel believes there are a number of issues arising from the criteria which have been proposed by Terasen. Firstly, there is concern as to whether the RIB Tier 2 rate proposed by Terasen as a price ceiling is appropriate. Secondly, the Panel has concerns with respect to scope of the criteria being proposed and believes that consideration of further criteria should be undertaken in reaching a determination on this.

As outlined previously in Section 3.3.2.1 of this Decision, TGI states that the justification to use RIB Tier 2 pricing as a proxy for Biomethane pricing is based upon two factors:

- the lack of external benchmarks specific to Biomethane; and
- the fact that RIB Tier 2 pricing (currently $15.28) reflects the price of new British Columbia based electrical supply which is viewed as a competing clean energy source.

On this issue the CEC, while stating it is comfortable with the proposed $15 ceiling, submits the RIB Tier 2 rate may not be the most appropriate way to regulate Biomethane as BC Hydro's rates may vary for numerous unrelated reasons. (CEC Final Submission, p. 3) BCSEA submits that it agrees with TGI's reliance on the RIB Tier 2 rate as a benchmark for establishing an appropriate cost at least until an alternative market- based mechanism is found. (BCSEA Final Submission, p. 5)

No other Intervener took a position on the price ceiling.

Terasen Gas points out in its Reply that there are currently no external pricing benchmarks for Biomethane and the RIB Tier 2 rate is only an initial reference point and it will propose a price ceiling change in the event it becomes necessary in the future. (Terasen Reply, p. 2)

With respect to the scope of criteria, the Panel notes again that this is a completely new business undertaking for Terasen. While the research conducted indicates there is good potential, this has yet to be proven in the BC marketplace and, in spite of expectations, it could result in failure. The potential impact of this is raised by BCOAPO in its Final Submission where it notes its main concern relates to the impact of the cost of stranded assets on non-participants if the commercial venture is unsuccessful. BCOAPO acknowledges that the small cost, the review process and the ability to remove and resell the installation if required, serve to mitigate its concern. (BCOAPO Final Submission, p. 3)

Commission Determination

The Commission Panel accepts that there is a need for streamlining of the approval process as it is likely that many of the projects which will be proposed in the future will be small in size and subjecting them to rigorous scrutiny in each case would not be in the public interest. **Accordingly, we have determined that future energy supply contracts for the purchase of biogas or Biomethane that meet the criteria listed in Section 3.3.3 of these Reasons with the following additional criteria will meet the filing requirements in sections 71(1)(a) and 71(1)(b) of the *Act*:**

- **The total production of Biomethane for all projects undertaken under what has been approved in this Decision does not exceed an annual purchase in each year of 250,000 GJ.**
- **The maximum price for delivered Biomethane on the system is set at $15.28 per GJ.**

The Panel is encouraged by the initiative Terasen Gas has taken with this Biomethane Program and, subject to certain conditions raised within this Decision, is supportive of moving forward with additional projects in the future. However, the Biomethane Program is a new initiative and has not been tested in the marketplace. If the Panel were to approve future projects with no limitations as proposed by Terasen in the Application, it could be placing the ratepayer at risk for what in total could be a substantial amount. We do not believe this would be in the public interest. However, we are not convinced that the risk is so great that all future initiatives should be held back pending full testing of the model as suggested by the comments of BCOAPO. Therefore, we have provided in our determination that TGI can purchase a total of 250,000 GJ annually which will allow some latitude for TGI to proceed with some additional projects before returning to the Commission with the results from what has been undertaken and recommendations for the future. Nevertheless, the Panel would like to be clear that in spite of this, we view these initial programs as a test phase only. The results from these projects will very much determine whether the Program will continue and whether the model as proposed is suitable. We acknowledge the recommendations of the CEC with respect to additional criteria but given the limitations we have set, it is premature to add these criteria at this time. Further, even with these criteria as Terasen has acknowledged, the Commission retains the right to depart from them and require further process. (Exhibit B-3, BCUC 1.24.3)

The Commission Panel notes the comments of CEC with respect to tying the pricing ceiling for future projects to the RIB Tier 2 rate as proposed by Terasen and has similar concerns with respect to the potential for future price changes. However, the Panel is satisfied that setting the rate ceiling at $15.28 per GJ which corresponds to the current RIB Tier 2 rate is reasonable as it provides Terasen with sufficient discretion to operate with some flexibility with the initial projects.

4.8 Risk of Stranded Assets

A stranded asset is an asset that is worth less on the market than it is on a balance sheet due to the fact that it has become obsolete in advance of complete depreciation. Stranded costs related to stranded assets are inevitable in any industry where the regulatory environment changes dramatically, and partial or full compensation for stranded costs is usually considered fair play for monopoly services suddenly thrust into a competitive market place. Today, the debate continues regarding the extent to which the regulatory compact entitles utilities to recover the cost of stranded assets in future rates. Depending on circumstances, utilities have been allowed to recover the entire investment or a partial investment from their regular customers over a certain amortization period. There may even be situations where no recovery would be permitted. This larger question cannot be answered in this proceeding but, nevertheless, the following should be considered in this context of uncertainty regarding the ultimate responsibility over stranded assets.

This Section addresses the risk of the Projects in the event those ventures are not commercially successful. Related to the risk of failure to supply is the potential for permanent termination of the contract by project partners that would leave Terasen's installed facilities idle. This is a particular concern in the case of the CSRD Project where Terasen Gas is investing in the upgrading facilities.

TGI submits that the risk of stranded assets is modest to start with and that Terasen has taken appropriate steps to mitigate that risk contractually:

- The overall investment required by Terasen is low, being $1.8 Million for CSRD and $0.6 Million for Catalyst;
- There is little risk of stranding associated with lack of customer demand, as the Biomethane generated by the two projects would be consumed based on the conservative measure of industry average demand;
- The 15-year and 10-year terms for the CSRD and Catalyst Projects respectively provide longer term supply of biogas and a reasonable period over which to recover equipment costs;

- Under the contracts, Terasen has the right to enter the site and physically recover its facilities after a specified period of non-performance. The majority of facilities used for the project could be recovered and used for other projects. In addition, the CSRD contract provides Terasen with a termination payment in excess of the estimated value of the stranded assests and moving costs whereas the Catalyst contract provides Terasen with appropriate security against stranding; and
- Advancements in upgrading technology will have little impact on the success of the CSRD project, as the current equipment recovers as much as 95 percent of the methane in raw biogas. As a result, any technological improvements over time will result in only minor efficiency improvements and would therefore not make the current technology obsolete.

(Terasen Final Submission, pp. 24-25, 28)

BCOAPO submits that its main concern (apart from whether this is appropriate utility activity at all) is "the risk of stranded costs being visited upon non-participants if the venture is not successful commercially." However, BCOAPO acknolwedges that in this case the relatively small cost, the post-implementation review, and the configuration of the installation to facilitate removal and resale, all mitigate that concern. Finally, BCOAPO submits that Biomethane is a technology which should have an opportunity to incubate under the aegis of the utility, so long as financial risks to non-participants are contained, and that the proposed projects may be a useful and necessary "kickstart" for future green initiatives by other parties. (BCOAPO Final Submission, pp. 2-3)

The CEC submits that the investments proposed by Terasen are modest, the risks relative to those investments are well identified and Terasen has plans for substantial risk mitigation should they be realized. Accordingly, the CEC agrees with Terasen's summary of its evidence. (CEC Final Submission, p. 2)

Commission Determination

The Commission Panel finds that the total capital investment required by TGI for the Projects is relatively low; especially after allowing for the funding received from the Innovative Clean Energy fund and from the BC Bioenergy Network. The Commission Panel also notes the supporting

Intervener submissions on this matter and finds that Terasen has taken reasonable steps to mitigate the ultimate risk of stranded assets in terms of the specific structure of contracts it has negotiated. Finally, the Commission Panel finds that there is little risk of stranding due to lack of customer demand as the estimates used for projections are on the conservative side.

With regard to future projects, the Commission Panel finds that the Guiding Principles for Development of Biomethane Supply, the proposed contract language as well as the price ceiling, a predetermined production quantity limit and the shorter time period to be allowed for the test period will serve to mitigate concern over the risk of stranded assets. This should be true even in the cases of future projects that will not receive special funding.

4.9 Principles for Cost Recovery

As illustrated in the Biomethane Service Offering Model diagram in Section 3.0, Terasen proposes that customers opting for the Biomethane Offering should pay the full costs of the Biomethane gas supply while all Terasen Gas customers will share the costs related to the interconnection and monitoring equipment as well as the cost of IT upgrades, program management and customer education. This Section outlines the proposal in more detail to address the question: Should any costs be shared by all Terasen customers at all?

4.9.1 Rate Setting

Terasen seeks approval for its proposed rate, tariff provisions, cost allocation methodology, and accounting treatment pursuant to sections 44.2, and 59 to 61 of the UCA. These are listed in Appendix E.

4.9.2 General Cost Recovery Principles

TGI proposes that customers opting into the Offering and committing to purchase Biomethane should pay the full costs to supply pipeline quality Biomethane gas. Where Terasen will acquire raw biogas for upgrading, the acquisition costs of the raw biogas, and the costs of owning and operating the upgrading equipment will be fully recovered via the Biomethane rate. Similarly, for those projects where Terasen will acquire pipeline-ready Biomethane, these costs will be fully recovered via the Biomethane rate. Terasen states that incremental Customer Works LP (CWLP) charges related to processing customer enrolments in the Biomethane Program and ongoing O&M such as customer drops, moves and changes will be fully recovered from only the Biomethane Program customers via the Biomethane rate. (Exhibit B-1, p. 17)

However, Terasen Gas states that some costs are being incurred in order to give all customers the choice of participating in the Biomethane Program, and that all customers obtain environmental benefits from Terasen offering Biomethane as an option. Terasen further states that costs incurred to provide this choice and deliver environmental benefits should be allocated to all customers of the utility because this is consistent with the implementation of other programs, such as the Customer Choice Program. (Exhibit B-1, pp. 107-108)

All operating and maintenace and capital costs included in the determination of the rate impacts, including the allocation of costs between all customers and those choosing to participate in the Biomethane Program, are shown in the following two tables.

Table 4-1

Terasen Gas Inc. – Biogas O&M Details

Line	Particulars	2010	2011	2012 [1]
		($ thousands)		
1	O&M Costs - All Customers			
2	Labour Costs - One FTE	25.0	100.0	100.0
3				
4	Computer Costs - Additional Reporting	-	-	10.0
5				
6	Customer Education	160.0	240.0	300.0
7	Internal Reporting Changes	0.8	2.4	-
8	Inbound Calls			6.4
9	Fees & Administrations Costs	160.8	242.4	306.4
10				
11	Inbound Calls	7.2	28.7	-
12	Rate Changes	-	4.0	-
13	Application Support	165.6	-	-
14	Contractor Costs	172.8	32.7	-
15				
16	**Total O&M Costs - All Customers**	358.6	375.1	416.4
17				
18	O&M Costs - Catalyst Project (3 months in 2010)			
19	Electrical Power	1.0	2.0	2.0
20	Equipment Maintenance	1.0	2.0	2.0
21	Other	14.5	29.0	29.6
22	Total Catalyst Materials & Supplies	16.5	33.0	33.7
23				
24	O&M Costs - Salmon Arm Project (6 months in 2010)			
25	Electrical Power	11.5	46.0	46.9
26	Equipment Maintenance	1.3	5.0	5.1
27	Other	1.3	5.0	5.1
28	Total Salmon Arm Materials & Supplies	14.0	56.0	57.1
29				
30	Total Materials & Supplies	30.5	89.0	90.8
31				
32	O&M Costs - Biogas Customers (Customer related)	14.6	82.4	56.9
33				
34	**Total O&M Costs - Biogas Customers**	45.1	171.4	147.7
35				
36	[1] Years subsequent to 2012 are adjusted by inflation			

Source: Exhibit B-1, Appendix J-1, p. 1

Table 4-2

Terasen Gas Inc. – Biogas Capital Details

Line	Particulars	Catalyst ($ thousands)	Salmon Arm ($ thousands)	Total ($ thousands)
1	**Capital Costs - All Customers**			
2	Meters	77.3	395.5	472.8
3	Distribution Measurement & Regulating	282.5	242.0	524.5
4	Distribution Main Extension	227.9	45.1	273.0
5		587.7	682.6	1,270.3
6				
7	**Capital Costs - Biogas Customers**			
8	Upgrader	-	1,621.8	1,621.8
9				
10	**Total Capital Costs**	587.7	2,304.4	2,892.1
11				
12	CIAC (ICE and BCBN funding)	-	(515.6)	(515.6)
13				
14	**Capital Costs net of CIAC**	587.7	1,788.8	2,376.5
15				
16	Note: All spending occurs in 2010 except $96.1 thousand of the upgrader spent in 2011			

Source: Exhibit B-1, Appendix J-1, p. 2

4.9.3 Determination of Costs Related to System Changes

TGI commissioned an IT consulting firm to assess the required business system changes and estimate the costs required to implement the new Offering, including customer enrolment, program management, nominations, customer billing and rate setting. Terasen states that the system impact analysis has taken into consideration the existing initiative to replace the current customer billing system and move customer care services in-house. Terasen believes it has developed a cost-effective and workable solution along with supporting processes and systems to implement a Biomethane Program in British Columbia. (Exhibit B-1, p. 109)

4.9.4 Costs to be Allocated to all Customers

Costs that will be allocated to all Terasen Gas distribution customers will include:

- Cost of service related to gas analyzing equipment, meters, transmission or distribution pipeline extensions constructed to receive the injection of Biomethane;

- Capital costs for application development and configuration of the current customer billing system and modifications to supporting processes to support accepting on-line enrolment requests, configure the new Biomethane tariff and provide additional reporting;

- On-going operating costs related to additional customer inquiry calls, quarterly updates to the tariff rate, customer education costs, including costs associated with marketing the Program, and a new full time position of biogas Program Manager.

Terasen proposes the creation of a non-rate base deferral account to capture costs applicable to all customers incurred prior to January 1, 2012. It further proposes to recover these costs from all non-bypass customers by amortizing them through delivery rates commencing January 1, 2012 over a three year period. The forecast levelized rate impact for these customers is $0.004 per GJ. By way of example, Terasen states that for a residential customer using 95 GJ per year, the annual incremental cost is 38 cents. (Exhibit B-1, pp. 110-111)

4.9.5 Costs to be Allocated to Biomethane Program Customers

Costs to be allocated to Biomethane Program customers include the cost of purchasing Biomethane and raw biogas, including upgrading costs, as well as the ongoing administrative O&M costs directly related to Biomethane customers such as customer enrollment, removal of customers from the program and billing adjustments.

Terasen proposes to recover these costs through a Biomethane Energy Recovery Charge. As this rate will be based on forecast costs, Terasen seeks Commission approval of a deferral account, the Biomethane Variance Account (BVA), to capture the difference between actual costs and revenues collected through the BERC rate. Terasen has calculated the BERC rate as $ 9.904/GJ and seeks approval of the Biomethane Energy Recovery Charge at this amount effective October 1, 2010. (Exhibit B-1, p. 117)

By electing to participate in the first phase of the Biomethane Program offering, residential customers will pay a gas commodity price based on a 10 percent Biomethane and 90 percent natural gas blend. Terasen submits its proposal results in a minimal rate impact for all non-bypass customers, and a Premium Service rate that reflects the premium cost of Biomethane. It also points out that there is a longer-term customer interest in ensuring that its product offerings meet the expectations of customers and potential customers and also submits "[a]ll customers benefit from initiatives to retain and add throughput to the Terasen system because added throughput spreads system costs over a larger base, thus resulting (all else equal) in lower delivery rates." Finally, Terasen submits that that the proposed rates are just and reasonable, given the benefits to all customers associated with the premium offering, and the principled basis Terasen has proposed for cost allocation. (Terasen Final Submission, pp. 19, 51)

4.9.6 Intervener Submissions

BCOAPO strongly supports "thoughtful and economical efforts to increase the use of renewable resources and reduce GHG emissions in the province" and believes that such efforts are in the public interest. However, BCOAPO submits that the costs of achieving that goal must be distributed appropriately and through correct mechanisms. While BCOAPO has some concerns, it supports the Application noting the small annual costs to non-participants. (BCOAPO Final Submission, pp. 2-3)

BCSEA supports the concept that customers in the Biomethane Program should pay for the cost of Biomethane and all customers should pay for the cost of making the Biomethane Program available. BCSEA agrees with Terasen that the principle is analogous to the Commission-approved treatment of the Customer Choice Program. (BCSEA Final Submission, p. 6)

The CEC supports Terasen's efforts to address the long term management of risk by way of this initiative to ensure retention and addition of customers to the system in order to spread distribution costs over a larger base. The CEC submits that Terasen's rates should be set on the basis of cost causality for utility service rates and believes that the Shareholder should not be inherently responsible for the cost of any of the proposed Biomethane Service. The CEC further submits that Terasen has correctly defined cost allocation methodologies appropriate for utility service and has proposed to apply them correctly. Finally, the CEC notes that the allocation of marketing, advertising, promotion and education back to all customers appears to be standard practice and that there is no quality evidence on the record to support alternative cost-allocation methodologies. The CEC submits that the Commission should give weight to the fact that the magnitude of the expenditures for this new service does not warrant revision of the cost allocation methodology at this time. "The broad interest of customers in GHG reduction and the potential for renewable options makes the cost allocation to all customers appropriate." (CEC Final Submission, pp. 4-5)

Commission Determination

The Commission Panel is cognizant of the new post *CEA* environment which is challenging TGI to innovate and adapt its utility service model. In this regard, the Commission Panel agrees with Terasen and the CEC that it is in the long term interest of all Terasen utility customers that new initiatives contribute to retention and the addition of throughput in the system, which will result in system costs being spread over a larger base. The Commission Panel also notes the dual role of the Commission in balancing the interests of ratepayers and the utility.

It is in this context that the Commission Panel approves the cost allocation methodology proposed by Terasen Gas for the test period as just and reasonable. It is important to consider this finding as a test period approval only, as another determination will be required at the point of the review for Phase 1. The Commission Panel also notes the "strings-attached" support given by BCOAPO. Because in this Application the small levelized annual cost to non-participants, (estimated at 38 cents to an average customer) is not material, it is relatively easy to approve the methodology. Small programs like this give Terasen an opportunity to develop the markets and test customer demand under the auspices of the utility regulatory model. However, as the Biomethane business grows and matures the issue of "who pays" becomes more significant. In the long term, once the markets have evolved, a time may come to take a fresh look at the role of the utility vis-a-vis competitive markets as discussed in Section 6.0.

The Commission is concerned that distribution (or transmission) pipeline extensions to connect the projects are included in the costs allocated to all customers. These costs can vary widely from project to project, and arguably are more akin to upgrading costs. However, considering the relatively modest amount of those connection costs for the two projects at hand and the test period nature of this approval, the Commission will only require that this cost be identified and monitored.

The Commission Panel notes that TGI has budgeted $160,000, $240,000 and $300,000 for customer education in 2010, 2011 and 2012 respectively, but has not sought approval of these. The Commission accepts that these expenditures will be recorded in the appropriate deferral account. However, the Panel notes that recovery in future rates of these amounts will be subject to future review by Commission.

Specific approvals for the Biomethane Energy Recovery Charge, the Biomethane Variance Account and other components of the approvals sought will be addressed in Section 5.0.

4.10 Other Project Risks

This Section addresses project risks other than risk of stranded assets for the CSRD and Catalyst Projects and summarizes Terasen's mitigation measures.

4.10.1 Risk to Gas Supply Portfolio

TGI states that quantity of biogas and Biomethane from the Projects will not impact its overall gas supply portfolio. At these early stages with low levels of supply, entering the two agreements will not cause Terasen to alter its other portfolio or planning practices or contracts. Terasen further states that because of this, the amounts of new supply promised will not leave the Company vulnerable to either additional market purchases or access to alternative sources of conventional gas to replace biogas or Biomethane that is not delivered. However, Terasen also states that as additional biogas and Biomethane purchase agreements come on line it will reassess the impact on its overall portfolio. Finally, Terasen points out that the Catalyst agreement includes the full costs of replacement gas in the non-performance remedies within the agreement. (Exhibit B-1, pp. 92, 101, 102)

4.10.2 Risk of Failure to Supply Biomethane

In the case of the CSRD Project, Terasen notes that the composition of buried waste in the Salmon Arm landfill is not fully predictable and therefore neither is the gas production from the landfill. As a result, there is the potential for an interruption in either supply of raw gas or Biomethane. It states that it has mitigated these risks in two ways:

- From the gas system perspective, planning will be done assuming that biogas is not available;
- From a financial perspective, the compensation for sale of gas is based on sellable (purified) gas. The CSRD will not receive any payments unless Terasen can successfully upgrade the biogas and inject it into the distribution system. Further, there is also a minimum supply requirement that if not met will trigger a contractual default.

(Exhibit B-1, p. 92)

In the case of the Catalyst Project, Terasen explains that failure of Catalyst to provide gas to the Company could result from events such as loss of waste stream supplies (anaerobic digester feedstock), failure to meet gas specifications, breach of contract or poor financial health resulting in interruption to operation. Terasen states that it has addressed these risks through a non-performance clause in the agreement. (Exhibit B-1, p. 102)

4.10.3 Operational and System Risk

Terasen Gas takes the position that "in the unlikely event that a failure of the biogas upgrading equipment occurs", contaminants harmful to the pipeline or disruptive to customer service could occur. In order to mitigate this risk, Terasen will ensure the upgrading system be designed to self-monitor for abnormal conditions and, as owner of the upgrading equipment, will always have the final control of the gas quality. Should Biomethane not meet these specified quality, Terasen will immediately stop delivery to customers and evaluate the problem with the CSRD. (Exhibit B-12, p. 93)

To mitigate the same concerns in the case of Biomethane delivery from Catalyst, the agreement requires that Biomethane must meet Terasen Gas specifications and includes the right of Terasen to interrupt delivery from the project if the gas does not meet these quality specifications. The Catalyst facilities will also be linked with TGI's gas control system to allow real time monitoring of the quality sampling equipment. Terasen further states that the pressurized flows of conventional natural gas will automatically backfill and replace the lost flow of Biomethane during any such stoppage. (Exhibit B-1, p. 102)

4.10.4 Facilities Cost Risk

Terasen states there is some risk that costs for the facilities could be higher than expected, but notes it has followed best practices for cost projections and used conservative estimates for interconnection and monitoring equipment to mitigate this risk. Terasen further states that for the upgrading plant it has negotiated a fixed price contract with the supplier. Finally, Terasen notes that in the CSRD cost-of-service analysis it has included a 10 percent contingency allowance on capital costs. (Exhibit B-1, p. 93)

In the case of the Catalyst Project, Terasen has followed the above practices for the interconnection and monitoring equipment to mitigate risk. In addition, it has included a 20 percent contingency allowance on capital costs. (Exhibit B-1, p. 103)

Commission Determination

The Commission Panel finds that Terasen Gas has taken prudent steps to mitigate risks inherent in innovative new projects such as the CSRD biogas and Catalyst Biomethane Projects. However, the Commission Panel notes that after the test period there will be a requirement for a more comprehensive review of who owns the upgrading facilities as discussed in Section 4.5. This review should also provide an opportunity for a further risk assessment.

4.11 Post Implementation Review and Reporting

In its Application, Terasen acknowledges that following implementation a thorough review of the Biomethane Program will be necessary. The Company proposes that the review be carried out five years following the Program launch and be made up of two components; a post-implementation report and a workshop. The report and workshop will address the following elements:

- How many and what types of supply projects have been developed;
- Customer segmentation;
- Enrollment and attrition Rates; and
- Review of the costs incurred and their recovery.

Terasen notes that the five year time span will be sufficient to allow the industry to mature through the development of additional projects and to validate the research which has been conducted into the residential and commercial markets. In the ensuing period, Terasen proposes to report on the development of the Program through its revenue requirement applications as well as report on the costs of Biomethane gas as part of the regular quarterly gas cost reporting which has been established with the Commission. (Exhibit B-1, p. 81)

BC Hydro had no comments in its submissions with respect to the post-implementation review and reporting process. Likewise, the BCOAPO had no comments concerning the timing and review of the Program. However, based on the BCOAPO's stated position that the Projects should be made a "one off" and not be taken as a template for further ventures into the gas commodity refining and the supply line of business, it can be inferred that it is BCOAPO's view the timeline for review of the Projects could be shortened. (BCOAPO Final Submission, p. 3) BCSEA stated in its submission that it was in support of what Terasen has proposed. (BCSEA Final Submission, p. 7) The CEC recommends that the Commission request annual reporting encompassing on-going investment expenditures, operating costs and updated projections for customers, as well as volumes and costs in addition to what has been proposed. (CEC Final Submission, p. 5)

In Reply to the CEC submission, Terasen states that if the Commission wishes it to address the additional information in annual reports it will do so. However, it notes that what has been proposed is redundant as it will be addressed more appropriately in TGI's future resource plans and/or revenue requirements applications. Terasen concludes by pointing out that the costs for what it describes as redundant reporting will be borne by customers. (Terasen Reply, p. 3)

Commission Determination

As outlined in Section 4.6, the Panel has placed limits on total Biomethane production for all projects undertaken in this program. Our purpose is to allow Terasen the flexibility to expand the program from the two Projects. However, we also want to ensure there is the opportunity for stakeholders to better understand and review the success or failure of this Program and whether the proposed Biomethane Offering Model is appropriate before it is allowed to grow to the point where it would be difficult to reverse without a significant financial impact. In keeping with this view, the Panel finds the five year time period proposed by Terasen for a full review of the program to be unnecessarily lengthy. We believe that reducing this time period to a period of two years will allow TGI sufficient time to launch some additional projects and undertake the analysis necessary to provide an adequate basis for review. **Accordingly, the Commission Panel, to safeguard the public interest, has determined that Terasen will be granted a period of two years from the date of the Order issued concurrently with this Decision for review and preparation of further applications in support of expansion of this Program.**

The Panel, acknowledging the CEC recommendations, expects Terasen's analysis and report to be comprehensive. Our requirements include but are not limited to examination of the following information:

- Full financial review of all projects (individual and aggregate numbers) which have been undertaken;
- Validation of the market research;
- Enrollment and attrition rates;
- Costs and assessment of customer marketing/education programs;
- Customer segmentation and targeting;
- Assessment of Pricing Methodology and Principles for Cost Recovery;
- Future Projects that are under consideration
- Forecasts of Biomethane supply as well as customer demand and anticipated update for the next ten year period.

5.0 OTHER APPROVALS REQUESTED

5.1 Biomethane Variance Account

The Commission Panel approves the creation of a rate base deferral account, called the Biomethane Variance Account, as proposed by Terasen. This account will capture costs to procure and process consumable Biomethane gas as well as revenues collected through Biomethane energy recovery components of rates. The Commission Panel finds the BVA to be a reasonable mechanism to accumulate any differences in Biomethane service costs and revenues. Further, the Panel accepts Terasen's quarterly reporting process and Biomethane Energy Recovery Charge rate setting mechanism as proposed in the Application as this methodology is consistent with the Company's existing gas reporting and rate setting methodologies.

Commencing January 1, 2012, the treatment of all costs related to and resulting from ongoing Biomethane operations will be reviewed by the Commission as a component of Terasen's Revenue Requirements Application (RRA). **Within TGI's RRA for 2012 and onwards, Terasen is directed to include a separate section providing actual and forecasted Biomethane operating, maintenance and capital costs and an analysis of these costs.** This disclosure is to include, amongst other things, a breakdown of costs incurred by category of past and projected years and an explanation of the financial results experienced and expected in the test period. Details of all accumulations within the BVA should also be provided.

The Commission Panel further approves Terasen's request for two new non-rate base deferral accounts (New Deferral Accounts) to capture the following costs, as described by the Application, incurred prior to January 1, 2012:

i) Costs of service associated with the capital additions to the delivery system; and
ii) Operating and maintenance costs applicable to all customers (attracting AFUDC).
(Exhibit B-1, pp. 110-111)

As costs associated with the New Deferral Accounts will be incurred in the remaining portion of the revenue requirement period, the Panel accepts the proposed deferral treatment until January 1, 2012.

In the Application, the Company seeks to recover costs accumulated in the New Deferral Accounts from all non-bypass customers over a three year period by amortizing them through delivery rates commencing January 1, 2012. (Exhibit B-1, p. 111) **The Commission Panel approves this request as an acceptable recovery period given the nature and forecasted extent of these costs.**

As part of its 2012 Revenue Requirements Application, TGI is directed to report the total values accumulated in the New Deferral Accounts from inception as well as a breakdown of the costs accumulated in the accounts by nature and dollar amount. Further, the Company is directed to present within its annual regulatory report to the Commission, the total value of each of these deferral accounts, net of any amortization. This is to be done each year until the remaining balance is $nil.

Terasen also seeks to set the Biomethane Energy Recovery Charge at $9.904/GJ and seeks approval that the Biomethane Energy Recovery Charge is set at this amount effective October 1, 2010. (Exhibit B-1, p. 117) Because the rate of $9.904/GJ is well below the maximum rate of $15.28 previously established in Section 4.6, **the Panel accepts the Biomethane Energy Recovery Charge at $9.904 for all Rate Schedules effective October 1, 2010 to recover forecasted costs.**

5.2 Rate Schedules

TGI seeks approval of rate schedules of both Phase 1 and 2 of the proposed Offering. TGI proposes that the Commission approve Rate Schedules 1B and 11B and amendments to Rate Schedule 30 effective October 1, 2010 (Phase 1), and also approve Rate Schedules 2B and 3B for commercial customers effective January 1, 2012 (Phase 2). TGI notes that Rates Schedules 1B, 11B and the amendments to Rate Schedule 30 reflect the rate methodology described in this Application. Rate Schedules 2B and 3B reflect methodology which TGI indicates is consistent with Phase 1 as well as offering higher blends of Biomethane which TGI believes may appeal to commercial customers. TGI also requests an amendment to its General Terms and Conditions to include reference to the Biomethane Offering. (Exhibit B-1, pp. 52-53 as amended by Exhibits B-1-1 and B-3)

TGI believes it is important to approve both Phase 1 and 2 Rate Schedules at this time for two reasons. The first reason is to avoid the additional regulatory cost to review Phase 2 as a separate proceeding in the future, especially given the body of evidence submitted in this proceeding, and secondly to avoid future delays on timely expansion. (Terasen Final Submission, p. 40)

TGI indicates its intent to file with the Commission additional tariff schedules when the opportunity to expand the program exists. Also, TGI notes that the Biomethane rollout to other regions and rate classes will be driven by customer uptake rates in Phase 1 combined with supply availability. TGI proposes that as such, customer offerings and rate schedules could be modified from time to time. (Exhibit B-1, p. 53)

CEC submits that the proposed phase in of the TGI Biomethane service is reasonable and sensible and agrees that setting rates now is appropriate and may avoid unnecessary regulatory proceedings. (CEC Final Submission, p. 4)

BCSEA accepts TGI's explanation for offering the Biomethane Program to residential customers initially and later expanding the program to make it available to commercial customers and possibly offer Biomethane blends higher than the 10 percent proposed in Phase 1. Also, BCSEA accepts TGI's rationale for seeking approval for the Phase 2 rate schedules at this time. (BCSEA Final Submission, p. 6)

BCOAPO and BC Hydro express no position on tariff matters.

Commission Determination

The Commission Panel approves TGI's Biomethane new Rate Schedules 1B, 11B, 2B and 3B and the proposed amendments to existing Rate Schedule 30 as well as requested changes to TGI's General Terms and Conditions. The Commission Panel finds that sufficient evidence has been presented in this proceeding for it to determine that the proposed Rate Schedules are just and reasonable based on the proposed allocation methodology. It therefore approves them for Phase 1 and 2 of the Biomethane Program. However, if the new Rate Schedules 2B and 3B, when filed, deviate from the methodology described in the Application, the Commission may determine further regulatory process is necessary for those Rate Schedules. **In addition, the Panel directs TGI to provide to the Commission any future proposed Biomethane Rate Schedules or amendments to schedules at least 60 days in advance of their proposed effective date.** If the Commission identifies Biomethane program matters for those Rate Schedules that deviate from the methodology described in the Application, the Commission may determine that further regulatory process is necessary before approving any proposed rate offerings or changes related to TGI's Biomethane Program.

6.0 OTHER COMMISSION PANEL CONSIDERATIONS

This Application for approval of a Biomethane Program and Supporting Business Model is just one of a number of projects Terasen is contemplating as means of dealing with the new environment which has resulted from passage of recent legislation including the *Clean Energy Act*. A number of other new initiatives have been outlined as being under consideration within the Company's 2010 Long Term Resource Plan which was filed with the Commission in July of this year. Collectively, these represent a significant departure from the role Terasen has traditionally played as a public utility. As the Company moves forward with what is a new business model, the issue becomes how to best reconcile those instances where it has moved to a different position on the supply side or is undertaking activities which are more characteristic of a non monopolistic company dealing within a competitive market. In undertaking these new initiatives questions arise as to whether they should be allowed within a regulatory framework and where this leaves the ratepayer with respect to who bears the risk.

This Hearing has dealt with a number of questions related to Terasen's departure from the status quo. Included among these are the following:

- The provision of biogas upgrading services representing a move up the supply chain.
- Principles governing the allocation of costs to ratepayers.
- The risk of stranded assets and resultant question of who pays.

In order to facilitate the process and avoid unnecessary impediments, the Commission Panel chose to deal with this application with the understanding that it represents a test program which will provide valuable information and answers to the question as to how best to handle this model on a go forward basis. Accordingly, the Panel provided direction with respect to Terasen's proposal to own the upgrading facilities in some instances, share costs for the Program among various ratepayer groups and place overall risk for the Program on the broad ratepayer group. However, the Commission Panel would like to be clear that these decisions were made to facilitate the test program only. Following the filing of the Post Implementation report, the Commission may decide to fully review the model and make other determinations based on the information or lack thereof in that report.

As to the larger questions involving the impact of Terasen's proposed new business model, the Commission Panel does not consider it appropriate to answer these questions within the context of this Hearing. However, we do believe that the changes being contemplated and the issues which arise from them are significantly important to warrant a formal process to deal with them at a future date.

7.0 SUMMARY OF DIRECTIVES

This Summary is provided for the convenience of readers. In the event of any difference between the Directives in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

	Directive	Page
1.	The Commission Panel therefore finds that the Application is consistent with British Columbia's energy objectives and Provincial Government energy policy.	27
2.	The Commission Panel accepts TGI's estimate of its potential Biomethane supply and finds this supply to be sufficient to justify moving forward with the Biomethane Program but the Panel also acknowledges the limited data available to support this estimate.	30
3.	The Commission Panel finds that TGI has proposed reasonable techniques to address the risk of Biomethane shortfalls if short-term supply estimates are overstated. Further, the Commission Panel approves TGI's proposal to purchase carbon offsets and to recover costs through the Biomethane Variance Account in the event of under-supply of Biomethane, at a per gigajoule unit price not to exceed the difference between the Biomethane Energy Recovery Charge and the Commodity Cost Recovery Charge in effect at that time.	30
4.	The Commission Panel finds that the research presented by Terasen supports the position that there is likely to be sufficient demand to justify moving forward with a Biomethane Program.	34
5.	Accordingly, we approve the Purchase Agreements with the CSRD and Catalyst, and expenditures related to the facilities for both of these Projects.	34
6.	Therefore, we have determined the scope of the Biomethane Program should be limited until such time as actual results can be analyzed and more definitive conclusions drawn.	34

7.	Accordingly, the Commission Panel directs that Terasen's costs of the upgrading project be segregated so they may be compared with costs of other potential upgrading operations by other industry participants in the future. The Commission Panel further directs that the upgrading business be kept sufficiently distinct so as to be severable, should the Commission determine that this business ought to be conducted through a separate entity in the future.	39
8.	Accordingly, we have determined that future energy supply contracts for the purchase of biogas or Biomethane that meet the criteria listed in Section 3.3.3 of these Reasons with the following additional criteria will meet the filing requirements in sections 71(1)(a) and 71(1)(b) of the *Act*: • The total production of Biomethane for all projects undertaken under what has been approved in this Decision does not exceed an annual purchase in each year of 250,000 GJ. • The maximum price for delivered Biomethane on the system is set at $15.28 per GJ.	41
9.	It is in this context that the Commission Panel approves the cost allocation methodology proposed by Terasen Gas for the test period as just and reasonable.	51
10.	Accordingly, the Commission Panel, to safeguard the public interest, has determined that Terasen will be granted a period of two years from the date of the Order issued concurrently with this Decision for review and preparation of further applications in support of expansion of this Program.	56
11.	Within TGI's RRA for 2012 and onwards, Terasen is directed to include a separate section providing actual and forecasted Biomethane operating, maintenance and capital costs and an analysis of these costs.	58
12.	The Commission Panel approves this request as an acceptable recovery period given the nature and forecasted extent of these costs.	59
13.	As part of its 2012 Revenue Requirements Application, TGI is directed to report the total values accumulated in the New Deferral Accounts from inception as well as a breakdown of the costs accumulated in the accounts by nature and dollar amount. Further, the Company is directed to present within its annual regulatory report to the Commission, the total value of each of these deferral accounts, net of any amortization. This is to be done each year until the remaining balance is $nil.	59

14.	The Panel accepts the Biomethane Energy Recovery Charge at $9.904 for all Rate Schedules effective October 1, 2010 to recover forecasted costs.	59
15.	The Commission Panel approves TGI's Biomethane new Rate Schedules 1B, 11B, 2B and 3B and the proposed amendments to existing Rate Schedule 30 as well as requested changes to TGI's General Terms and Conditions.	61
16.	In addition, the Panel directs TGI to provide to the Commission any future proposed Biomethane Rate Schedules or amendments to schedules at least 60 days in advance of their proposed effective date.	61

Dated at the City of Vancouver, in the Province of British Columbia, this 14th day of December 2010.

Original signed by:

Dennis A. Cote
Panel Chair

Original signed by:

Alison A. Rhodes
Commissioner

Original signed by:

Liisa A. O'Hara
Commissioner

Ontario Energy Board

Learn More About the OEB's Green Energy Initiatives

The *Green Energy Act, 2009* establishes important responsibilities for the Ontario Energy Board and other entities in achieving the objectives of conservation, promotion of renewable generation, and technological innovation through the smart grid.

The Ontario Energy Board has three new objectives:

1. The promotion of renewable energy, including the timely connection of renewable energy projects to transmission and distribution systems;

2. The promotion of conservation and demand management; and

3. The facilitation of the implementation of a smart grid

The OEB is committed to integrating the objectives in the *Green Energy Act* with the Board's traditional mandate around economic efficiency, cost effectiveness, consumer protection, and promotion of public confidence in the sector.

The Board has a number of initiatives underway to facilitate the creation of the clean, green energy supply in Ontario.

RESOURCES

- Green Energy Initiatives - Frequently Asked Questions
- Get Connected - Information on Generation Programs (FIT, microFIT, Net Metering)
- Webcasts - Green Energy Act Implementation Readiness

INITIATIVES

Conservation & Demand Management

The Board is currently working with the Ministry and the OPA to develop conservation targets and a reporting process for LDCs.

- Directive issued by the Minister of Energy & Infrastructure to the Ontario Energy Board (April 23, 2010)
- Conservation and Demand Management Code For Electricity Distributors (EB-2010-0215) (June 22, 2010)
- Electricity Conservation and Demand Management Targets (EB-2010-0216) (June 22, 2010)

Distribution System Plans for Renewable Generation Connection and Smart Grid

Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence (EB-2009-0397)
The Board issued its *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence* on March 25, 2010.

- Cover letter - issued March 25, 2010
- Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence - issued March 25, 2010
- Cost Award Matters

- **Draft Filing Requirements: Distribution System Plans under the Green Energy Act** (December 18, 2009)
  - Letter inviting comments on the draft Filing Requirements - issued December 18, 2009
  - Draft Filing Requirements: Distribution System Plans under the Green Energy Act
  - Cost Eligibility Requests - received January 5, 2010
  - Decision on Cost Eligibility - issued January 27, 2010

- **Distribution System Planning Guidelines** (June 16, 2009)
  The Board has issued preliminary guidelines to assist distributors in creating their distribution system plans.
  - Letter to distributors outlining Board's plans and information requirements
  - Guidelines: Deemed Conditions of Licence on Distribution System Planning (G-2009-0087)

Infrastructure Development & Planning for Renewable Generation

Regional Planning (EB-2011-0043)
The Board initiated a consultation aimed at promoting the cost-effective development of electricity infrastructure through coordinated planning on a regional basis between licensed distributors and transmitters.

- Letter: Announcement of consultation process - issued April 1, 2011

Rate Protection and the Determination of Direct Benefits under Ontario Regulation 330/09 (EB-2009-0349)
The Board initiated a consultation process to address how the Board should, in accordance with the requirements of Ontario Regulation 330/09, determine the direct benefits that accrue to the consumers of a distributor when that distributor has incurred costs to make an eligible investment in its distribution system to accommodate a renewable energy generation facility.

- Letter: Announcement of consultation process - issued September 25, 2009
- Cover Letter - issued December 14, 2009
- Staff Discussion Paper - issued December 14, 2009
- Chart: Regulation 330/09; DCCR amendments, Direct Benefits consultation - issued December 14, 2009
- Read the comments received January 18, 2010
- Stakeholder Meeting presentations – posted February 25, 2010
- Read the comments received March 11, 2010
- Cover letter - issued June 10, 2010
- Report of the Board - issued June 10, 2010

Transmission Project Development Planning (EB-2010-0059)
The Board has issued a Staff Discussion Paper for stakeholder comment. The Paper proposes a process to designate transmitters to undertake development work for transmission projects identified as required for accommodating renewable generation by the OPA in its Economic Connection Test.

- Board letter on participation - issued April 19, 2010
- Staff Discussion Paper - issued April 19, 2010
- Framework for Transmission Project Development Plans - issued August 26, 2010
- Filing Requirements for Transmission Project Development Plans - issued August 26, 2010

Distributor Owned Generation (EB-2009-0411)
The Board has issued a Notice of Proposal To Amend Codes with proposed amendments to the Distribution System Code and Affiliates Relationship Code for Electricity Distributors and Transmitters to reflect the ability of electricity distributors to own and operate certain renewable and other generation facilities as well as energy storage facilities.

- Notice of Proposed Amendments - issued December 10, 2009
- Read the comments received January 28, 2010
- Notice of Amendments to Codes - issued March 11, 2010

Setting of a Just and Reasonable Rate to Recover the Costs Associated with Embedded Generators
The Board has commenced a proceeding on its own motion to determine a just and reasonable rate to be charged by an electricity distributor for the recovery of costs associated with an embedded generator having a nameplate capacity of 10kilowatts or less that meets the eligibility requirements of the Ontario Power Authority's microFIT program.

- Letter to all Licensed Electricity Distributors, Generators and other interested parties in respect of metering, settlement and billing of "micro" distributed generation under the Feed-in-Tariff (FIT) Program - issued July 17, 2009
- Notice of Proceeding / Procedural Order No. 1 - issued September 21, 2009
- Decision and Procedural Order No. 2 - issued October 22, 2009

The Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors
The Board is consulting on more innovative approaches to cost recovery for electricity infrastructure projects. Availability of the mechanisms will be associated primarily with investments relating to the accommodation of renewable generation and smart grid development.

- Staff Discussion Paper - issued June 10, 2009
- Report of the Board - issued January 15, 2010

Completed Initiatives:

Distribution System Code Amendment (EB-2008-0102)
The Board issued Amendments to the Distribution System Code for simplifying the process for the connection of smaller sized generation facilities.

- Notice to Amend a Code: Amendments to the Distribution System Code – issued February 12, 2009

Guidelines for Regulatory and Accounting Treatments for Distributor-Owned Generation Facilities (G-2009-0300)

The Board has issued Guidelines for the regulatory and accounting requirements for electricity distributors that own and operate renewable energy generation.

- Guidelines for Regulatory and Accounting Treatments for Distributor-Owned Generation Facilities - issued September 15, 2009
- Cover Letter - issued September 15, 2009

Distribution System Code and Retail Settlement Code Proposed Amendments (EB-2009-0303)

The Board proposes amendments to the Distribution System Code and the Retail Settlement Code. The amendments are being proposed in anticipation of a significant number of renewable generation projects that are anticipated in response to the Ontario Power Authority's proposed feed-in-tariff program.

- Letter to all Licensed Electricity Distributors, Generators and other interested parties in respect of metering, settlement and billing of "micro" distributed generation under the Feed-in-Tariff (FIT) Program - issued July 17, 2009
- Notice of Proposed Amendments to the Distribution System Code and Retail Settlement Code - issued August 5, 2009
- Read the comments received August 26, 2009
- Notice of Amendment to a Code - issued September 21, 2009

Distributed Generation Connection Cost Responsibility (EB-2009-0077)

The Board is revising its current approach to assigning cost responsibility as between a distributor and a generator in relation to the connection of generation facilities to distribution systems.

- Notice of Proposed Amendments to the Distribution System Code to revise its current approach to assigning cost responsibility - issued June 5, 2009
- Read the comments received June 30, 2009
- Notice of Revised Proposed Amendments to the Distribution System Code - issued September 11, 2009
- Read the comments received Oct 5, 2009
- Notice of Amendment to a Code: Amendments to the Distribution System Code - issued October 21, 2009
- Notice of Revised Proposed Amendments to the Distribution System Code - issued March 11, 2010

Distribution Capacity Allocation Reforms

The Board is taking steps to ensure viable generation projects, particularly renewable generation projects, are connected to the distribution system in a timely manner.

- Notice of Proposed Amendments to the Distribution System Code to enhance the generation connection process - issued May 14, 2009
- Read the comments received June 11, 2009
- Notice of Proposed Revised Amendments to the Distribution System Code to enhance generation connection process – issued August 10, 2009
- Read the comments received August 31, 2009
- Notice of Amendment to a Code - issued September 21, 2009

Transmission System Development: Transmission Connection Cost Responsibility

The Board is taking steps to facilitate the timely connection of clusters of renewable energy projects to the transmission system

- Notice of Revised Proposal to Amend a Code: Revised Proposed Amendments to the Transmission System Code - issued April 15, 2009
- Read the comments received May 6, 2009
- Notice of Revised Proposal to Amend a Code: Further Revised Proposed Amendments to the Transmission System Code - issued September 11, 2009
- Read the comments received Oct 1, 2009
- Notice of Amendment to a Code: Amendments to the Transmission System Code - issued October 20, 2009

Green Energy Act Implementation Readiness Program

GEA Implementation Readiness Program

The OEB has an important role to play in ensuring the government's objectives in the *Green Energy Act* are achieved. That includes ensuring that electricity distributors meet the requirements for renewable generation connection, smart grid implementation and conservation and demand management.

To help distributors prepare for their new obligations, the OEB is planning a number of activities over the coming months. These activities are intended to provide practical information to help electricity distributors prepare and implement their new responsibilities.

Page last updated 2011-05-24

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