Terasen Gas

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June 8, 2010

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. ("Terasen Gas")

Application for Approval of:

- **A Biomethane Service Offering and Supporting Business Model;**
- **The Salmon Arm Biomethane Project; and**
- **The Catalyst Biomethane Project**

Attached please find Terasen Gas' Application for Approval of a Biomethane Service Offering and Supporting Business Model, for the Approval of the Salmon Arm Biomethane Project and for the Approval the Catalyst Biomethane Project (the "Application").

The Biomethane Supply Contracts filed under Appendix I and one of the Financial Schedules filed in Appendix J (specifically, Appendix J-3) contain commercially sensitive terms and negotiated rates, and have therefore been filed confidentially under separate cover in accordance with the BCUC Practice Directive related to Confidential Filings.

Pursuant to the Practice Directive, TGI requests that intervenors wishing to review the confidential appendices execute an Undertaking of Confidentiality to maintain confidentiality (a sample of which is found in Appendix N-3 of the Application).

Ten hardcopies of this Application, including the confidential appendices, will be submitted to the Commission. The Application including non-confidential appendices and all subsequent non-confidential exhibits will be made available on the Terasen Gas website under the Regulatory Submissions section for the Lower Mainland at the following link:
http://www.terasengas.com/_AboutUs/RatesAndRegulatory/BCUCSubmissions/default.htm

If you have any questions or require further information related to this Application, please do not hesitate to contact the undersigned.

Yours very truly,

TERASEN GAS INC.

Original signed:

Tom A. Loski

Attachments

cc (email only): Registered Participants in the TGI 2010-2011 RRA Proceeding

Terasen Gas

TERASEN GAS INC.

Biomethane Application

Volume 1 - Application

June 8, 2010

Table of Contents

List of Appendices

Index of Tables and Figures

1 INTRODUCTION AND OVERVIEW

1.1 Introduction

This is an application by Terasen Gas Inc. ("Terasen Gas", "Terasen", "TGI" or the "Company") for Commission approval of the necessary tariff provisions, cost allocation methodology and accounting treatment to allow the Company to introduce an end-to-end business model for the acquisition of Biomethane supply and the sale of a renewable energy, or "Green Gas[1]", offering ("the Application") to Terasen Gas customers. The initial Biomethane supply will come from two proposed supply contracts discussed in this Application. The specific approvals sought are included in Section 14 of this Application.

Biomethane is a renewable and carbon neutral energy source. When used in place of natural gas, it results in the reduction of greenhouse gas ("GHG") emissions. The production of Biomethane from biomass is a more efficient use of this important renewable resource than generating electricity from it. Terasen Gas is proposing in this Application to develop supply of Biomethane from two initial projects. The first, a landfill in Salmon Arm, BC, is collecting the raw Biogas produced in the landfill which Terasen Gas will then upgrade to pipeline-quality Biomethane and inject into our distribution system. The second project is located on a farm in Abbotsford, BC. This project partner will collect agricultural waste and use digestion and upgrading technology to manufacture Biomethane, which will then be delivered to Terasen Gas. The Company anticipates the development of several more Biomethane supply projects in the future, and has proposed a streamlined process to facilitate approval of additional projects.

Market research conducted by Terasen Gas has suggested that our customers have a strong desire to purchase renewable clean energy from Terasen Gas. The data provided by the Company in this Application shows that large numbers of residential and commercial customers want to use Biomethane, far more customers than Terasen Gas can serve with our two initial Biomethane supply projects. To respond to this demand, Terasen Gas is proposing a measured, phased approach which is flexible and scalable to allow us to balance supply and demand for Biomethane.

This Application will allow us to meet the demands of our customers in a safe, reliable and economical manner. At the same time, the development of Biomethane as a resource promotes government's energy policy objectives favouring the use of renewable energy, the efficient use of energy, and reducing GHG emissions.

[1] Throughout this Application, Terasen Gas uses the term "Green Gas" to refer to the proposed program for ease of reading and comprehension. The Company has not yet decided on what the program will be named when launched to customers, but wishes to clarify here that it does not expect the name to be the "Green Gas" program, the term is expected to be used only for the purposes of this Application.

The end-to-end business model outlined in this Application, in the Company's view, is comprehensive, balanced and in the best interests of customers.

1.2 Overview of the Biomethane / Green Gas Business Model

The end-to-end business model for what Terasen Gas refers to as the "Green Gas" program has three components:

A) *The model for acquiring the supply of Biomethane:* This part of the program addresses the logistics of acquiring a reliable supply of Biogas, and safely and reliably upgrading it to Biomethane and injecting it into the Terasen Gas distribution system.

B) *The model for the sale of Biomethane to Terasen Gas customers:* This part of the program consists primarily of the formulation of a rate offering to allow the notional sale of Biomethane to Terasen Gas customers willing to pay a premium price.

C) *The cost allocation and recovery model:* This part of the program describes how costs incurred in support of the Green Gas program are recovered from the appropriate customer groups.

These three core parts of the business model are briefly summarized below and are described in greater detail throughout the Application.

1.2.1 SUPPLY OF BIOMETHANE

The key objective of this Application is to safely, reliably and economically meet the customer demand for renewable, carbon-neutral Biomethane. Terasen Gas' partners will in all cases be responsible for the collection of raw material for producing Biogas and the facilities to produce the Biogas. This represents, by far, the largest portion of the investment required in the production of Biomethane. However, as Terasen Gas is responsible for the relationship between the customer and the delivery of the product they consume, Terasen Gas has the greatest interest in ensuring that the supply of Biomethane from a particular project is of a consistent quality so that it represents a steady supply source. The best way to ensure reliability, safety and the continuous flow of product from the Biomethane supply project to the customer is for the Company to own and operate the upgrading facilities as well as the interconnection facilities. This approach allows Terasen Gas to not only ensure that the Biomethane that is injected into our distribution system is safe, but also that the flow is reliable and dependable for customers.

In some cases, independent operators will be able meet the financial and technical standards Terasen Gas will require of them in order to perform the upgrading task. In such cases,the Company will consider negotiating a contractual relationship to purchase upgraded Biomethane from the project partners. Terasen Gas will in all cases have to retain control of the interconnection facilities to control the injection of Biomethane in to the distribution system.

This supply model will provide Terasen Gas with the necessary flexibility to develop Biomethane as a new renewable energy source.

1.2.2 SALE OF BIOMETHANE TO CUSTOMERS

The Company's customers have expressed a significant interest in purchasing Biomethane from Terasen Gas as an environmentally superior option to conventional natural gas.[2] The Company's proposal is to take a phased approach to the implementation of the Green Gas program in recognition of the limited availability of Biomethane at this time and the scheduled replacement of the existing Customer Information System ("CIS"). The first phase of the offering will involve making a blended Biomethane product available to residential customers commencing October 1, 2010, starting with a blend of 10% Biomethane and 90% conventional natural gas. Phase two will involve launching this 10% blend for small and large commercial customers on January 1, 2012. The Company will also sell Biomethane to on-system (transport customers) and off-system wholesale customers. Terasen Gas will seek to expand these offerings as the program matures and new supply sources are developed.

1.2.3 COST ALLOCATION AND RECOVERY

The Green Gas offering will be a premium product, and customers who choose to participate in the Green Gas offering will have to pay more for it than natural gas to reflect the higher cost of the Biomethane. Terasen Gas is proposing that the costs associated with the end-to-end business model be allocated according to the following principles:

- *First, customers should bear the costs of the energy (Biomethane) they chose to consume.* Consistent with this principle, all costs incurred acquiring Biogas and the cost of service of upgrading it to Biomethane[3] would be aggregated and recovered as a commodity cost for Biomethane from those customers who choose to participate in the Green Gas offering.
- *Second, costs associated with making the Green Gas offering available to all customers should be borne by all non-bypass customers.* This includes costs incurred in ensuring that Biomethane injected into the Terasen Gas distribution system is monitored for quality and is safely delivered to the system. It also includes IT upgrades, program management and customer education.

The proposed allocation methodology will ensure that the rates charged for conventional gas and Biomethane remain just and reasonable.

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[2] For the purposes of this Application, the term "conventional natural gas" will be used to describe natural gas of traditional as well as shale sources currently brought on to the Terasen Gas distribution system and to differentiate this gas from carbon-neutral Biomethane from a biogenic source.

[3] In the event where a project partner can be found that meets the financial and technical standards which Terasen Gas requires for them to own and operate the upgrading equipment, the cost of purchasing Biomethane would be included rather than the cost of raw Biogas.

1.3 Organization of Application

This Application is organized as follows:

- Section 2 provides technical background on the nature of Biogas and the technology available to upgrade it to Biomethane. The discussion includes the interchangeability of Biomethane with conventional natural gas, and the renewable and carbon neutral properties of Biomethane.
- Section 3 discusses recent changes in government policy relating to renewable energy sources, efficient energy use and the reduction of GHG emissions. Terasen Gas discusses how the production of Biomethane and the Green Gas offering advances government's energy policy objectives.
- Section 4 describes the three primary types of "green pricing programs": contribution programs, renewable energy-based programs, and offset programs. The relative success rates of other programs has informed Terasen Gas' decision to pursue a renewable energy-based program in the form of this Green Gas offering.
- Section 5 describes the results of primary research commissioned by Terasen Gas to investigate the interest and willingness of customers to take up a Green Gas offering. The study demonstrates that there is demand for a renewable energy-based program offered by Terasen Gas. The Green Gas program has been structured to reflect the results of this research.
- Section 6 describes the new Tariff provisions supporting the initial residential offering, a subsequent small and large commercial offering, and the sale of excess gas to large volume customers on the Terasen Gas distribution system and at supply hubs for export if necessary. This Section also describes the guiding principles for the development of the Green Gas offering, the program launch plan, and the customer education strategy.
- Section 7 provides Terasen Gas' high-level estimate of the Biomethane supply in British Columbia, identifies potential sources of Biomethane, and discusses the interest of other parties in partnering with Terasen Gas.
- Section 8 describes the supply side of the proposed business model. The Company explains why Terasen Gas owning and operateing upgrading assets is the best way to ensure that the supply of Biomethane will be reliable and consistent. Terasen Gas also explains circumstances under which project partners who meet the Company's financial and technical standards might be able to own and operate the upgrading assets. The Company proposes a maximum unit cost for Biomethane supply, and also proposes an expedited approval process for future supply contracts meeting specified requirements.
- Section 9 describes the two specific Biomethane supply projects, in respect of which Terasen Gas has entered supply contracts.
    - The first project is at a landfill in Salmon Arm, British Columbia. Tearsen Gas has entered into a raw Biogas supply agreement with the Columbia Shuswap Regional District ("CSRD"). Terasen Gas will own and operate the equipment necessary to upgrade the raw Biogas to Biomethane.

- The second supply project is located on a farm in Abbotsford, British Columbia. Terasen Gas has reached an agreement with Catalyst Power Inc. ("CPI") for the supply of (already upgraded) Biomethane.

- Section 10 addresses the allocation of costs and the accounting treatment of those costs.
- Section 11 discusses program and project risks that have been identified and not otherwise described in the Application, and explains how Terasen Gas will mitigate these risks.
- Section 12 details Terasen Gas' consultation, including First Nations consultation, in relation to this Application.
- Section 13 provides the conclusion.
- Section 14 details the approvals sought in this Application.

There are a number of Appendices containing supporting information, including the customer research (see Appendix D), letters of support from various organizations (see Appendix L), and Tariff provisions (see Appendix F).

1.4 Proposed Regulatory Process

Terasen Gas believes that this Application can be addressed efficiently and effectively through a written hearing process. Terasen Gas is open to a negotiated settlement of this Application. Based on discussions with stakeholders, Terasen Gas believes that there is a willingness to consider this approach.

The Company proposes the following timetable. A draft procedural order is found in Appendix N-1. Terasen Gas is cognizant that this is the holiday season and the schedule should allow all parties some flexibility. A competing consideration driving the proposed timeline is that delays in the regulatory process will put pressure and expense on Catalyst Power Incorporated's financing and partnership arrangements, potentially putting this project at risk. The timeline proposed balances these considerations and is consistent with the proposed timing of the phased rollout of the Project.

The proposed timetable is:

Action	Date
Workshop	Thursday, June 24
BCUC IR No. 1	Wednesday, July 7
Intervenor IR No. 1	Wednesday, July 7
TGI Response to IRs No. 1	Friday, July 23
Written submissions on Further Process (NSP vs. Written Process)	Friday, July 30

2 BIOGAS AND BIOMETHANE

2.1 Introduction

Biogas is a readily available supply of renewable gas from landfills, sewage treatment plants, food waste, and agricultural operations. Established technology exists that can be used to upgrade Biogas to Biomethane, which has characteristics that make Biomethane a reliable and safe substitute for natural gas. Moreover, Biomethane is a renewable fuel. The production and consumption of Biomethane is considered carbon neutral. The use of this carbon neutral fuel in place of a carbon positive fuel such as natural gas results in a net reduction of GHG emissions.

In this section, Terasen Gas provides an introduction to Biogas, including describing:

- Why Terasen Gas must invest in equipment to upgrade Biogas to Biomethane;
- What is meant by the terms “Biogas” and “Biomethane”;
- The sources of Biogas;
- How Biogas is upgraded;
- The interchangability of Biomethane with natural gas; and
- Biomethane as a renewable fuel, the use of which can reduce GHG emissions.

2.2 Why Terasen Gas Must Invest in Biomethane Upgrading

As will be demonstrated in Section 3 of this Application, Terasen Gas customers want to purchase and consume Biomethane. Terasen Gas is submitting this Application to ensure that this demand is met safely, reliably and economically. Owning and operating the required upgrading facilities promotes the efficient development of Biomethane supply projects to meet customer demand. It ensures that the Biomethane that is injected into our distribution system arrives safely and economically, and also that the flow is reliable and dependable for customers. The Company is also actively pursuing independent partners who might be entrusted with the task of acquiring Biogas and upgrading it to pipeline-quality Biomethane which Terasen Gas can then purchase, inspect, and inject into our distribution system provided they can meet the safety and reliability standards required for our customers.

It is important to note, however, that Terasen Gas is not proposing to invest in Biogas collection assets. As will be discussed further in Section 8, these assets make up the majority of the capital investment in a Biomethane project, but are currently outside the area of expertise of the Company and as such we are proposing that those assets will, in all cases, be owned and operated by a project partner.

2.3 Definition of Biogas and Biomethane

Terasen Gas uses the term "Biogas" in this Application to refer to a gas substantially composed of methane that is produced by the breakdown of organic matter (biomass) in the absence of oxygen. This breakdown process is also known as anaerobic decomposition. One of the primary products of anaerobic decomposition is gaseous methane, which is also the primary component of natural gas. [4]

Biogas is comprised primarily of methane (CH_4) and carbon dioxide (CO_2) with much smaller amounts of contaminants such as hydrogen sulphide (H_2S) and ammonia (NH_3). Trace amounts of hydrogen (H_2), nitrogen (N_2) and oxygen (O_2) are also occasionally present in Biogas. Usually, the gas is saturated with water vapour and may contain dust particles and organic silicon compounds (siloxanes).

Biogas, in its raw form, can be combusted; however, it does not produce as much heat as natural gas because of the relatively low amount of methane. Moreover, other contaminants may create problems such as corrosion or equipment fouling when put to uses other than simple flaring. In comparison, natural gas found in British Columbia homes and businesses has been refined to remove such impurities and contains almost 100% methane along with a small amount of other combustible gases such as ethane. In order to remove unwanted gases from Biogas, it is processed in a similar fashion to raw natural gas. The primary processing is the removal of non-combustible gas which will increase the heating value of the gas. Elements such as N_2, O_2 and H_2 are monitored to ensure that, if they are present, they are present in such small amounts that they not impact the safety or heating value of the gas. Other contaminants such as H_2S, NH_3, siloxanes and dust are filtered out to ensure that the end product is clean and safe for pipeline injection. For the purpose of this Application, the purification process will be referred to as "upgrading". Once Biogas has been upgraded, it is safely interchangeable with natural gas in the existing distribution and transmission system.

Purified or upgraded Biogas can be referred to as "Biomethane", a renewable form of natural gas. Throughout this Application we will principally refer to this upgraded Biogas as Biomethane. The terms "Biogas" and "raw Biogas" will refer to the gas generated from natural processes which has not yet been upgraded to Biomethane.

The table below shows a high-level comparison of the major typical components of Biogas versus Biomethane. It illustrates the high methane (CH_4) content of purified and upgraded Biomethane.

[4] Gas can also be created from the process of biomass gasification. The gasification process is different than anaerobic decomposition and the resulting gas has a different composition. Gasification creates a gas that primarily consists of hydrogen, carbon monoxide and varying amounts of methane and is more appropriately called "syngas". For the purpose of this application, "Biogas" will refer only to gas that is the product of anaerobic decomposition and, therefore, composed primarily of methane and carbon dioxide.

Table 2-1: Comparison of Biogas and Biomethane

Raw Biogas	Biomethane
40% - 60% CH_4	>96% CH_4
30% - 50% CO_2	<2% CO_2
0% - 2% O_2	<0.4% O_2
0-2000+ ppm H_2S	Sulphur-free
ppm VOC's	VOC-free
H_2O Saturated	<65 mg/m^3 H_2O
Low Pressure	Distribution pressure (>400kPA and <700kPA)

For the purposes of this Application, the term "Green Gas" will be used to describe the specific product offering Terasen Gas is proposing to make available to its customers. The Green Gas offering involves the purchase of a notional Biomethane product because, as described in Section 2.6 below, the Biomethane injected into Terasen Gas' distribution system is physically co-mingled with natural gas.

2.4 Biogas Sources

Biogas is produced from a number of sources. The Biogas from all of these sources is capable of being upgraded to Biomethane as the gas characteristics are generally the same within each of these categories. Four typical sources of Biogas are discussed below[5].

- **On-Farm Digesters:** This term refers broadly to covered storage vessels or lagoons located on operating farms that are used to break down large amounts of organic waste in the absence of oxygen. The typical waste used in on-farm digesters is crop residue or manure generated on the farm. In some cases, the feedstock may be supplemented by industrial organic wastes.

- **Centralized Digesters:** Typically centralized digesters are located near waste sources (such as waste transfer stations, farms or food processing industry) and accept waste from multiple sources with the specific intent of converting that waste to energy. In addition to the centralization of waste that might otherwise be found in an On-Farm Digester, they might accept waste from bakeries, restaurants or food-processing facilities. The key distinguishing characteristic of this type of digester is the fact that organic wastes are collected in different locations and transported to a single location for the purpose of improved operational efficiency that is achieved with higher volumes.

[5] Technology around the world is currently being developed to use "Syngas" created from biomass gasification to create methane. The process to create Biomethane from Syngas is called methanation. For the purpose of this application, this may be considered as a source of Biogas in the future.

- **Municipal or Regional Landfills:** Typical landfills contain large amounts of organic waste from sources such as food, lawns, gardens and bio-degradable items such as paper products.

- **Municipal Sewage Treatment Digesters:** Most modern waste-water treatment plants are designed to separate liquid and solid waste. The solid waste remaining after liquid separation is digested on site in the same manner as an on-farm digester. Sewage treatment digesters differ in that the primary waste is derived from established municipal or regional sewage systems. Many wastewater treatment plants capture the raw Biogas and flare it on site to control odour.

The owners and operators (as well as operational procedures) for each of these general categories are typically similar within the categories. For example, municipal sewage treatment digesters are owned and operated by municipalities and run by operators who have similar skill sets and who follow similar operational procedures. Although the two sources of Biogas being proposed as a part of this Application are an on-farm digester[6] and a landfill, Terasen Gas may potentially obtain Biogas from any of the sources above.

2.5 Biogas Upgrading Processes and Technology

Biogas upgrading involves the removal of contaminants and CO_2, leaving behind the upgraded Biomethane that will be injected in to Terasen Gas' distribution system. In this section, Terasen Gas discusses the removal of contaminants, and the processes by which CO_2 can be removed efficiently and cost effectively.

The contaminants present in Biogas vary in regard to the effects on the system, but in most cases they create equipment issues such as corrosion or fouling of burners. From a safety perspective, contaminants may cause undesirable and potentially hazardous exhaust products. Contaminants are filtered at the source to ensure that they do not reach the pipeline and ultimately the customer. The contaminant removal is typically done using some form of redundant active filtration (such as active charcoal) as well as some kind of filter and/or cyclone process to ensure a reduction in the amount of particulate in the gas.

Once the contaminants are removed, the biggest single constituent in Biogas (other than methane) is CO_2. The presence of CO_2 in Biogas reduces its heating value and the required Wobbe Index[7] of the gas. Therefore, it is important to remove CO_2 efficiently and effectively to produce Biomethane.

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6 A digester is a vessel for digesting especially plant or animal materials. Organic substances, e.g. animal waste, are decomposed in a controlled manner within a vessel so that the products of the decomposition can be processed further.

7 The Wobbe Index is an indicator of interchangeability of fuel gases. It is used to compare combustion energy output at an appliance. If two fuels have the same Wobbe Index, they will have the same energy output at an appliance and can therefore be considered interchangeable.

There are several different commercial methods for reducing CO_2. The most common methods are adsorption, absorption and membrane separation. The principle types of upgrading in use today are Pressure Swing Adsorption ("PSA"), Water Wash, Membrane Separation and Amine Wash. Terasen Gas performed a preliminary evaluation of the different options to help identify an efficient, cost-effective process that could be used for Biogas purification in British Columbia. By ensuring that a cost-effective purification system can be developed, Terasen Gas was able to gain confidence that a cost-effective supply project could be developed. This high-level evaluation was based on initial cost (assuming similar flow rates), operating costs, recovery[8] and purity[9]. The higher the methane content (on a percentage basis) the better the gas will match natural gas.

Two of the four technologies were ruled out after this initial review:

- The Amine Wash technology was examined but eliminated due to its relative high costs for smaller scale projects. It is not economical until Biogas flow is in the range of ten times the expected flows for the known projects in Terasen Gas' service territory. In addition, the use of Amines in the process adds to environmental contamination concerns that occur during operations and maintenance.
- The Membrane Separation technology was also examined and eliminated due to the fact that the purity of gas produced could not meet required pipeline quality specifications without additional gas processing. It has been used successfully in applications where a lower heating value is acceptable, such as direct use or applications where the gas is mixed in low amounts with natural gas.

The two remaining technologies mentioned – Water Wash and PSA – appear comparable in terms of cost, operating expenses, purification capability and purity of the final product based on the preliminary analysis. These two products have performance characteristics that are essentially equal based on the recovery and purity (within 2% of each other).

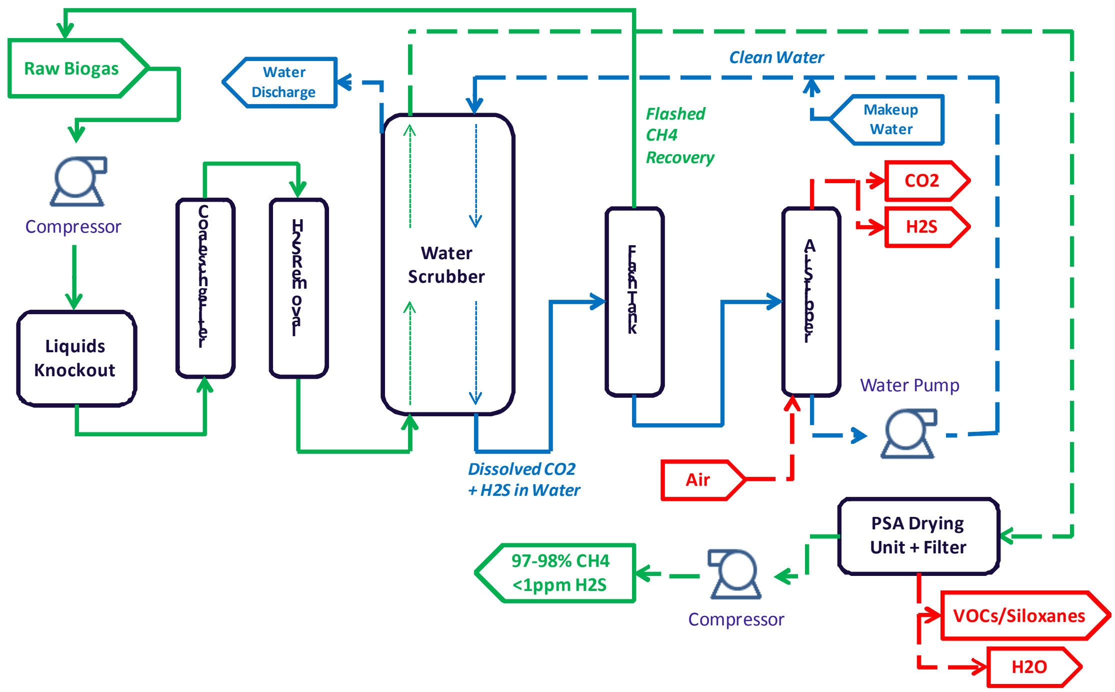
There are companies that specialize in particular methods of gas upgrading. Each of these companies has sufficient expertise to design a process that can remove all contaminants from Biogas and these companies typically offer a complete upgrading plant. The contaminant process may vary depending on the upgrading process because certain processes may remove more than one contaminant. In addition, site conditions, such as the presence of a specific contaminant may require some additional filtration or processing. Site-specific conditions would be considered on a case-by-case basis and the upgrading plant design could vary to account for the differences in the raw Biogas. To illustrate, the two upgrading processes that will be used for the pipeline injection projects are described below.

8 Recovery can be best described as a measure of how much methane exits the process compared to how much methane is in the raw Biogas source.
9 Purity is a measure of how well a technology can remove all non-desirable components from a gas, leaving only methane.

2.5.1 WATER WASH-BASED TECHNOLOGY

Water Wash scrubbing is a process that uses water as a solvent. As discussed above, the process must also account for other contaminants. A basic process is illustrated in the schematic diagram below (Figure 2-1) and described in the points that follow the diagram.

Figure 2-1: Water Wash Process Diagram



1) Raw Biogas is compressed, cooled and fed through a particle filter and an H_2S Removal vessel.
2) Biogas enters the scrubber to mix with pressurized water. CO_2 and H_2S are selectively absorbed.
3) Clean CH_4 passes through a final PSA drying unit and filter to remove moisture and exits the system.
4) CH_4 absorbed in used water is "flashed" off and recycled to the compressor inlet.
5) CO_2 is stripped from used water in Stripper Vessel and vented. Most of water is recycled.

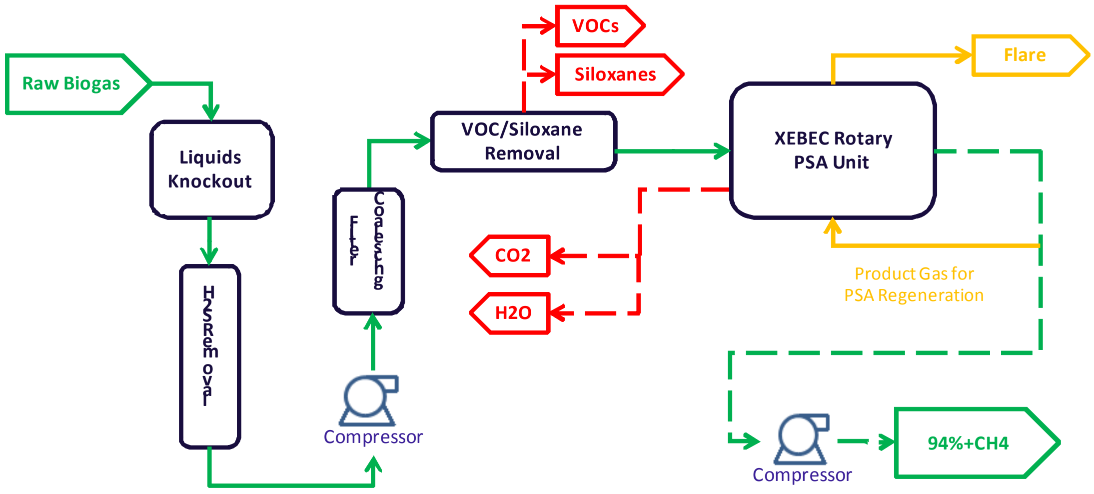
Water Wash systems have been successfully installed and operated for more than 20 years in locations around the world and there is a BC-based sales and service office for this technology (Figure 2-2).

Figure 2-2: Water Wash Biogas Plant, Courtesy of Greenlane Biogas

2.5.2 PSA-BASED TECHNOLOGY

PSA uses a material such as activated carbon in an adsorption process to capture CO_2 and remove it from Biogas (see Figure 2-3). Typically, contaminant removal occurs ahead of the PSA process to avoid contamination of the PSA vessels. The process involves rapid pressurization and de-pressurization of gas in a vessel to remove CO_2, hence the term 'pressure swing'. For successful pressure swing adsorption, the gas must first be dried and have the H_2S removed. Typically, multiple vessels are linked together and the process is repeated from vessel to vessel in a cyclical manner to allow for maximum gas throughput.

Figure 2-3: PSA Process Diagram



1) Raw Biogas is passed through a knockout drum to remove entrained moisture and through a H_2S removal unit.
2) Biogas is compressed to 800 – 1150kPa, cooled, and fed through a coalescing filter to remove oil from compressor and liquids.
3) VOCs and Siloxanes are removed in a desiccant vessel with reusable adsorbent media.
4) High Pressure Biogas enters the pressure swing adsorption vessel, where CO_2 is adsorbed by media while CH_4 passes through.
5) High purity CH_4 product gas is compressed and exits to pipeline.
6) PSA Vessel is regenerated by reducing the pressure in vessel and releasing the CO_2. A small amount of product gas is used to flush out the vessel. The exhaust is flared to remove trace CH_4 and contaminants before being vented.

One company, Xebec Inc, has developed a rotary PSA system that allows for a more rapid process with a smaller footprint (see Figure 2-4 below).

Figure 2-4: PSA System, Courtesy of Xebec Inc.

The application of established upgrading and filtering technologies provides a reliable means of refining raw Biogas supplies in British Columbia.

2.6 Biomethane and Natural Gas Interchangeability

Gaseous fuels are considered to be interchangeable when one gaseous fuel can be substituted for another in a combustion application without materially changing operational safety, efficiency and performance, and without materially increasing air pollutant emissions. Terasen Gas' commitment to customer safety and reliability of gas supply extends to ensuring that Biomethane injected into the Terasen Gas system is interchangeable with natural gas. The Biomethane mixed with natural gas in the system will meet the same quality standard as natural gas and it must perform comparably when injected into pipeline assets and consumed in end use equipment (including customer appliances). This interchangability forms the basis for notional delivery, which is an aspect of the proposed Green Gas offering.

2.6.1 ENSURING INTERCHANGEABILITY

Terasen Gas considers three key factors in confirming the interchangeability of Biomethane and natural gas: heat content, Wobbe Index and gas composition. Table 2-2 summarizes the criteria employed. Details about the three key factors are provided after the Table.

Table 2-2: Biomethane and Natural Gas Interchangeability Factors

Value	Criteria
Heating Value:	$36MJ/m^3 – 41MJ/m^3$
Wobbe Index:	$47.23MJ/m^3 – 51.26MJ/m^3$
Gas Composition:	
H_2S	< $23mg/m^3$
Total S	< 115 mg/m^3
CO_2	< 2 Vol. %
Water Vapour	< 65 mg/m^3
O_2	< 0.4 Vol. %
Total Inerts	< 4 Mol %
Butane Plus	< 1.5 Mol %

- **Heating Value**: The heating value is a measure of the amount of energy delivered per unit volume of gas. It is typically measured in Mega-Joules per cubic meter (MJ/m^3). The heating value for Biomethne will be determined primarily by the content of methane in the gas. A larger proportion of methane, compared to other non-heating gases such as CO_2, will provide more heat content for a given volume of gas.

- **Wobbe Index**: The Wobbe Index is defined as heating value divided by the square root of the specific gravity of a combustible gas. Because the Wobbe Index takes into account the specific gravity of a gas, it helps to provide a prediction of gas flow characteristics. Therefore, the Wobbe Index can be used as a measure to ensure that Biomethane will flow and burn in a similar manner to natural gas in appliances.

- **Gas Composition**: Gas composition is a means of quantifying the "recipe" of a given gas mixture. It takes into account all distinct gases that make up the total gas stream. By matching gas composition as closely as possible to natural gas, Terasen Gas will have confidence that Biomethane will not have any adverse effects such as corrosion on existing equipment or customer appliances.

In order to gain confidence about the interchangeability of Biomethane with natural gas, Terasen Gas participated with other partners in a scientific study of Biogas projects in other locations in North America. The study, entitled "Biogas to Biomethane, Upgrading for injection into the Natural Gas Distribution System" and found in Appendix A of this Application, showed that Biogas can be upgraded to meet safety and performance specifications equal to those of natural gas. In other words, Biomethane is interchangeable with natural gas.

2.6.2 NOTIONAL DELIVERY

The interchangeability of Biomethane with conventional natural gas allows for notional delivery using the existing natural gas distribution system. Biomethane can be injected at one point on the system, displacing conventional natural gas used at that point on the system. The user notices no difference between the gases, which allows the gas to be physically consumed in one place, but be accounted for as sold at another location through displacement.

Notional delivery is a concept that is employed in the trading of commodities. Another example that is in practice on the Terasen Gas distribution system involves gas from marketers in the Customer Choice program flowing to residential customers. If Customer A signs up with Marketer 1 and Customer B signs up with Marketer 2, both marketers are responsible for providing sufficient gas for their customers at the designated receipt points. In actual fact, Customer A may physically receive all, some or even none of the gas actually consumed at their home from Marketer 1 or 2. Neither Customer A nor B will ever know whose molecules they consumed because individual molecules of gas are not tracked. Instead, the system notionally delivers Marketer 1 gas to Customer A and Marketer 2 gas to Customer B, and charges each customer the appropriate rate for the gas they have notionally consumed. This Application proposes a similar notional delivery of Biomethane on the Terasen Gas distribution system.

2.7 Biomethane as a Renewable and Reduced Carbon Fuel

Biomethane is a renewable energy source. The production and consumption of Biomethane is carbon-neutral, and the use of Biomethane in place of a carbon positive energy source like natural gas results in a net reduction in GHG emissions. These three attributes of Biomethane are discussed below.

2.7.1 RENEWABLE ENERGY SOURCE

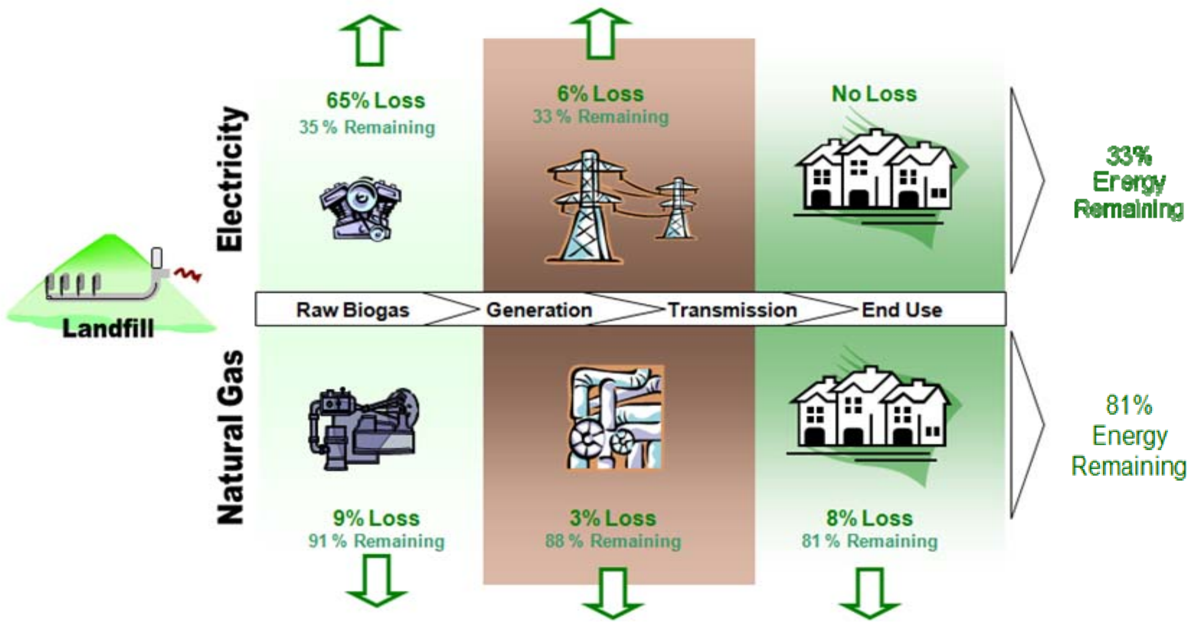
Biogas is a natural product that results from the breakdown of organic matter; therefore, it is considered to be a renewable source of energy. Biogas upgrading is an efficient use of this renewable energy source.

Biogas is the product of waste that would otherwise be lost to the atmosphere if left to dissipate. The origin of the gas is a direct result of the digestion of organic matter by bacteria in a low oxygen environment. All of this organic matter is grown ultimately from plants (whether subsequently fed to animals or not), which remove carbon dioxide from the atmosphere by photosynthesis. As more organic matter is grown, the source of Biogas is also replaced.

Upgrading Biogas to Biomethane for direct consumption in heating applications is the most efficient use of this renewable energy source. The process is between two and three times more efficient than converting raw Biogas into electrical energy for the same end use.

To illustrate, imagine a gas collection system at a landfill that will ultimately provide energy to a residence. The first step in the process (after collection) is to convert that raw energy into a transportable energy, i.e. Biomethane or electricity. The conversion process from Biogas to Biomethane is in the range of 90% efficient. In contrast, when converting to electricity using a reciprocating engine with no heat recovery the efficiency is closer to 35%. This means that before the energy is even transported, 65% of it has been lost. There are also losses in the transmission of energy – approximately 3% for gas and 6% for electricity. In the end use, homes are able to take advantage of all of the electrical energy for heating, whereas gas losses are typically 8% for a high efficiency furnace. Considering both the relative efficiencies of the conversion processes and the relative end use efficiencies, Biomethane is a more efficient use of the raw energy for the end-use of space heating (approximately 81% versus 33%). See below in Figure 2-5 for a graphical illustration.

Figure 2-5: Biomethane vs. Electricity – End Use Efficiency



As illustrated, when converting Biogas to electricity, for each unit of energy available from the resource, only about 33% of it actually does something useful in someone's home. Compared to approximately 81% in useful energy when converting to Biomethane, it makes sense to convert to Biomethane, when possible and economical, in order to make the most of the raw resource.

In certain cases, heat can be recovered from the electricity generation process. This could improve the amount of recovered energy and therefore the overall efficiency of the energy use. When heat recovery is used, the amount of energy that can be used varies depending on the proximity of an energy user – such as a building requiring heat. In the best cases, heat recovery can improve the overall efficiency to be comparable to the use of Biomethane (within a few percent). However, this option adds to the initial capital cost and it may not be realistic in many situations. For example, many landfills could be located away from any significant heat users or customers. Therefore, Terasen Gas believes that in many instances converting Biogas to Biomethane is the most efficient use of the waste resource.

2.7.2 CARBON NEUTRAL CONSUMPTION

The production and consumption of Biomethane is considered carbon (or GHG) neutral because producing and consuming Biomethane will not add to the amount of Carbon released into circulation.

GHGs are gases that once dissipated into the atmosphere, trap infrared radiation from the sun that has been reflected from the earth's surface. In effect, the gases act like a greenhouse –

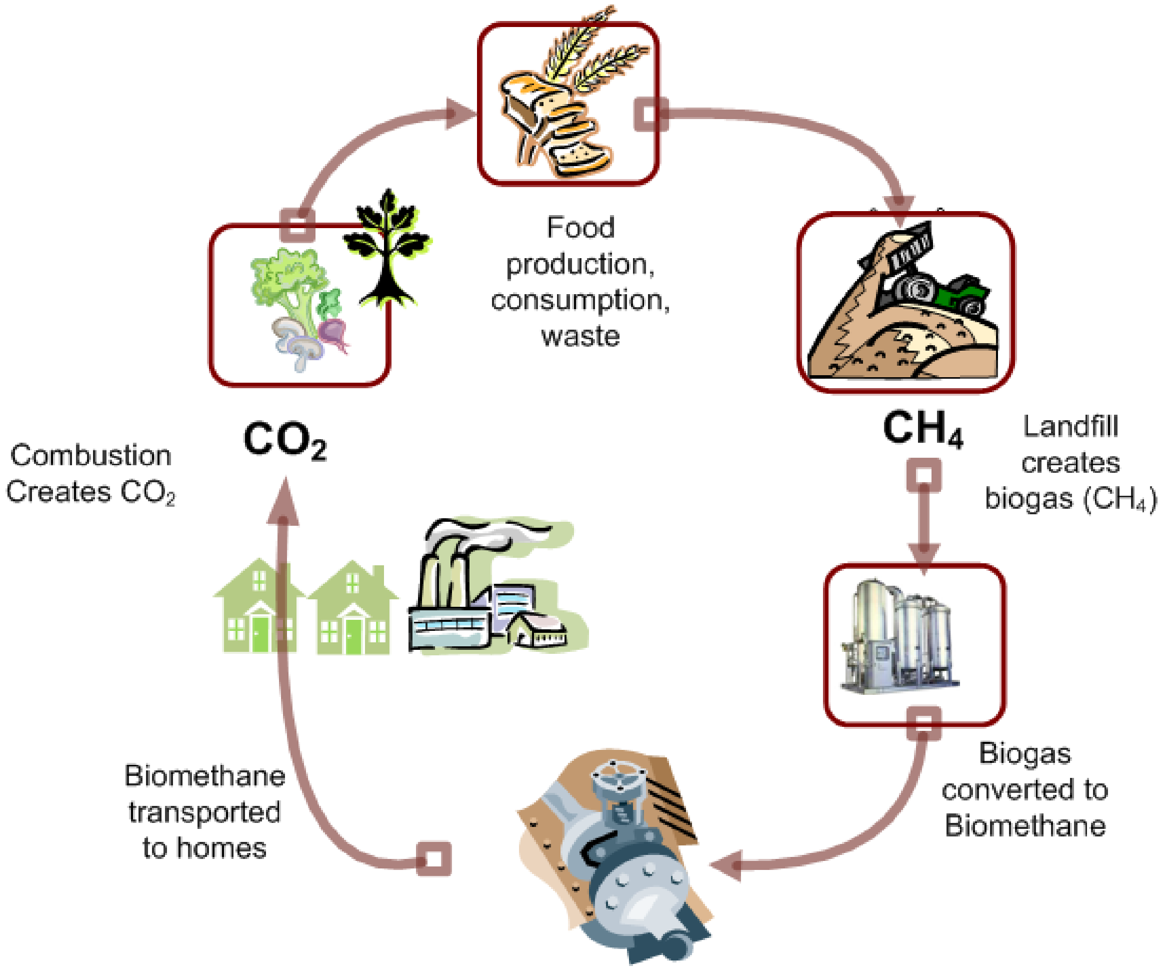
hence the name. Ultimately too much GHG emission will contribute to a warmer planet and climate change. For the purpose of this Application, the most relevant GHGs are carbon dioxide (CO_2) and methane (CH_4). More specifically, CO_2 and CH_4 that come from net carbon emitting sources – such as conventional natural gas wells - can contribute to an increase in GHG emissions. Methane will also be released as the result of the natural decomposition process of organic matter.

Food wasted in a landfill, for example, will produce methane, which must by law[10] be either burned or captured. Burning the methane converts it to carbon dioxide, which is then captured by plants. The plants are grown and harvested and the harvested grain is converted into some kind of food. The leftover waste from that food is then disposed of in a landfill, starting the cycle again. Capturing the Biomethane from the landfill and burning it in an end use application does not add any additional emissions than would otherwise be released through on-site flaring at the landfill.

Figure 2-6 below illustrates that Biomethane, as part of a closed-loop carbon cycle, is not a GHG and has a neutral effect on the greenhouse effect.

[10] For Landfill Regulation please refer to Appendix B-1

Figure 2-6: Carbon Cycle – Landfill example



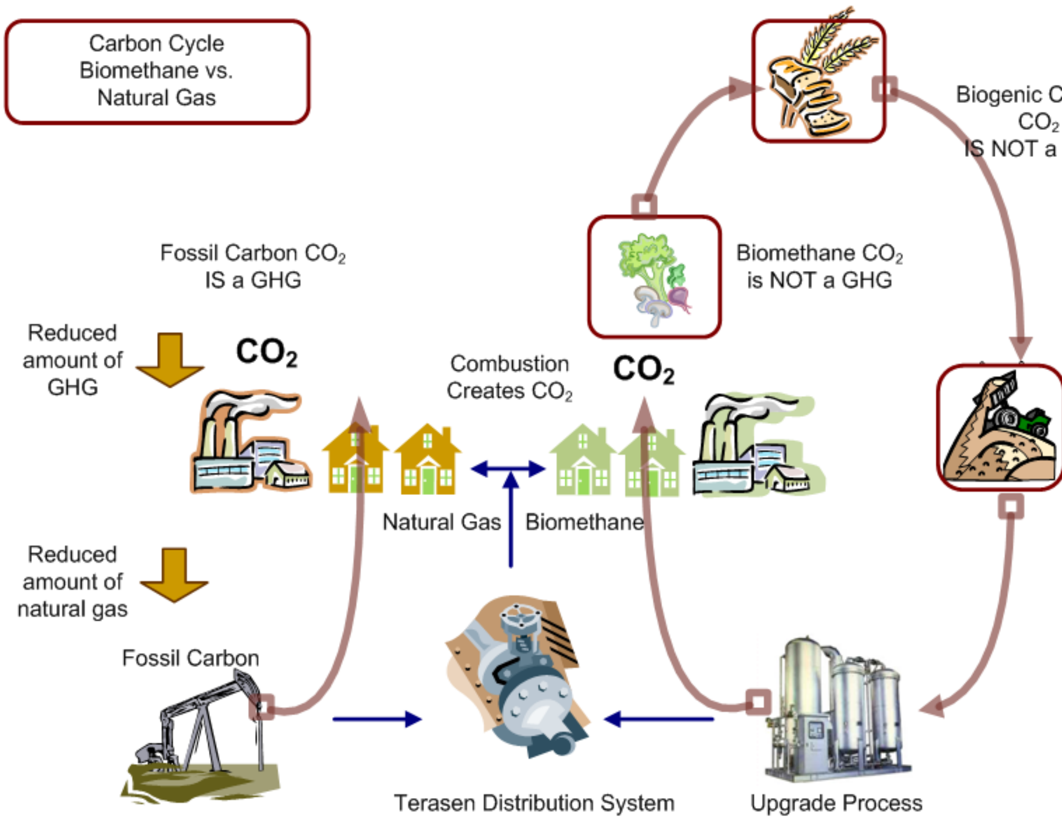
The carbon cycle is similar for other waste streams such as agricultural waste. Agricultural waste could either release methane directly into the atmosphere (if it is not carefully managed) or it can be aggregated in a digester. Once it is collected in a digester the agricultural waste would generate Biogas which could be used similarly for consumption in end uses.

2.7.3 DISPLACEMENT OF CARBON POSITIVE ENERGY SOURCE

Conventional natural gas and the CO_2 produced from its combustion are considered to be GHGs because they add to the total amount of CO_2 in circulation in the atmosphere. This occurs once natural gas is removed from an underground source (that which would not naturally end up in the atmosphere) and it is combusted. In addition, any methane released in the transportation process is considered to be GHG emission. By replacing conventional natural gas with Biomethane in end use applications, all else equal, there is a net reduction in the amount of GHGs in the atmosphere.

Figure 2-7 below helps to illustrate this point by showing Biomethane and natural gas side by side.

Figure 2-7: Carbon Cycle – Biomethane vs. Natural Gas



2.8 Conclusion

As discussed in this Section, Terasen Gas believes that Biomethane can serve as a practical, readily available fuel that is interchangeable with natural gas. The Company can take advantage of an existing natural gas distribution network to displace conventional natural gas. Biomethane is a renewable source of energy because it comes from organic waste streams. The production and consumption of Biomethane is carbon-neutral, and displacing natural gas with Biomethane will reduce GHG emissions.

3 GOVERNMENT POLICY AND ENERGY OBJECTIVES

3.1 Introduction

Federal, provincial, regional, and municipal governments are increasingly focused on addressing climate change and pollution. Governments at all levels are adopting policies in favour of renewable forms of energy as a key part of the solution to help achieve these goals. This Section discusses government's policy, objectives and direction at each level and discusses how Terasen Gas' Biomethane Application supports them.

3.2 Policy Objectives Advanced by Biogas Business Model (Supply Development through to Customer Offering)

The Provincial government has specific policies favouring the development of Biogas as a renewable energy source. Terasen Gas' proposals in this Application, which include proposals for constructing facilities to upgrade Biogas to Biomethane and inject it into the distribution system, an economic test for future supply, and a Green Gas offering, all advance government policies favouring the use of renewable energy sources, the efficient use of energy and reducing GHG emissions.

This Section of the Application discusses:

- The federal, provincial and municipal governments' policies on GHGs, utilization of renewable sources of energy, and energy efficiency;
- Specific policies in relation to Biogas; and
- How this Application advances those policy objectives.

3.3 Government Policy on Greenhouse Gas Emissions, Utilization of Renewable Energy and Energy Efficiency

All levels of government have developed policies favouring the efficient use of energy and the use of renewable energy as a means of reducing GHG emissions. This section focuses on the Provincial government's policies, and concludes with a brief discussion of Federal and municipal policies that largely echo BC's policies.

3.3.1 PROVINCIAL ENERGY POLICY

The framework for provincial energy policy is the 2007 BC Energy Plan.[11] The policies set out in the 2007 BC Energy Plan have been given effect in several pieces of legislation, including the recently passed Clean Energy Act (CEA)[12].

[11] "Energy Plan 2007: A Vision for Clean Energy Leadership". A copy is included in Appendix B-2

The 2007 BC Energy Plan built on the 2002 Energy Plan,[13] which had focused on low electricity rates, energy security, private sector involvement in new electricity development, and environmental responsibility. The 2007 BC Energy Plan committed British Columbia to addressing climate change by harnessing clean and renewable energy to reduce overall GHG emissions, and to a renewed focus on the efficient use of energy sources. Recently, the provincial government's commitment to reducing GHG emissions and increasing the development of clean energy were re-affirmed in the February 9th, 2010 Speech from the Throne and through the passing of the *Clean Energy Act*.

The Provincial Government has given effect to policies set out in the 2007 BC Energy Plan in legislation:

- Renewable Portfolio Standards are requirements that any given supply, or portfolio, of a fuel must be composed of a standard minimum amount of fuel from a sustainable source. An example of the adoption of a Renewable Portfolio Standard by the British Columbia Provincial Government was the 2008 introduction of the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act*.[14] This act created the legal structure required to impose an escalating minimum percentage of renewable fuel in gasoline and diesel sold within the province. As of January 1, 2010, the renewable component required is 5%, and the Carbon Tax applicable to gasoline and diesel has been reduced proportionately to reflect the reduced non-renewable component of these fuels.[15]
- The *Greenhouse Gas Reduction Targets Act* ("GGRTA"), enacted in 2007, mandates reductions of provincial GHG emissions of thirty-three percent by 2020 and eighty percent by 2050 using 2007 as the baseline.[16] The GGRTA also requires all departments of the provincial government to become GHG neutral by 2010.
- *The Carbon Tax Act,* passed in 2008, further signalled the provincial government's commitment to the reduction of GHG emissions.[17] As stated on the British Columbia Ministry of Finance website, the purpose of the carbon tax "is to ensure that a consistent long term price signal is provided to consumers so that they continue to make the choices required to reduce their fossil fuel use and emissions."[18]

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12 S.B.C. 2010, c. 22. A copy of the First Reading version of the *Clean Energy Act* is included in Appendix B-3. At the time of filing this Application this was the only version of the *Clean Energy Act* available on the Legislature's website.
13 "Energy Plan 2002: Energy For Our Future: A Plan for BC". See Appendix B-4
14 S.B.C. 2008, c. 16.
15 See Appendix B-5 for a copy of the Renewable Fuels Notice – Carbon Tax
16 S.B.C. 2007, c. 42.
17 S.B.C. 2008, c. 40.
18 British Columbia Ministry of Finance: Myths and Facts About The Carbon Tax (http://www.fin.gov.bc.ca/tbs/tp/climate/A6.htm)

- In 2008, the provincial government amended the *Utilities Commission Act* (the "Act" or the "UCA") to require the Commission to ensure that utilities undertake efficiency and conservation measures in their operations, and to consider the government's energy objectives in specified approval processes.[19] These objectives (pending the passage of Bill 17, the *Clean Energy Act*) include:

> (a) to encourage public utilities to reduce greenhouse gas emissions;
> (e) to encourage public utilities to use innovative energy technologies
>
> (ii) that support energy conservation or efficiency or the use of clean or renewable sources of energy;

On April 28th, 2010 the provincial government introduced Bill 17, the *Clean Energy Act*. The *Clean Energy Act* was given Royal Assent on June 3rd, 2010. Pursuant to section 58 of the *Clean Energy Act*, the "British Columbia's energy objectives" set out in section 2 of the *Clean Energy Act* replace the "government's energy objectives" currently specified in the UCA:[20]

> 58 Section 1 of the Utilities Commission Act, R.S.B.C. 1996, c. 473, is amended by repealing the definitions of "demand-side measure" and "government's energy objectives" and substituting the following:
>
> "British Columbia's energy objectives" has the same meaning as in section 1 (1) of the Clean Energy Act;

A number of the "British Columbia's energy objectives", quoted below, support this Application:[21]

> The following comprise British Columbia's energy objectives:
>
> (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% less than the level of those emissions in 2007,
>
> (ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

[19] Bill 15 – 2008, Utilities Commission Amendment Act, 2008.
[20] S.B.C. 2010, c. 22, section 58.
[21] As stated above, these are taken from the First Reading version of Bill 17 (which became the *Clean Energy Act*), which was the only available version at the time of filing this Application (see Appendix B-3).

(iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

(iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

(v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;

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

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

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

(k) to encourage economic development and the creation and retention of jobs;

(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;

(m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;

The *Clean Energy Act* places a new focus on clean bioenergy, laying the groundwork for development of this energy source in British Columbia. As the updated energy objectives will be applicable in the context of the regulation of public utilities, these amendments speak to the government's objective of involving public utilities in the targeted reduction of GHG emissions through the efficient development of clean and renewable energy, including biogas.

3.3.2 LOCAL GOVERNMENT POLICY

Local governments have responded to the provincial policy initiatives in respect of GHG reduction. On September 26, 2007, sixty-two communities across the province announced that they had signed on to the B.C. Climate Action Charter, committing to become carbon neutral by 2012.[22] By the end of 2009, 176 municipalities in B.C. (out of 188 in total) had signed the Climate Action Charter.

3.3.3 FEDERAL GOVERNMENT POLICY

While the 2005 and 2007 Climate Action Plans differed in their commitment to the Kyoto Treaty, they both showed the federal government's intention to reduce GHG's and provided similar

22 See Appendix B-6 for a copy of the news release announcing sixty-two communities' commitment to carbon neutrality

strategies for doing so. The federal government's commitment to reducing GHG emissions was re-stated in the March 3rd, 2010 Speech from the Throne.[23]

Terasen Gas is committed to adherence with government policies, and believes that the principles discussed above are in keeping with the Biogas and Biomethane developments proposed in this Application.

3.4 Specific Government Policy on Biogas

Finally, the Provincial Government has explicitly stated its support for Biogas project development in the 2008 Bioenergy Strategy. The Bioenergy Strategy states that "Government and its partners will collaborate to develop B.C. bioenergy projects utilizing energy from wood waste, agriculture, renewable fuels and municipal waste".[24] As noted previously, the CEA includes a "government energy objective" relating to biogas, and other "government energy objectives" (currently in the UCA and in the CEA) also support the upgrading of raw Biogas to Biomethane.

3.5 How this Application Delivers on Public Policy Direction

The proposals in this Application will promote the development and use of Biogas to help meet customer demand for energy. The development and use of Biogas as an energy source advances the policy objectives outlined above because of the following three attributes of Biogas and Biomethane discussed in Section 2 of this Application:

- Biogas is a renewable energy resource, and upgrading Biogas to produce Biomethane is the most efficient use of that renewable resource;
- the production and use of Biomethane is carbon neutral; and
- the use of Biomethane in place of a GHG-positive energy source (such as natural gas) results, all else equal, in a net reduction in GHGs.

In this Section, we draw a clear link between these attributes and government's energy objectives. We also discuss how the proposals in this Application will assist local governments.

3.5.1 GOVERNMENT'S ENERGY OBJECTIVES

Table 3-1 below identifies the relevant energy objectives that will now apply pursuant to the *Clean Energy Act*. The right hand column explains, in summary form, why the proposals in this Application are consistent with or promote "government's energy objectives".

[23] "A Stronger Canada. A Stronger Economy. Now and for the Future. Speech from the Throne to Open the Third Session of the Fortieth Parliament of Canada" March 3, 2010. Found at http://www.speech.gc.ca/grfx/docs/sft-ddt-2010_e.pdf

[24] BC Bioenergy Strategy – Growing our Natural Energy Advantage, 2008 (see Appendix B-7), p.8.

Table 3-1: How This Application Conforms to the Clean Energy Act

"Government Energy Objective"	**Reference to Clean Energy Act (CEA)**	**How Terasen Gas' Proposals Address "Government's Energy Objective"**
"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"	CEA s.2(d) (similar to current objective in section 2(e) of UCA)	Terasen Gas is proposing to create a market for Biomethane, a currently unused innovative source of clean and renewable energy in British Columbia. Further, the use of made-in-BC technology is proposed for one of the projects described in Section 8 of this Application.
"to reduce BC greenhouse gas emissions…"	CEA s.2(g) (similar to current objective in section 2(a) of UCA)	As detailed in Section 2.7.2 of this Application, the development and use of Biomethane is carbon neutral. The use of Biomethane in place of a carbon positive energy source, such as natural gas, will lead to reduced BC greenhouse gas emissions.
"to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia"	CEA s.2(h)	As detailed in Section 2.7.2 of this Application, the switching from conventional natural gas to Biomethane will lead to reduced BC greenhouse gas emissions.
"to encourage communities to reduce greenhouse gas emissions and use energy efficiently"	CEA s. 2(i)	As discussed immediately below and in Section 9, Terasen Gas proposes to partner with municipalities and regional districts to allow them to reduce their greenhouse gas emissions through the upgrading of their waste methane (Biogas) to pipeline quality Biomethane.
"to reduce waste by encouraging the use of waste heat, biogas and biomass"	CEA s. 2(j)	The upgrading of currently wasted Biogas to Biomethane, and its injection in to the Terasen Gas distribution system, will allow its use by customers on the Terasen Gas distribution system.
"to encourage economic development and the creation and retention of jobs"	CEA s. 2(k)	The Company is proposing to use made-in-BC technology for the Salmon Arm landfill project described in Section 8 of this Application. The Catalyst Power Inc. project proposed in Section 8 of this Application is directly creating the employment of the entrepreneurs who are responsible for the development of that project.
"to foster the development of first nation and rural communities through the use and development of clean or renewable resources"	CEA s. 2(l)	Terasen Gas proposes to partner with municipalities and regional districts, and will seek out further such partnerships that may also include First Nations communities for the development of clean and renewable Biomethane supply projects.

3.5.2 LOCAL GOVERNMENTS AND LANDFILLS

Many of the logical partners for Terasen Gas in the development of Biomethane projects are municipalities or regional districts. This is because landfills and sewage treatment facilities owned and/or operated by municipalities or regional districts are often excellent sources of raw Biogas. This Biogas presently represents a GHG emission liability for local governments due to their commitment to reduce GHG emissions. The capture of Biogas, and its upgrading to pipeline quality Biomethane, can help local governments generate revenue and meet the municipal GHG emission targets through the beneficial use of waste methane rather than flaring it. An excellent example of this can be found in the description of the Columbia Shuswap Regional District landfill Biogas project in Section 9.2 of this Application.

Our relationships with municipalities and regional districts have led us to believe that local governments would prefer to work with large, experienced organizations such as Terasen Gas. Local governments, as a result of the nature of their mandate, are highly risk-averse organizations which have shown a preference for partnership with stable, experienced, transparent, and safety-oriented organizations such as Terasen Gas.

In many instances, Terasen Gas will be the only logical partner for the economic transportation of upgraded landfill gas, given that landfills are often located in less populated areas some distance away from potential purchasers. The breadth of TGI's distribution system will mean that the system is proximate to populated areas (markets) as well as many sources of biogas.

3.6 Conclusion

The government policies in jurisdictions in which Terasen Gas operates have evolved, with a strong focus on the use of renewable energy, energy efficiency, and reduction of GHG emissions. The proposals in this Application will support government policy by promoting the supply and upgrading of Biogas, and by providing our customers with access to a Green Gas product.

4 GREEN PRICING

4.1 Introduction

The term "green pricing" is used in reference to utility programs in which utility customers pay a premium to have a portion of their energy come from a renewable energy source. The utility uses these funds to invest in renewable energy development or purchase carbon offsets on behalf of their customers to offset GHG emissions associated with their energy use. In recent years, a number of different models have been developed by public utilities in Canada and the U.S. to deliver green products and pricing to customers. In this Section, Terasen Gas provides an overview of the types of voluntary[25] green business models or programs that have been employed in North America, discusses participation rates in North American voluntary programs based on certain green pricing premiums, and reviews a few specific examples of green pricing programs in North America. This discussion provides the context and background for the Company's proposed demand-side business model contained within this Application.

4.2 Three Types of Voluntary Green Pricing Programs

There are three main types of programs that are being offered in the voluntary renewable energy market: contribution programs, energy-based programs, and offset programs. Terasen Gas is proposing a renewable energy-based program for its Green Gas offering, for reasons described in later Sections of this Application.

- **Contribution Programs:** The earliest types of programs were contribution programs that were designed to allow customers to contribute to a utility managed fund for renewable energy project development. In most contribution programs, customers can determine the amount of their monthly donation. In some cases the customer contribution is tax deductible, which utilities accomplish by setting up separate non-profit entities to administer the program.

- **Energy-based Programs:** The second and most successful are the energy-based programs. This type of program allows customers to choose a selected amount of energy to be supplied from renewable sources for a premium. Typically green pricing programs are structured so that customers can either purchase green power for a

[25] Green pricing programs generally fall under one of two general headings: voluntary programs and forced renewable portfolio programs. In general terms, voluntary programs are green pricing offerings that customers can elect to participate in, usually for a premium that is added to their bill. In contrast, forced renewable portfolio programs are programs that utilities are required to implement pursuant to legislation, which typically requires the utility to include a certain percentage of renewable energy within their power generation mix (such as BC Hydro). Terasen Gas focuses on a discussion of voluntary programs, as this application is not being made pursuant to a forced renewable portfolio program.

certain percentage of their energy use (often called “percent-of-use products”) or in discrete amounts or blocks at a fixed price (“block products”), such as a 100 kWh block of electricity.

- **Carbon Offset Programs:** The third and newest type of offering is a carbon offset program. This type of program offers customers the option to offset their GHG emissions for the energy use in their homes or business. The utility either acquires carbon offsets from their own projects or contracts with a third party to acquire carbon offsets on their behalf. Most utilities have criteria around which types offsets will be purchased, such as Biogas projects, wind projects, and/or solar projects within their jurisdiction or service territory.

The Company’s primary research as discussed in Section 5 showed a preference among customers for a renewable energy-based program offering as opposed to a carbon offset program. As discussed further in Section 5.3.2, the Company did not pursue investigation of a contribution program as this was the earliest type of program in other jurisdictions and is now the least popular of the more than 850 U.S. green pricing programs. As a result of its primary and secondary research, Terasen Gas is proposing a renewable energy-based program for its Green Gas offering.

4.3 Participation Rates in Green Pricing Programs

The National Renewable Energy Laboratory (NREL)[26] reports that the top ten green pricing program participation rates in 2008 were between 5% and 21% and are all some form of renewable energy-based program. The average customer participation rate in 2008 among all green pricing programs was 2.2%, and the median participation rate was 1.2%.[27] Despite the economic downturn of 2008-2009, NREL reported a long-term upward trend in consumer demand for renewable energy. More than 95%[28] of participants in green pricing programs have been residential customers, whereas over 75%[29] of the volume sales have been to the non-residential market.

Offset programs haven’t yet gained much acceptance and are reporting below average participation rates (between 0.25% – 1.2%).[30] This may be the result of offset programs being newer, less-established programs in the early days of marketing. As well, the offset market is

[26] The National Renewable Energy Laboratory (NREL) is the national laboratory of the US Department of Energy, Office of Energy Efficiency & Renewable Energy and is dedicated to the research, development, commercialization and deployment of renewable energy and energy efficiency technologies.
[27] NREL, Green Power: Marketing in the United States: A Status Report (2008 Data), (see Appendix C-1), Page11
[28] Ibid
[29] Ibid, Page 4
[30] eSource Member Inquiry, Nov 9, 2009. NREL, PG&E, SMUD, NW Natural

still an emerging market. Terasen Gas' Customer Demand survey, discussed in Section 5 of this Application, would also appear to suggest that there may be a lack of public awareness and knowledge with respect to offsets generally.

The statistics from NREL are summarized in Table 4-1 below.

Table 4-1: Customer Participation Rates in Utility Green Pricing Programs, 2002-2008

	2002	2003	2004	2005	2006	2007	2008
Average	1.20%	1.20%	1.30%	1.50%	1.80%	2.00%	2.20%
Median	0.80%	0.90%	1.00%	1.00%	1.00%	1.30%	1.20%
Top 10 Programs	3.0% - 5.8%	3.9%- 11.1%	3.8% - 14.5%	4.6% - 13.6%	5.1% - 16.9%	5.2% - 20.4%	5.0% - 21.0%

Source: NREL - Green Power Marketing in the United States: A Status Report (2008 Data)

At the end of 2008, the average industry participation rates have shown a slight trend upwards and the top-performing programs continue to show even greater improvement compared to 2002.

4.4 Green Price Premiums

Voluntary programs typically involve customers paying a green price premium. The average premium for renewable power in 2008 was 18% above conventional energy sources. As programs allow for a portion of the customer's energy to come from renewable sources, the average premium paid on a monthly basis for residential customers is around \$5-6 / month[31] (approximately a 10% premium assuming an average monthly usage of 600 kwh / month @ \$0.10 kwh national average). This is illustrated in Table 4-2 below.

Table 4-2: Residential Price Premiums of Utility Green Power Products 2001 - 2008 (¢/kwh - USD)

	2001	2002	2003	2004	2005	2006	2007	2008
Average Premium (Cents per kWh)	2.93	2.82	2.62	2.45	2.36	2.12	1.85	1.8
Median Premium (Cents per kWh)	2.5	2.5	2	2	2	1.78	1.5	1.5
US Average Price (Cents per kWh)	7.29	7.2	7.44	7.61	8.14	8.9	9.13	9.82
Average % Premium	40%	39%	35%	32%	29%	24%	20%	18%
Median % Premium	34%	35%	27%	26%	25%	20%	16%	15%

Source: NREL - Green Power Marketing in the United States: A Status Report (2008 Data)
http://www.eia.doe.gov/cneaf/electricity/epm/table5_6_b.html

31 NREL, Trends in Utility Pricing Programs (2006)

Since 2000, the average premium has dropped at an average annual rate of 8%, leading to lower initial premiums for many new programs[32]. Terasen Gas' proposed price premium will also follow this trend as discussed in Section 5.3.3.2 and will be in the range of 8-12% premium on the natural gas commodity.

4.5 Voluntary Green Pricing Program Examples

In this section Terasen Gas provides examples of how utilities price and structure their voluntary programs.

4.5.1 CONTRIBUTION PROGRAMS

Seattle City Light, the electric utility serving downtown Seattle, has several options to increase the supply of renewable energy including a contribution program to support renewable energy demonstrations, including local solar electricity projects, through City Light's Green Power program. The Green Power Program funds local renewable energy demonstration projects. These projects create awareness of renewable energy within the community, and help grow the local market for solar and other green technologies. A portion of funds support education and training programs for teachers, students, and the general public. Customers can chose their monthly contribution amount starting at $3.00 / month. Seattle City Light has just over 10,000 customers enrolled in this program.[33]

Three Minnesota municipal utilities—Austin Utilities, Owatonna Public Utilities, and Rochester Public Utilities—have programs through which customers can support the development of local solar photovoltaic (PV) systems. Under the SolarChoice program, residential and business customers can contribute through their monthly electric bill to a fund that will provide annual incentive payments to utility customers with PV systems, with 100% of the revenues going to these "SolarChoice producers." The incentive payment that a producer receives is proportional to the electricity that it generates.[34]

4.5.2 CARBON OFFSET PROGRAMS

Northwest Natural Gas ("NW Natural"), a natural gas utility serving Oregon and southwest Washington, launched a carbon offset product, Smart Energy, in September 2007. The utility offers customers the option to offset the GHG emissions from natural gas use in their home or business. Residential customers can choose to pay a fixed amount, about $6 / month based on the average home or they can pay about $0.10 / therm to offset their actual usage. Business

[32] NREL, Green Power: Marketing in the United States: A Status Report (2008 Data), (see Appendix C-1), pg 8
[33] Seattle City Light, http://www.ci.seattle.wa.us/light/Green/greenPower/greenpow.asp
[34] US Department of Energy, http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=2&companyid=452

customers can choose to offset 100% of their emissions for a 1 year commitment or pay a fixed rate per month with a minimum charge of $10 to offset part of their emissions. As of November 2009, this utility had about 8,000 customers enrolled in Smart Energy. Through the Smart Energy program, NW Natural and The Climate Trust invest in carbon offset projects that are most compatible with NW Natural's natural gas distribution business including investments in Biogas development. NW Natural has recently partnered with the Bonneville Environmental foundation and Three Mile Canyon Farms to build a digester. The project will utilize waste from 1,200 cows on the farm to produce Biogas.[35]

Pacific Gas and Electric ("PG&E") launched Climate Smart in June 2007, and it was the first utility to administer its own program and bid for offset projects entirely in-house. On March 4, 2008, PG&E and BioEnergy Solutions announced that their Biogas-to-pipeline injection project in Fresno County has begun production of renewable natural gas derived from animal waste.[36]

PG&E has more than 30,000 customers enrolled in ClimateSmart. This is a voluntary program in which customers can choose to pay a surcharge on their monthly bill in order to make their energy use GHG neutral. The cost is based on usage - PG&E charges approximately a quarter of a cent per kilowatt-hour and $0.065 / therm.

4.5.3 RENEWABLE ENERGY-BASED PROGRAMS

The Tennessee Valley Authority offers a program called Green Power Switch through participating distributors in its service territory[37]. Its program sources energy from solar, wind and Biogas and is sold to residential and commercial customers in 150 – kWh blocks (about 12% of a typical household's monthly energy use). Each block adds $4 to the customer's monthly power bills. Green Power Switch is also marketed to commercial and industrial consumers, who are asked to buy blocks based on the amount of energy they use.

Central Vermont Public Service offers customers the opportunity to enrol in "Cow Power". Customers who sign up pay an extra $0.04 / kWh. The web site states that there are currently six Cow Power farms located all across Vermont. Each farm has over 500 cows which produce (or are expected to produce) between 0.78 and 3.5 million kWh of electricity a year.

4.6 Other Green Pricing and Green Gas Programs in North America

Interest in green pricing programs continues to grow and it is important to understand what is happening in other jurisdictions in order to effectively position a Green Gas offering.

[35] NW Natural, http://www.smartenergynw.com/about/
[36] PG&E, http://www.pge.com/climatesmart/
[37] The Tennessee Valley Authority (TVA) is an electricity generator and transmitter in Tennessee and portions of six neighbouring states. Most of TVA's electricity is sold to municipal electric distributors and cooperatives, with smaller portions being sold directly to large industrial customers and in regional electricity markets.

Several Canadian utilities started offering green power programs in 2002 such as SaskPower, Maritime Electric, and Nova Scotia Power. These programs have since been closed to new customers as they are either fully subscribed or now have renewable electricity requirements as part of their portfolio. New Biogas projects and green energy programs in Canada include:

- Investment by Toronto Hydro to generate up to 10 MW of electrical power using Biogas from a wastewater treatment plant.
- In September 2009, the Ontario government permitted Enbridge Gas Distribution Inc. ("Enbridge") and Union Gas Limited to own and operate renewable energy-based projects including stationary fuel cells, wind, water, biomass, Biogas, solar and geothermal energy generation facilities up to 10 megawatts in capacity. As a result, Enbridge is currently pursuing regulatory approval to invest in Biogas projects and offer a green pricing program.
- Bullfrog Power is an alternative electricity provider that provides a green pricing program for renewable electricity (wind and low-impact hydropower) to customers in British Columbia, Alberta, Ontario, Nova Scotia, New Brunswick and Prince Edward Island.
- Enmax Energy ("Enmax") in Alberta offers customers the option to redeem "EasyMax rewards" dollars to support renewable electricity in the province. Enmax customers are eligible for EasyMax rewards when they choose to purchase both gas and electricity from Enmax.

Utility green pricing programs in the US have grown significantly over the past decade. A 2007 Chartwell report indicated that 58% of utilities surveyed had some kind of green pricing program.[38] The National Renewable Energy Laboratory (NREL) reports that more than 850 utilities in the US have some sort of green pricing program.[39] The vast majority of programs offered are for renewable electricity programs, however, gas utilities are now entering the arena as a way to respond to consumer demand to reduce their carbon footprint.

4.7 Conclusion

The development of renewable energy is more advanced in the electricity industry in BC than it is in the natural gas industry, both in terms of the quantity of supply developed and in terms of the business models and contractual arrangements supporting the industry. The heavy policy focus in BC on developing renewable electricity resources combined with the existing extensive hydro-based Heritage electricity resources create the public impression that BC electricity is the "green" and environmentally-preferred energy source. In these circumstances it is becoming more difficult for natural gas to compete on an environmental basis. Terasen Gas believes that offering a renewable energy product will help meet customer demand for environmentally friendly options. Further, it will help to establish a path forward for complying with any future

[38] Chartwell, Helping Customers Live a Sustainable Lifestyle, May 2007 (see Appendix C-2)
[39] NREL, Green Power: Marketing in the United States: A Status Report (2008 Data), (see Appendix C-1)

mandatory requirements for including renewables in a utility's energy mix, if and when Renewable Portfolio Standard may be established for natural gas utilities in BC. Terasen Gas has concluded that, among the three voluntary green pricing models in use in North America, a renewable energy-based program is appropriate for its customers at this time.

5 DEMAND IN BRITISH COLUMBIA

5.1 Introduction

Terasen Gas commissioned TNS Canadian Facts ("TNS"), one of Canada's largest marketing and social research firms, to conduct a primary market research study[40] to validate and evaluate the potential residential and commercial markets for a Biogas[41] program in BC, its market drivers, and factors affecting different price points.[42] There was strong support from both residential and commercial markets surveyed for a Terasen Gas renewable energy-based program, in which customers can sign up for a portion of their gas use to come from the Company's proposed Biogas supply projects. There was also a strong preference among survey participants for a 10% premium to the commodity price, which would result in a 10% blend of Biogas. Terasen Gas has, to a significant extent, designed the proposed program around the results of the market research.

In this Section, Terasen Gas reviews:

A) The Study[43] methodology;

B) The key findings of the Study; and

C) Terasen Gas' conclusions based on the Study findings.

5.2 Study Methodology

The Study focused on BC residential households and Terasen Gas commercial customers. A quantitative research methodology was used for both market segments. Similar questionnaires were developed for residential and commercial segments to ensure findings were comparable. Copies of the questionnaires developed for the Study are attached in Appendix D-2.

The residential survey consisted of a total of 1,401 online surveys completed between November 23 and December 4, 2009 among BC residents (18 years of age or older) using TNS Canadian Facts' online panel. TNS online panels are comprised of individuals who volunteer to complete surveys from time to time. This type of polling is common industry practice.

40 Refer to Appendix D-1, TNS Canadian Facts is one of Canada's largest marketing and social research firms. TNS was established as Canadian Facts in 1932 as the country's first survey research organization. Today, they have offices in Toronto, Montreal, Ottawa and Vancouver, with 170 full-time members of staff.

41 The terminology "Biogas" was used in the TNS Survey as attached in Appendix D-2 to refer to both Biogas projects and a green gas program in order to keep the survey simple. This section of the Application has adopted that usage in order to be consistent with the language of the survey.

42 Terasen Gas also notes that there is a substantial body of secondary literature that indicates that there is consumer demand for renewable energy-based programs. This is discussed further in Section 4.

43 TNS conducted two surveys, one for each of the residential and commercial markets (together referred to as the "Study"), between November 2009 and January 2010.

Three different types of residential households were sampled:[44]

- Terasen Gas customers (those who receive a gas bill directly from Terasen Gas - 799 interviews);
- Indirect customers (gas users who are not billed directly i.e. gas costs are included in strata fees or rent - 200 interviews); and
- Non-gas users (those who do not use gas - 50 interviews).

The margin of error on 1,401 interviews is +/- 2.6% (at 95% confidence level).[45]

The commercial survey consisted of a total of 500 online surveys conducted with commercial customers of Terasen Gas. The surveys were conducted between December 14, 2009 and January 22, 2010. The margin of error on 500 interviews is +/- 4.4% (at 95% confidence level).

A business sample of over 26,000 customers was provided directly by Terasen Gas to TNS for the commercial survey as TNS does not currently have a commercial online panel. Commercial customers were contacted initially by telephone and those which chose to participate were then emailed a link to the online survey.

The Study design addressed the fact that, in assessing how respondents rate the relative importance of various energy initiatives or program features, survey respondents are likely to rank many of the proposed features presented to them as important. In other words, if a feature is important enough for Terasen Gas to include in a survey, it is very likely that respondents will also find it to be important to them. If everything is reported to be important, it becomes difficult to understand what actions should be taken. The Discrete Choice Model ("DCM") employed in evaluating the survey results indirectly measured which features weigh more heavily in the respondents energy choices.[46] An online methodology was used in order to facilitate a discrete choice analysis, as online surveying can be designed to take into consideration multiple elements associated with an energy initiative program that cannot be done on the telephone or by mail back.

[44] Refer to Appendix D-3; TNS Biogas Market Summary, pg 3-4

[45] Ibid, pg 18. Note: margin of error for the study is a guide because the sample is a panel and not a randomly selected sample

[46] A Discrete Choice Model (DCM) asks respondents to choose between a series of program alternatives that trade-off on different features. From their choices, a DCM model is able to indirectly measure which elements weighed more heavily on a respondent's selections. In this study, a model was built on three dimensions – (1) type of energy initiative, (2) percent reduction in GHG levels, and (3) effect on monthly gas bill. Thirty-six possible pairings of choice sets were built into the questionnaire, based on different permutations of the three dimensions. Each respondent was presented with a random set of 16 pairings and asked to select the scenario they preferred in each pairing.

5.3 Key Findings of the Study

The Company's key findings from the Study are as follows:

A) There is strong residential and commercial support of Terasen Gas' investment in Biogas projects and offering a Biogas program.

B) Both residential and commercial markets have a strong preference for a renewable energy-based program such as Biogas rather than a carbon offset program.

C) There is strong support for low percentage increases on the current commodity price across the board for all customers (between 0.5 – 3%), should the cost of a Biogas program be borne by all customers.

D) There is a strong preference for a 10% price premium on the commodity for a 10% blend of Biogas and associated GHG reductions.

E) The residential market indicates a slightly higher participation level potential than the commercial market. For a voluntary program, 16% of residential respondents and 10% of commercial respondents indicated they would enrol in a Biogas program at a 10% increase to their current commodity price.

In the remainder of Section 5.3, Terasen Gas reviews these key findings from the Study. Additional detailed findings can be found in the TNS Biogas Market Summary (see Appendix D-3).

5.3.1 OPINIONS ON TERASEN GAS DEVELOPING BIOGAS SUPPLY AND A BIOGAS PROGRAM

Key Finding: *There is strong residential and commercial support of Terasen Gas' investment in Biogas projects and offering a Biogas program.*

The Study demonstrates that the level of support among residential and commercial respondents for a Biogas product offering is strong. Approximately 67% of respondents indicated they agree with Terasen Gas developing and investing in Biogas projects.[47] A similar number agree with Terasen Gas offering a Biogas program to customers. This is reflected in Figure 5-1 below. The applicable survey questions are quoted in footnotes.

[47] Refer to Appendix D-3; TNS Biogas Market Summary, pg 8 & pg 12

Figure 5-1: Strong Residential & Commercial Support for Terasen Gas Investment in Biogas Projects and a Biogas Program

Residential Results:

Should Terasen Gas Be Investing in Biogas [48]

	Total
Base: Total respondents	(1,401)
Yes (8-10)	67%
Maybe (4-7)	27%
No (1-3)	2%
Decline	4%

Should Terasen Gas Offer A Biogas Program[49]

	Total
Base: Total respondents	(1,401)
Yes (8-10)	65%
Maybe (4-7)	30%
No (1-3)	1%
Decline	4%

Commercial Results:

Should Terasen Gas Be Investing in Biogas[50]

	Total
Base: Total respondents	(500)
Yes (8-10)	67%
Maybe (4-7)	23%
No (1-3)	3%
Decline	7%

Should Terasen Gas Offer A Biogas Program[51]

	Total
Base: Total respondents	(500)
Yes (8-10)	71%
Maybe (4-7)	22%
No (1-3)	2%
Decline	5%

This strong survey support confirms the Company's current direction for developing Biogas supply projects and a Biogas offering as an appropriate means to address environmental issues for its customers.

5.3.2 OPINIONS ON TYPES OF PROGRAMS

Key Finding: *Both residential and commercial markets have a strong preference for a renewable energy-based program such as Biogas rather than a carbon offset program.*

48 Question asked: Do you think Terasen Gas should be investing in Biogas projects?
49 Question asked: Do you think Terasen Gas should invest in offering a Biogas program to residential customers?
50 Question asked: Does your organization support Terasen Gas investing in Biogas projects?
51 Question asked: Do you think Terasen Gas should invest in offering a Biogas program to its commercial customers?

Two different types of Green Gas programs were presented to survey participants:

- a renewable energy-based (Biogas) program, where customers can sign up for a portion of their natural gas use to come from Biogas; and
- a carbon offset program, where customers can sign up for the utility to purchase carbon offsets from Terasen Gas' Biogas projects as well other projects on their behalf to offset their emissions from their use of natural gas in their home or business.[52]

The Company chose not to ask respondents about a contribution type program, where customers can make a donation to support renewable energy-based projects, as this type of program was the earliest type of green pricing program and is now the least popular. Among the more than 850 U.S. green pricing programs, only about 15-20 call themselves "contribution" programs.[53]

In order to determine if respondents supported the concept of Terasen Gas proceeding with a carbon offset program, it was first necessary to understand the current level of awareness of carbon offsets. Respondents were asked of their awareness of carbon offset programs and the likelihood of purchasing carbon offsets.[54] Only 50% of residents were aware of carbon offsets and 31% said they are very likely to purchase a carbon offset.[55] Commercial customers had a higher awareness of carbon offsets at 66%. Despite higher awareness levels, just 24% indicated a likelihood of purchasing them to offset their business' natural gas use.[56]

Participants were then provided with a description of the different Green Gas program options as described above and were further asked which of the two programs - a Biogas program or a carbon offset program - they would be more inclined to choose[57]. The respondents preferred a Biogas program over a carbon offset program by a factor of approximately three-to-one for both customer groups. When asked if they would actually enrol in a program (assuming all factors remained equal, i.e. energy prices)[58], 56% of residential respondents and 47% of commercial respondents indicated they would sign up for a Biogas program. Only 24% of residential respondents and 35% of commercial respondents indicated they would sign up for a carbon

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52 These two types of programs are discussed in greater detail in Section 4.

53 Refer to Appendix C-1 NREL, Green Power: Marketing in the United States: A Status Report (2008 Data), Page 25

54 Questions asked: Have you heard of the term carbon offset? Yes /No. How likely would you be to purchase a carbon offset for your natural gas use in order to reduce your environmental footprint? (Scale 1-10)

55 Refer to Appendix D-3; TNS Biogas Market Summary, pg 8

56 Ibid, pg 13

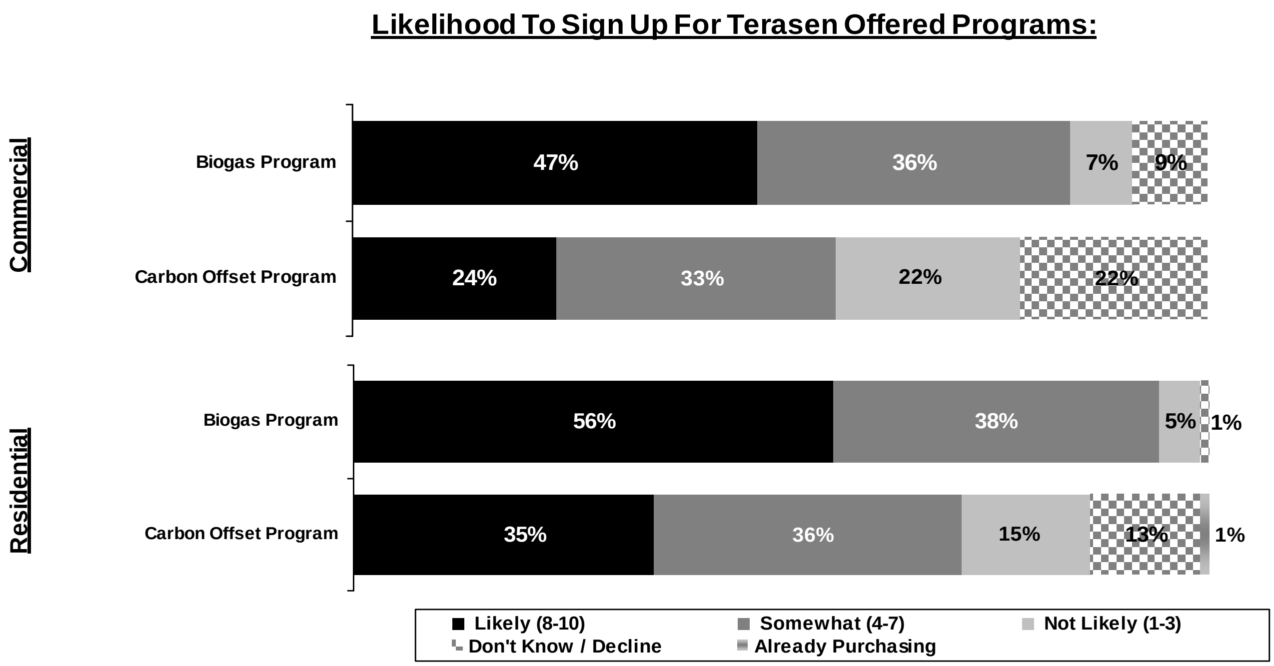
57 Question asked: Which of these two programs would you be more inclined to see Terasen Gas introduce, if it were to do so? A) an offset program b) renewable energy program c) neither d) don't know

58 Question asked: (On a scale of 1 – Not very likely to 10 – Very likely) All things being equal, if Terasen Gas offered a biogas program, how likely would you be to sign up?

offset program. The strongest motivators for signing up for a Biogas program were preserving nature, providing for future generations and doing the "right thing".[59]

Figure 5-2 depicts the likelihood of customers to sign up for a Terasen Gas Biogas program or carbon offset program.

Figure 5-2: Biogas Program is Preferred over Carbon Offset Program



The key finding of this part of the Study is that both residential and commercial segments confirmed at different points in the Study that they prefer, and are more likely to sign up for, a renewable energy-based program such as Biogas than for a carbon offset program. This result, coupled with the lower participation rates experienced by existing carbon offset programs in the US (0.25% - 1.2% vs. 2.2% national average[60]), and residential and commercial respondents indicating a strong preference for a Biogas program, provides support for Terasen Gas positioning its initial Green Gas offering as a renewable energy-based (Biogas) program. However, as discussed in Section 10.7.3, carbon offsets may be used as a GHG balancing mechanism in the event of a shortfall of Biogas supply in a given time period.

59 Refer to Appendix D-3; TNS Biogas Market Summary, pg 9 and pg 13
60 Refer to Appendix C-1: NREL, Green Power: Marketing in the United States: A Status Report (2008 Data), Page11 and eSource Member Inquiry, Nov 9, 2009. NREL, PG&E, SMUD, NW Natural

5.3.3 DETERMINING PRICING POINTS FOR A BIOGAS PROGRAM

5.3.3.1 Universal Price Increase

Key Finding: *There is strong Terasen Gas customer support for low percentage increases on the current commodity price across the board for all customers (between 0.5 – 3%), should the cost of a Biogas program be borne by all customers.*

Residential and commercial respondents who indicated they were likely to sign up for a Biogas program were asked whether they would prefer to have a Terasen Gas Biogas program funded through a universal price increase borne by all consumers or through price premiums charged to only those who sign up[61]. The results were that 47% would prefer a universal price increase, while 26% prefer a premium price increase. However, a large number of residents (27%) did not state a preference or did not know how to answer this question[62].

The majority of commercial organizations that indicated a likelihood to sign up for a Biogas program (60%) indicated a preference to have a Terasen Gas Biogas program funded through a universal price increase borne by all customers. One in five preferred a price premium charged to only those who sign up and a similar number are unsure of which option to choose.[63]

The Study sought to gauge what moderate price level increases customers would be willing to support if costs were to be borne by all customers. All respondents were asked through a direct line of questioning whether or not they would support a Terasen Gas Biogas program if all customers had to pay an X% increase in the current commodity price of natural gas[64]. Four different price increases were explored[65]:

- 3% more than their current commodity price;
- 2% to 3% more;

61 Question asked: The cost for a Biogas program can be offered to consumers in one of two ways. Which way would you prefer to see Terasen offer this program, if it were to do so? A) Terasen Gas offers a program that its customers can sign up for. Those who sign up would pay a premium for biogas. B) The increase in cost for biogas supply would be borne by all Terasen Gas customers. C) Don't know.

62 Refer to Appendix D-3; TNS Biogas Market Summary, pg 9

63 Ibid, pg 13

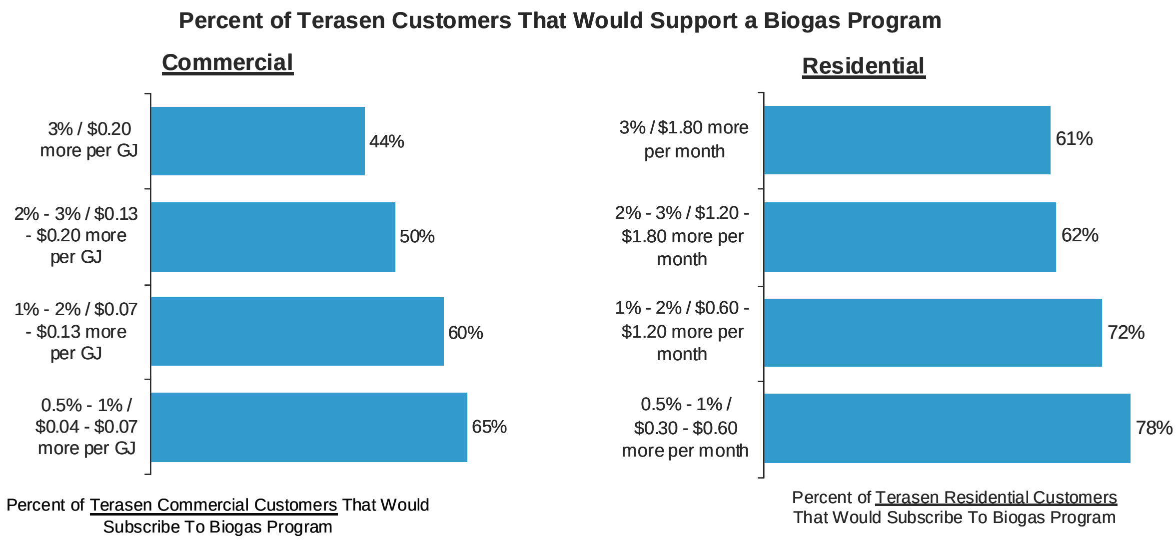
64 Questions asked: If the cost of biogas is borne by all customers and you had to pay X% more than the current commodity price of natural gas – would you support such as Biogas program.

65 Note: A price per GJ estimate was provided to commercial customers and a monthly bill estimate to residential customers in order for the respondent to further understand the order of magnitude of the affect on their bill. Pricing was based on the 5 year Sumas Forward price as of October 2009 of $6.88 and monthly charge estimate for residential use based on 100 GJ / yr. (refer to Appendix D-3; TNS Biogas Market Summary, pg 9 & pg 13)

- 1% to 2% more; and
- 0.5% to 1% more.

There was a very high level of support at a 0.5% - 1% price increase for costs to be borne by all customers for a Terasen Gas Biogas program. The results below pertain specifically to Terasen Gas customers and indicate that 78% of Terasen Gas residential customers and 65% of commercial customers would support the program[66] at this level of price increase. As expected, support for a Biogas program where costs were borne by all customers decreased as the potential price of gas increased. This is depicted in Figure 5-3 below.

Figure 5-3: Terasen Gas Customers Support Moderate Increases to All Customers for Biogas



While the results of this Study indicate that a large majority of customers would support moderate price increases for a Biogas program if the full cost of the program was borne by all customers, the Study also suggested that there is also enough market share potential for a program where customers voluntarily pay a “green premium” price[67]. Consistent with these findings, Terasen Gas has proposed a hybrid model that involves a Green Gas offering at a premium price, but with some of the program costs being borne by all customers as discussed in Section 10 (Costs, Allocation and Accounting Treatment, and Rate Setting) which will be well below a 0.5% price increase to the customers’ commodity.

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[66] Appendix D-3: TNS Biogas Market Summary, pg 9 & pg 13
[67] Green premium pricing is discussed in Section 4

5.3.3.2 Price Premiums for Voluntary Program

Key Finding: *Residential and commercial markets indicate a strong preference for a 10% price premium on the commodity for a 10% blend of Biogas and associated GHG reductions.*

The Study considered how much residential and commercial segments were willing to pay for a voluntary program taking into consideration higher price premiums. A voluntary program would mean that costs of acquiring the Biogas or carbon offsets and associated program costs would be paid by program participants.

The Discrete Choice Model (DCM) was employed to evaluate multiple considerations for the Company's Green Gas program. In this case the discrete choice exercise explored the relationship among[68]:

- The price of the renewable energy options of a Biogas program and carbon offset program;
- Measuring steeper price increases of 10%-30%; and
- GHG reductions.

These results confirmed that price is an important consideration, but that larger price increases can be counteracted by the prospect of disproportionately higher GHG reductions (e.g., 20% price increase yielding a 30% GHG reduction is as popular as an option that has a 10% cost increase and a 10% GHG reduction)[69].

As discussed in Section 5.3.2, Terasen Gas has decided to offer a renewable energy-based (Biogas) program as it is the preferred option at this time over a carbon offset program. Therefore, in order to determine potential market size potential for a renewable energy-based (Biogas) program, Terasen Gas further evaluated the customer preference for three pricing options assuming a price premium between 10%-30% which is the range of other green pricing premiums as discussed in Section 4. These assumptions leave the following three choices available to determine the potential market size at the time of the survey for a renewable energy-based program and associated GHG reduction potential:[70]

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[68] A Discrete Choice Model (DCM) asks respondents to choose between a series of program alternatives that trade-off on different features. From their choices, a DCM model is able to indirectly measure which elements weighed more heavily on a respondent's selections. In this study, a model was built on three dimensions – (1) type of energy initiative, (2) percent reduction in GHG levels, and (3) effect on monthly gas bill. Thirty-six possible pairings of choice sets were built into the questionnaire, based on different permutations of the three dimensions. Each respondent was presented with a random set of 16 pairings and asked to select the scenario they preferred in each pairing.

[69] Appendix D-3; TNS Biogas Market Summary, pg 10 & pg 14

[70] Survey assumed a 5 yr forward price of $6.88/ GJ vs. Biomethane at $13 / GJ

- Option 1 – a 10% price increase resulting in a 10% blend of Biogas and a 10% GHG reduction;
- Option 2 – a 20% price increase resulting in a 20% blend of Biogas and a 20% GHG reduction; and
- Option 3 – a 30% price increase resulting in a 30% blend of Biogas and a 30% GHG reduction.

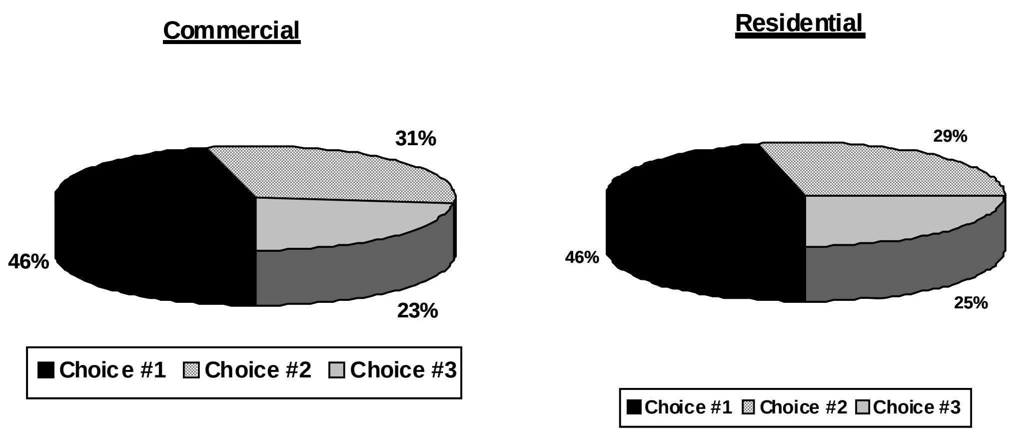
Of those that were likely to sign up for a program, almost half (46%) had a preference for Option 1, at a 10% price increase, with a 10% GHG reduction. Approximately 30% would choose Option 2 and 23-25% preferred Option 3.[71]

Figure 5-4: Customers Prefer a Renewable Energy-Based Program at a 10% Price Premium resulting in a 10% GHG Reduction

Choice #1
Renewable energy-based (Biogas) program
10% price increase
10% GHG reductions

Choice #2
Renewable energy-based (Biogas) program
20% price increase
20% GHG reductions

Choice #3
Renewable energy-based (Biogas) program
30% price increase
30% GHG reductions



Base: The 47% of Terasen commercial customers Who Are Likely To Sign Up For A Biogas Program (n=237)

Base: The 56% of Terasen customers who are likely to sign up for a biogas program (n=445)

As might be expected, price is a strong factor with respondents gravitating towards the lowest price options for a renewable energy-based (Biogas) program. Both price and reduced GHG emissions are both relatively important to customers, although the relative importance of reduced GHG emissions drops off as price goes up and proportionate increases in GHG reductions are not enough to offset increase in prices. The inter-relationship between price and GHG reduction factors shows a very similar pattern for commercial customers as it does for residential customers.

The strong preference for Option 1 suggested to Terasen Gas that it will achieve the highest level of success for customer sign-ups at a 10% price premium on the commodity for a 10% blend of Biogas and associated GHG reductions.

71 Appendix D-3; TNS Biogas Market Summary, pg 11 & pg 15

5.4 Market Potential for a Biogas Program

<u>Key Finding</u>: *The Residential market indicates a slightly higher participation level potential than the commercial market. For a voluntary program, 16% of residential respondents and 10% of commercial respondents indicated they would enrol in a Biogas program at a 10% increase to their current commodity price.*

Using the survey data, TNS calculated projected market estimates that indicated the best case estimates for sign-up to a Biogas program. The market projections are based on Terasen Gas customers who receive a gas bill directly from Terasen Gas as they would have the most control over whether or not they would sign up for a program. The market potential (best case) for price points of 10%, 20% and 30% increases is derived from the DCM analysis that indicates the share of preference at each of the price points for a renewable energy-based (Biogas) program, and the customers who are willing to support price universal price increases of at least 3% or more.

The following results were observed for these price points for residential customers:

- 16% of residents say they would sign up for a Biogas renewable energy-based program that had a 10% price increase and a corresponding 10% GHG reduction;
- 11% of residents say they would sign up for a program at a 20% price increase with a 20% GHG reduction; and
- 8% of residents say they would sign up at a 30% price increase with 30% GHG reduction.[72]

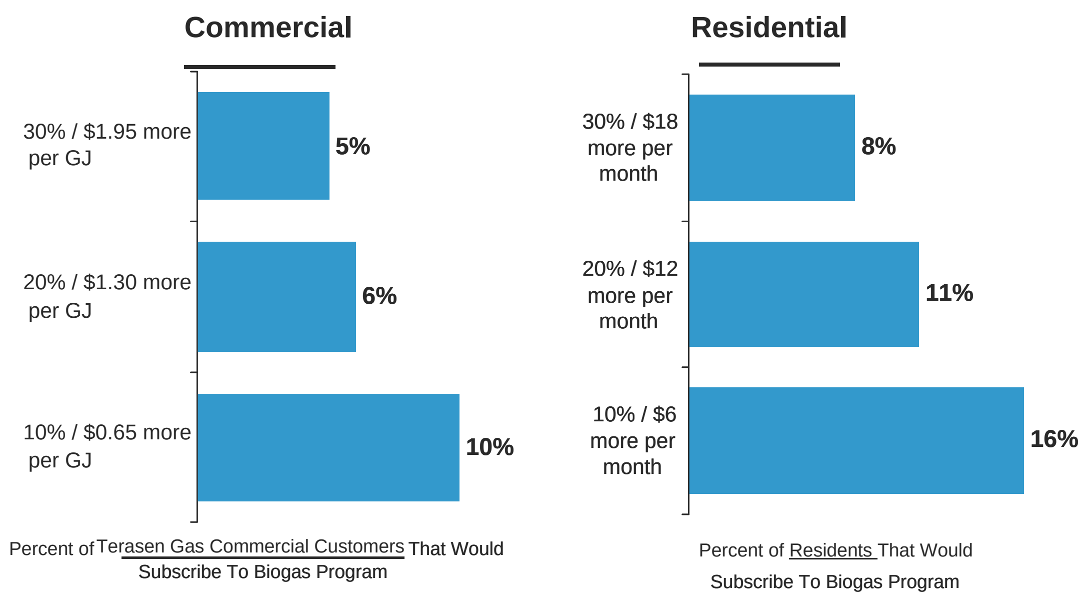
A smaller proportion of commercial customers surveyed say they would sign-up for a Biogas initiative at the higher price premiums. The results were:

- 10% of Terasen Gas' commercial customers say they would subscribe to a Biogas program at a 10% price increase of the current commodity price and 10% GHG reduction;
- 6% of commercial customers say they would subscribe at a 20% price increase and 20% GHG reduction; and
- 5% of customers say they would subscribe at a 30% price increase and 30% GHG reduction.[73]

These results are reflected in Figure 5-5 below.

[72] Appendix D-3; TNS Biogas Market Summary, pg 12
[73] Ibid, pg 15

Figure 5-5: Market Size Projections Based For a User Pay Program



**Above figures are based on share of preference (DCM analysis) with corresponding GHG reduction levels associated with each price point.*

The estimated market potential at a 10% price increase, calculated by extrapolating from the survey results as of December 2009, is 16% of Terasen Gas residential customers and 10% of commercial customers. This is equal to an estimated 120,000 residential customers[74] and 9,200 commercial customers[75]. These are quite high results when compared to the industry average for green pricing programs across the US is a participation rate of 2.2%[76] and the Company will use caution and conservatism when forecasting demand as discussed in Section 11.2.1.

Applying the industry average for enrolment in green pricing programs would result in over 16,000 residential sign-ups for Terasen Gas. Terasen Gas considers this to be a conservative measure because the industry average includes carbon offset programs, which tend to have lower participation rates than renewable energy-based programs which are the top performers and is in the nature of what is proposed by Terasen Gas. The two current supply projects included in this Application could currently only serve 12,000 –15,000 residential customers based on a 10% Biogas blend. Therefore, the Company feels confident that there is sufficient demand even when using the industry average to proceed with a Green Gas offering to customers.

[74] Calculated from 755,660 total Terasen Gas residential customers in BC as of December 2009.
[75] Calculated from 92,579 commercial customers as of December 2009.
[76] NREL, Green Power: Marketing in the United States: A Status Report (2008 Data) , Page11 (Appendix C-1)

5.5 Terasen Gas' Conclusions Regarding Program Design

The market research discussed above suggests that a majority of customers support Terasen Gas' involvement in developing Biogas supply resources and providing a renewable product offering. Terasen Gas considers that the results confirm the direction Terasen Gas is taking in developing Biogas supply and a Green Gas offering. Terasen Gas considered the results of the Study in structuring its Green Gas offering. In particular, the Study results suggested:

A) Terasen Gas should develop a renewable energy-based (Biogas) program and tariff offering whereby customers can sign up for a portion of their natural gas to come from Biogas. This type of program is preferred to offsets.

B) Customers perceive value for all gas customers from Terasen Gas' development of the Green Gas offering; therefore, a cost treatment that involves some costs associated with offering the renewable energy-based program being borne by all customers is appropriate.

C) Targeting residential customers in the initial rollout is reasonable, since residential customers indicate a higher participation potential and have greater certainty around use rates in order to better manage supply and demand imbalances. The Company will propose to expand the Green Gas offering to the commercial market once Biogas supply is further established and experience has been gained with the program in the residential market.

D) The initial offering will be for a 10% blend of Biogas as there is a larger preference for a 10% price premium at a 10% GHG reduction level relative to the 20% price premium / 20% GHG reduction or 30% price premium / 30% GHG reduction alternatives. The 10% blend will also allow Terasen Gas to maximize household involvement by reaching more customers with the available supply of Biogas relative to the other two options studied.

E) The offering may also be expanded to include additional blends of Biogas and to reach additional niche markets once Biogas supply is further established.

Aligning the program design with the quantitative research results provides the program with the best opportunity to flourish.

6 CUSTOMER OFFERING, PRODUCT ROLLOUT AND PROPOSED TARIFFS

6.1 Introduction

Terasen Gas has developed a Green Gas offering, which it proposes to phase-in starting October 1st, 2010. The proposed method to roll out the program to customers: is responsive to customer demand and expectations; is able to mirror business rules currently in place for Terasen Gas' existing Standard Rate offering; leverages existing systems and infrastructure; co-exists with the Company's current gas supply resources and the Essential Service Model ("ESM"); and allows for recovery of incremental costs from the appropriate groups of customers.

In this Section, Terasen Gas describes:

A) The guiding principles for the design of the Green Gas business model;

B) Key elements of Green Gas business model;

C) The phased rollout approach;

D) The projected demand for the Green Gas offering;

E) Terasen Gas' proposed customer education plan; and

F) Tariffs proposed in this Application.

6.2 Guiding Principles for the Design of the Green Gas Business Model

Terasen Gas developed Guiding Principles to assist with designing the Green Gas offering and the supporting business rules that are attached in Appendix E-1. The Guiding Principles were not evaluated against a formal weighting system; rather, they were used as a reference to ensure the selection of an appropriate model took into consideration various aspects of the Company's business.

The Green Gas Guiding Principles are:

A) The Green Gas offering should provide customers the opportunity to reduce their carbon footprint or carbon intensity.

B) The Green Gas offering should be compatible with the Essential Services Model, which underlies the Customer Choice Program.

C) The product offering should be simple to understand and easy to communicate to customers.

D) The Green Gas offering should be flexible in order to be adaptable to future market conditions.

E) The safety and reliability of the Terasen Gas delivery system should not be compromised.

F) Sufficient Biogas production infrastructure should be developed to ensure that a sufficient volume of Biomethane is available to meet customer demand.

G) The Green Gas offering should leverage existing systems and infrastructure set up in order to minimize system impacts and the need to incur incremental costs.

H) The structure of the program should ensure that appropriate costs associated with the development and acquisition of supply and ongoing O&M of the program are borne by Green Gas customers, while those costs incurred for the process and system enhancements, customer education and call center are borne by all customers.

I) For the benefit of the customers of Terasen Gas, the design of the Green Gas program should support the future attractiveness of natural gas as part of the solution of a low carbon energy future.

6.3 Key Elements of Proposed Green Gas Business Model

The Company proposes to phase-in the implementation of the Green Gas program over a multi-year period to ensure that the Green Gas product offering is effectively positioned for customer participation and to match the supply that is available. Key program features include:

- The Company proposes creating a new Biomethane tariff to allow eligible customers to either remain on the standard commodity rate (e.g., Terasen Gas Standard Rate) or to select the Terasen Gas Biomethane Tariff. The Biomethane Tariff will be a specific blend of Biomethane and conventional natural gas (for this Application, Terasen Gas proposes a blend of 10% Biomethane and 90% conventional natural gas). The Green Gas sales model selected by Terasen Gas as the basis for implementing the Green Gas program was determined to be the most suitable because it is able to mirror Terasen Gas' current Standard Rate offering, leverage existing systems and infrastructure in order to minimize system impacts and the need to incur incremental costs, and does not impact the Essential Service Model. The price of the new tariff will be at a premium, compared with the standard commodity rate from Terasen Gas. Discussion regarding alternative business models considered can be found in Appendix E-2.
- The proposed sales model is designed to leave the Customer Choice program and its customers unaffected. The customer continues to have choice of commodity supplier between a Gas Marketer's fixed rate and the Terasen Gas variable rate. Customers electing to participate in the Customer Choice program may not be enrolled in the Green Gas program and any customer who is enrolled in the Green Gas program and who

elects to participate in the Customer Choice program would be automatically removed from the Biomethane tariff. Gas Marketer rules and functionality that are part of the Customer Choice program will remain unchanged.

- By electing to remain with Terasen Gas as the commodity supplier, a customer may choose to remain either on the standard rate (e.g., Terasen Gas Standard Rate Schedule 1) or they may select the Biomethane option (Terasen Gas Rate Schedule 1B – see Appendix F-3), which is understood to be a specific blend of Biomethane (10% Biogas; 90% conventional natural gas).
- The number of customers eligible to participate in the Customer Choice program will not be impacted and the Gas Marketer base load requirements will be calculated based on the same methodology that exists today. This methodology is defined as the Monthly Supply Requirement or MSR.
- Biomethane rates will typically be set on a forecasted 12 month period with the rate reset on a January 1 effective date (the initial offering anticipated effective October 1, 2010 will be based on a 15-month forecast period). The non-Biomethane commodity tariff rate will remain subject to quarterly rate adjustments, and the resulting blended commodity rate that customers will see on their bills could change up to four times a year as the standard commodity rate changes.
- The Biomethane residential tariff, a copy of which is included in Appendix F-3, will be an open tariff like the Terasen Gas Standard Rate Schedule 1 and allows for customers to elect to participate in and exit from the Green Gas program as they see fit. Customers currently enrolled with a Gas Marketer can only return to the Terasen Gas Standard offering, or enrol in the Biomethane tariff at the expiration of their Gas Marketer contract.[77]

The Company proposes to phase-in the implementation of the Green Gas program over a multi-year period in order to confirm market interest, demonstrate the ability of producers to deliver a reliable supply of Biomethane, and to verify that processes supporting the business model function effectively, while ensuring costs of supply are recovered by customers who opt into the program. The phased rollout is described below.

6.4 Phased Product Offering Strategy

The sales model the Company proposes to use for the Green Gas program is designed to be sufficiently flexible to enable a phased introduction of the Biomethane tariff option that allows for expansion of the product offering as additional supply becomes available. Two phases are planned:

[77] While not previously mentioned in Section 4, The Company's research of other green pricing programs elsewhere in North America found that the majority of green pricing programs offered by utilities have open entry and exit dates for residential customers. This source for this data is found in Appendix C-1.

- Phase 1 is expected to launch in Fall 2010, and is generally targeted at residential customers. The objectives of the initial roll-out of the Green Gas program will be to validate producer reliability and consumer interest. These objectives will be carried out by a flexible, simple, cost effective business model solution.
- Phase 2, currently anticipated to begin in the first quarter of 2012, will expand the product offering to match demand once supply has been further established and the Company's new Customer Information System ("CIS") is in place so as to minimize unnecessary incremental costs associated with an additional tariff offering.

6.4.1 PHASE 1 - PRODUCT OFFERING APPROACH

Phase 1 is directed at validating market demand, while remaining cognizant of the operational constraints presented by the Company's existing customer billing system.

The objective of market validation is addressed in Phase 1 by targeting the Green Gas offering at residential customers. Terasen Gas' research shows the highest uptake potential in the residential market; therefore, this sales model will allow for the maximum participation in a Green Gas offering while minimizing billing system impacts in the near term with one tariff. Leading with a single product (a 10% blend) will allow for tighter control over the number of enrolments and will match the limited supply in the first year. Actual residential customer use rates have a tighter range around an average than commercial customers, which will help to predict total consumption for residential customers who enrol in the program.

The Company was mindful to limit the number of customer billing changes associated with the Green Gas program with the Company's new CIS slated to "go live" on January 1, 2012. Terasen Gas recognizes that the Customer Works LP ("CWLP") upgrade costs that are included in the total program costs detailed in Appendix G, will not continue to provide value after the migration to its new CIS in 2012. The Company does not wish to incur any more costs on this system than are absolutely necessary to enable the launch of a Green Gas program. Terasen Gas is taking a measured approach to develop one rate offering which accomplishes cost recovery from customers who elect into the program but does not burden customers with increased costs to support multiple tariff and blend options.

Due to the limitations of the current customer billing system, the expense associated with overcoming those limitations and the limited amount of Biomethane supply available from the first two projects, the Company is delaying the launch of an expanded Green Gas offering to customers beyond residential at this time. In addition to giving Terasen Gas time to address these issues, the launch of an initial smaller Green Gas offering will provide the Company with the opportunity to gain experience in managing both Biomethane supply and demand. This initial offering will provide a springboard, from which to expand the program at an appropriate time in the future.

Terasen Gas did a system impact review to assist in assessing the required business systems and to help estimate the costs required to implement the new Green Gas offering to customers. The review included business process impacts and costs in various areas in order to implement the billing, tracking, reporting and management of a Green Gas program. A high level summary of this system impact review is described in Section 10.3.

Subject to the approval of this Application, effective October 1st, 2010, residential customers will have the option to enrol in Rate Schedule 1B, an open Tariff from which they can freely leave to return to Standard Rate Schedule 1 or to a Gas Marketer under Rate Schedule1U. The customers who elect Rate Schedule 1B will continue to receive supply from the Terasen Gas Distribution System, but will notionally be purchasing a blended Biomethane product.[78] Terasen Gas will recover the costs of the Biomethane through a 10% portion of the commodity line of customers who opt into the program, as detailed in the description of the proposed cost recovery methodology in Section 10. Customers currently enrolled with a Gas Marketer will not be eligible to enrol in the Green Gas program until their contract with the Gas Marketer expires or is terminated.

This Rate Schedule will be available in all territories served by Terasen Gas[79], with the exception of the Municipality of Revelstoke and Fort Nelson.[80] Eligible residential customers opting to purchase a blend of Biomethane through this program would be moved from their current tariff to Rate Schedule 1B, attached to this Application as Appendix F-3. The details of Rate Schedule 1B are nearly identical to Rate Schedule 1; however, the schedule has been updated to facilitate the Green Gas offering's specific needs. For example, an explanation that the cost of Biomethane includes the cost of service for Biomethane production.

Phase 1 supply of Biomethane is expected to range between a modest 0.05 – 0.23 PJ annually. As of December 31, 2009 there were approximately 752,000 Terasen Gas residential customers excluding Fort Nelson and Revelstoke, with just over 616,000 eligible to participate in the program that are currently not signed up with a Gas Marketer. Given average participation rates of 2.2%[81] in other jurisdictions, this opens the product offering to as many customers as possible, with the potential of the two supply projects included in this Application to be fully subscribed within the first phase of enrolment (2% of 616,000 customers would result in just over 12,000 enrolments and over 115,000 GJ/ yr of Biomethane at a 10% blend assuming an average annual residential use rate of 95 GJ / yr). As highlighted in Section 5, our customer research shows a residential market potential of 16%, but in order to err on the side of caution, for the first phase and in early days of the program, the Company is assuming industry averages for the first phase of the rollout of the Green Gas program. Should there be a larger market demand than anticipated, Terasen Gas is building into its offering the potential for a

[78] The concept of notional delivery is explained in Section 2.5.2 of this Application.
[79] Terasen Gas territory includes Lower Mainland, Inland and Columbia service areas.
[80] Revelstoke is served by a propane system and Fort Nelson has a separate Tariff.
[81] Refer to Appendix C-1: NREL, Green Power: Marketing in the United States: A Status Report (2008 Data), Page11

waitlist so that customers can be notified when more Biomethane supply is available for purchase. Such demand will feed into the number of supply projects that will be brought on for Phase 2 expansion of the Green Gas program.

6.4.2 PHASE 2 - EXPANDED PROGRAM

The objective of the second phase will be to expand the product offering to match demand once supply has been further established, and once the new CIS “goes live” on January 1, 2012.

This phase is foreseen to be launched around the first quarter of 2012. This phase will see the roll-out of a Commercial Green Gas offering to Rates 2 and 3 (called 2B and 3B), as well as higher blends from the currently proposed 10%. The rationale behind this decision is articulated in Section 5.4 of this Application; however, there is also some support for higher-percentage blends and offerings to small commercial customers as demonstrated in the supporting documentation. In addition, larger commercial customers and industrial customers have informally voiced interest in being included in a future expanded Green Gas program. As discussed in Section 11.2.2, Central Heat Distribution Limited (“CHDL”) has already committed to purchasing the first 10,000 GJs produced for the Green Gas program through Rate Schedule 11B (see Appendix F-6).

In the event of amalgamation with the other Terasen Gas companies and the potential implementation of an unbundled rate structure, Phase Two could also allow an expansion of eligible customers to include other regions such as Vancouver Island, the Sunshine Coast, Powell River, and Whistler. Further expansion to customers within Rate Schedules 4 to 7 is envisioned for 2013. All expansion of the Green Gas offering would be conditional on consumer interest and the availability of sufficient supply.

At this time, in respect of Phase 2, the Company is seeking approval of Rate Schedules 2B and 3B, which will become effective January 1st, 2012, allowing the launch of a Commercial Green Gas offering without additional Tariff changes, subject to the successful introduction of the new CIS. As the opportunity to expand the Green Gas offering approaches, the Company will file additional tariff schedules with the Commission. These Tariffs will adapt the changes made from Tariff 1 to create Tariff 1B to other rate classes and allow for higher blends of Biomethane as well (such as, for example, a 20% Biomethane blend).

The expected rollout to other regions and rate classes will be driven by uptake rates in the first phase of the program, as well as supply availability, and could be modified from time to time. The benefit of this sales model is that it will support additional rate offerings with little or no system impact starting 2012.

6.5 Projected Demand

While the Company's primary research indicates that there is a potential market for 16% of residential customers to sign up for a renewable energy-based program, the Company is mindful that other green pricing programs on average do not experience this type of participation rate. For the purposes of developing the program rollout strategy, the Company has analysed two scenarios:

- Ramping up to the industry average participation rate of 2.2%; and
- Ramping up to the potential market share identified in the primary research Study of 16% for residential customers and 10% for commercial customers.

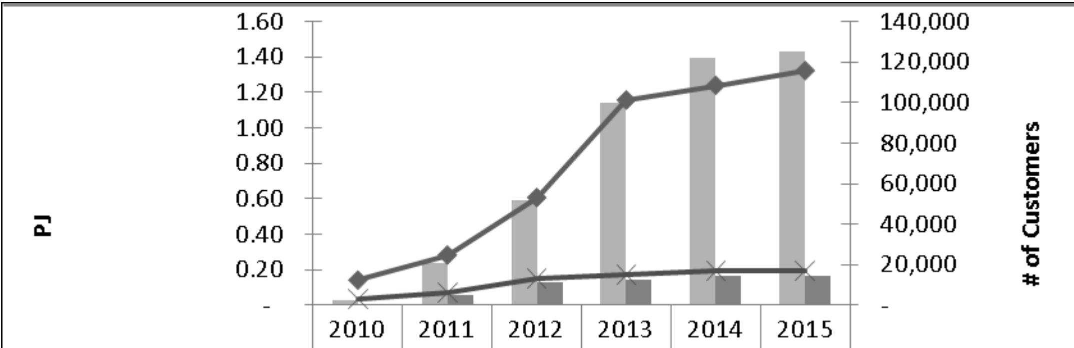
Each scenario is discussed below.

The low demand growth forecast outlined in Figure 6-1 anticipates that participation rates in the Company's Green Gas program will follow the industry average for other green pricing programs across North America. It is assumed that sign-ups will be effective October 2010 and participation rates will ramp up to the industry average of 2.2% over a 2-3 year time period and residential participants account for 90% of program participants. It is also anticipated that the program will first be launched to Terasen Gas Residential Rate 1 customers in years 2010-2011 and then start expanding to other rate classes and areas in 2012, assuming customer information system changes are streamlined. Therefore, 2012 would have the program expanded to Commercial Terasen Gas Rates 2 and 3, and, subject to amalgamation and the implementation of an unbundled rate structure, Terasen Gas (Vancouver Island) Inc. ("TGVI") and Tersaen Gas (Whistler) Inc. ("TGW") residential and commercial customers as well. Additional assumptions include: 18% of Terasen Gas Rates 1-3 customers would not be eligible to sign-up as they are currently with a Gas Marketer; participation rates will peak at 2.5% by 2014 (current industry average is 2.2% and climbing steadily); and average use rates for each rate class are used and in 2013 the program is extended to Terasen Gas Rates 4-7 customers. All volumes are also based on a 10% blend of Biomethane to each customer group. This translates into approximately 3,000 customers signing up for the program by the end of 2010, ramping up to over 17,000 customers by 2015 and volumes of 0.01 PJ to 0.16 PJ respectively.

The Company's high demand forecast assumes the same rollout timeline to various rate classes and regions, but utilizes the demand projections from the Terasen Gas research study performed by TNS. It anticipates ramping up to residential market participation of 16% and commercial participation of 10%. The results are significantly different starting at over 12,000 residential customers in 2010 ramping up to over 115,000 commercial and residential customers by 2015 and 0.03 PJs to 1.43 PJs respectively.

Figure 6-1 follows, which summarizes these projections.

Figure 6-1: Low and High Demand Scenario



	2010	2011	2012	2013	2014	2015
High Volume (PJ)	0.03	0.23	0.59	1.14	1.39	1.43
Low Volume (PJ)	0.01	0.06	0.13	0.14	0.16	0.16
High # of customers	12,340	24,679	53,061	101,159	108,416	115,662
Low # of customers	3,085	6,170	13,158	14,881	16,844	17,118

The low demand volume projections for the residential market match up quite well with the two near term supply projects included in this Application. The commercial volumes however do not appear reflective of the anticipated volumes that would be associated with their participation. Forecasting the commercial volumes using the average number of participants as other green pricing programs does not seem to account for volumes from customers that may have multiple premises for which they want to purchase Biomethane. Non-residential participants of other green pricing programs across the US represent 70% of the volume in green pricing programs. Using the number of program participants in the low demand scenario reflects only 7% of the program volume from commercial and the high demand scenario 36% of the Biomethane volumes. Therefore, estimating demand in the commercial sector is much more difficult. The commercial market rollout will have to be monitored closely to account for the wide range of demand scenarios. Terasen Gas anticipates that the associated volumes from the commercial market will likely be much closer to the high demand scenario.

These varying demand projections are another reason for the phased approach. The phased approach will allow Terasen Gas to gauge consumer demand and drive the supply project initiatives. If Terasen Gas does not see the anticipated sign-up rates in the residential target market in the first 15 months of the program based on the low demand forecast, additional supply projects may need to be reconsidered. Alternatively, if residential market demand is well beyond the low demand forecast, then supply projects will need to be brought on more aggressively to match demand. Terasen Gas plans to start a waitlist for customers that wish to be notified when new Biomethane supply becomes available should the program be oversubscribed.

6.5.1 TARGETED DEMAND

The targeted demand for the first 15 months of the program is to ramp up to a 1% participation rate by the end of 2011 in the Terasen Gas residential market with the goal to reach 2% by the end of 2012. This conservative estimate assumes no customer or volume growth, no backstopping to on-system or off-system sales customers or expansion to additional rate classes and results in take-up of 80% of the volume from the 2 projects proposed in this Application.

Table 6-1: Targeted Demand

		# of Customers	Volume	# of Eligible Customers[1]	% of Customers	Enrolments	Volume	Volume @ 10 %
Oct 2010-Dec 2010	Residential - Terasen Gas Rate 1	752,416	72,348,220	616,981	0.50%	3,085	73,267	7,327
2011	Residential - Terasen Gas Rate 1	752,416	72,348,220	616,981	1.00%	6,170	586,132	58,613
2012[2]	Residential - Terasen Gas Rate 1	752,416	72,348,220	616,981	2.00%	12,340	1,172,264	117,226

Notes:
[1] eligible customers are those not currently enrolled with a marketer
[2] 2012 projections do not include commercial market customers or growth in residential customers

6.6 Customer Education Plan

Communications will be critical to the successful implementation of a Green Gas program. As a Biomethane / natural gas blend is a new energy concept for residential use, Terasen Gas will need to educate customers about it in a simple, easy-to-understand manner. In addition to providing customers with details about the Terasen Gas Green Gas program, communications will motivate those interested in participating to make the decision to participate now. The uptake in Phase 1 will be key to encouraging future development of new renewable sources and sustainable platform from which to expand.. Therefore, communication activities will be a key component for educating consumers about Terasen Gas' Green Gas program and encouraging participation in the program.

6.6.1 CUSTOMER EDUCATION OBJECTIVES

There are four objectives for the communication efforts of the Green Gas program. They are to:

- generate awareness and understanding of Biomethane as a renewable energy and its availability today;
- generate awareness and understanding of the Terasen Gas Green Gas program;
- stimulate interest and participation in the program; and
- maintain participation and support for the program.

Customer education will be an ongoing activity until the Green Gas program reaches a level of market maturity whereby customer groups who have access to the program are sufficiently aware of it and able to make an informed decision as to whether or not they wish to participate in it.

6.6.2 CUSTOMER EDUCATION BUDGET

Terasen Gas is proposing a very modest customer education budget in order to achieve the targeted demand and customer awareness. In contrast to comparatively much larger budgets for programs such as Customer Choice, this initial budget for 2010-2011 is estimated at only $400,000 and will be amortized over three years (see Table 6-2 below for details). For purposes of the rate determinations included in this Application, $300,000 has been included for customer education in 2012, escalated annually thereafter by inflation (see Table 6-3 below for details). The proposed rate recovery mechanism for customer education is discussed in Section 10.4.

Table 6-2: Customer Education Budgets for 2010-2011

Type	Amount
Media	
Targeted print & online communications	$ 220,000
Direct marketing	20,000
	240,000
Production	
Print communications (incl. bill insert)	40,000
Videos	20,000
Event materials (incl. signage)	5,000
Quarterly email newsletter	20,000
	85,000
Promotions	
Incentives (for joining the program and/or referring others)	75,000
Total	**$ 400,000**

Table 6-3: Customer Education Annual Budgets for 2012-2013

Type	Minimum	Maximum
Media		
Targeted print & online communications	$ 100,000	$ 185,000
Direct marketing	0	20,000
	100,000	205,000
Production		
Print communications (incl. bill insert)	15,000	40,000
Video updates	0	0
Event materials (incl. booth signage)	0	5,000
Quarterly email newsletter	10,000	20,000
	25,000	45,000
Promotions		
Incentives (for joining the program and/or referring others)	25,000	50,000
Total	**$ 150,000**	**$ 300,000**

6.6.3 SUCCESS METRICS

The success of the customer education plan overall will be measured by:

- Mainstream media interest, indicated by quality and quantity of media coverage;
- Online activity, indicated by discussions on blogs and social media sites, links to program information on terasengas.com and traffic to our website;
- Awareness levels;
- Customer inquiries;
- Customer subscriptions;
- Subscriber referrals; and
- Rate of attrition.

Customer education will be an ongoing activity until the Green Gas program reaches a level of market maturity whereby customer groups who have access to the program are sufficiently aware of it and able to make an informed decision as to whether or not they wish to participate in it.

Additional Details of the Customer Education Plan are provided in Appendix H.

6.7 Tariffs Proposed in this Application

The Company is proposing three different tariff offerings under the Green Gas program:

A) Residential Tariff Offering (see Appendix F-3)

B) Commercial Tariff Offering (Small and Large) (see Appendices F-4 and F-5)

C) Sales Tariff Offerings (On-system (Rate Schedule 11B) and Amendments to Off-system (Rate Schedule 30) (see Appendix F-2)

D) Amendments To The Terasen Gas General Terms And Conditions To Allow The Offering Of The Green Gas Program (see Appendix F-1)

Terasen Gas is also proposing amendments to the Terasen Gas General Terms and Conditions to allow the offering of the Green Gas program.

6.7.1 RESIDENTIAL TARIFF OFFERING

The initial phase will be offered to Residential Rate Schedule 1 customers as a new Biomethane tariff that will be a specific blend of Biomethane and conventional natural gas. For this first phase of the program Terasen Gas proposes a blend of 10% Biomethane and 90% conventional natural gas. The Company proposes to make this initial offering to customers under the proposed Rate Schedule 1B (see Appendix F-3 for the Pro-Forma version effective October 1, 2010).

6.7.2 COMMERCIAL TARIFF OFFERING

The Company has included in this Application proposed Green Gas tariffs 2B - Small Commercial Biomethane Service (see Appendix F-4 for the pro-Forma version) and 3B - Large Commercial Biomethane Service (see Appendix F-5 for the pro-Forma version), which are proposed to be approved in this Application to be effective January 1st, 2012, subject to the successful introduction of the new CIS. Rate Schedules 2B and 3B as proposed would also be blends of 10% Biomethane and 90% conventional natural gas.

6.7.3 SALES (ON SYSTEM AND OFF-SYSTEM) TARIFF OFFERINGS AND AMENDMENTS

The Company also seeks approval of Tariff 11B. Rate Schedule 11B – Biomethane Large Volume Interruptible Sales (see Appendix F-6 for the pro-Forma version), that will allow for the sale of 100% Biomethane to on-system transportation only customers. The approval of this rate schedule will allow for the sale of 100% Biomethane to on-system transportation customers, who currently receive service from Terasen Gas under a transportation service schedule (Rate Schedules 22, 23, 25, or 27).

The Company also requests an amendment to Rate Schedule 30 – Off-system Interruptible Sales (see Appendix F-2 for the blacklined and pro-forma versions), to include a Transaction Confirmation sheet for specific Biomethane sales transactions. This Transaction Confirmation sheet includes details that are specific to Off-system Biomethane sales, more specifically, in addition to a commodity charge, the customer will be responsible for a delivery charge, which is proposed to be the same as Rate Schedule 27's current delivery charge, and will be revised as required when Rate Schedule 27 is revised.

The delivery charge (that will be incorporated within an inclusive commodity charge to the customer), is necessary and required to facilitate the movement of Biomethane gas from the Terasen Gas distribution system to the off-system custody transfer point of Huntington, in order for the customer to purchase the gas.

The Company is also proposing an amendment to the current GasEDI contract included in Rate Schedule 30 under Section 2 Definitions to amend the definition of Gas to include Biomethane.

Both Rate Schedule 11B and the amended Rate Schedule 30 are an integral part of the Company's risk mitigation strategy to ensure excess Biomethane can be sold to customers outside of the Green Gas offering, enabling Terasen Gas more flexibility to meet the needs of customers and suppliers as the marketplace for this service matures. The Company is proposing that both of new Rate Schedule 11B and the amended Rate Schedule 30 be effective October 1, 2010.

6.7.4 AMENDMENTS TO THE TERASEN GAS GENERAL TERMS AND CONDITIONS TO ALLOW THE OFFERING OF THE GREEN GAS PROGRAM

The Company is proposing amendments to Terasen Gas' General Terms and Conditions to allow the Green Gas program to be offered. (see Appendix F-1 for the blacklined and pro-forma versions).

Specifically, Terasen Gas is proposing to add new definitions relating to the Biomethane Service, and the introduction of a Section 28 – Biomethane Service. The Company requests that these amendments be effective upon the approval of this Application by the Commission.

6.8 Conclusion

Terasen Gas believes that the Green Gas offering proposed in this Section provides a comprehensive end-to-end business model, from demand to supply, developed to ensure Biomethane is made available in a manner which will satisfy customer needs and requirements.

7 SUPPLY IN BRITISH COLUMBIA

7.1 Introduction

As described in Section 2 of the Application, Biogas is available from a wide variety of sources and can be upgraded through the use of several different types of technology. While the most optimistic estimates of potential supply of Biomethane in British Columbia may in some cases exceed the demand forecasts that Terasen Gas has identified in this Application, the Company is committed to developing its supply of Biomethane in harmony with the development of customer demand for the product.

In this Section, Terasen Gas discusses supply development activities and the potential supply of Biogas in British Columbia.

7.2 Biogas Supply Activities in British Columbia are Moving Forward

There is a strong interest from potential Biogas suppliers in partnering with Terasen Gas to develop Biogas supply.

In the fall of 2009, Terasen Gas initiated a process to determine interest in the development of Biogas supply in British Columbia. Information sessions were held around the province and Terasen Gas issued a Biogas “Request for Expressions of Interest“(RFEOI) to further clarify possible projects. Terasen Gas received a total of nine (9) specific proposals in response to the RFEOI, covering a wide range of industries and technologies. The expressions included a wastewater treatment plant, an on-farm digester and a landfill gas project. These project types form the basis of the possible future supply of Biogas in British Columbia.

Since the RFEOI, Terasen Gas has continued to receive inquiries and expressions of interest from potential supplier developers. In the last year, Terasen Gas has received on average one additional inquiry per month. Currently, there are more than twenty (20) potential projects of various sizes at various stages of evaluation by Terasen Gas in different locations around the province. At this time, Terasen Gas also continues to discuss potential future projects with possible partners.

There is a significant potential supply of Biomethane within the Terasen Gas service territory. Many of the prospective partners that are interested in working with Terasen Gas have the potential to offer long-term supply to the utility. Terasen Gas intends to take a measured approached to bringing these supply sources to market. Projects will be evaluated and implemented when required to meet demand for Biomethane over time.

7.3 Size of Supply in British Columbia

Terasen Gas prepared a preliminary estimate of potential Biomethane supply in British Columbia in order to get an idea of the possible impact on conventional supply and to determine if future demand could be met. According to the preliminary estimate prepared as described below, the range of expected annual Biomethane supply available to Terasen Gas customers is between 2.2 Petajoules (PJ) and 5.6 PJ by the end of 2020.

7.3.1 TEN-YEAR BIOMETHANE SUPPLY FORECAST

Terasen Gas prepared its preliminary Biomethane supply forecast in four basic steps:

- First, Terasen Gas estimated the total amount of bioenergy available in the province.
- Second, the total amount of possible energy available for Biomethane supply was then reduced by excluding unlikely sources.
- Third, the remaining amount of energy was then further reduced by applying a probability of success to projects. Three scenarios were generated by changing the probability of development and the timing of the projects.
- Fourth, Terasen Gas estimated near-term Biomethane supply based on known possible projects at the time of filing.

The result of the near-term supply assessment was combined with the high level forecast to create an aggregate forecast. The following paragraphs include a more detailed description of each step undertaken in estimating the Biomethane supply, and the results of each step.

Step 1 – Total amount of Bioenergy in BC

Table 7-1 below is a summary of the waste sources in BC showing the included and excluded bioenergy resources used in the supply estimate. The table is derived from a discussion paper developed by the British Columbia Bioenergy Network.[82] According to this reference, the total amount of Bioenergy in BC is approximately 529 Petajoules (PJ).

[82] Page 5, British Columbia Bioenergy discussion Paper, Joshi, Robert, 2008 for the BC Bioenergy Network

Table 7-1: Gross Bioenergy Resources in British Columbia

Source	Energy (PJ)	How Source is Accounted for in Estimate
Forest Residue`		
Residues	182	Exclude
Current use, excluding Mountain Pine Beetle Kill	205	Exclude
Agriculture-Food Resources		
Residues, Fats, Oils, Greases	10	*Include*
Municipal Resources		
Solid Waste & Wastewater	*21*	*Include*
TEMPORARY		
Mountain Pine Beetle- killed wood	43	Exclude
Landfill Gas	5	*Include*
Growing Resources		
Forests	43	Exclude
Agriculture	20	*Include*
Total Energy in BC	**529**	
Total Gross Useable for Bioenergy	***56***	***Shaded numbers ONLY***

Step 2 – Exclusion of Bioenergy Resources not suitable for Biomethane

As noted above, the total estimated potential bio-resources in BC are estimated at approximately 529 Petajoules per year. That number, however, contains resources such as mountain pine beetle killed wood. In order to develop a more realistic estimate, all forest-related organic waste was excluded from the total potential supply. Wood waste was excluded because the process of converting wood waste to Biomethane is different than other organic waste. Equipment to process wood waste into Biomethane is not well-established and is not readily available.

Once the wood-waste is excluded, the remaining estimated total amount of possible, useable bioenergy for Biogas projects is approximately 56 PJ per year. This is illustrated in the bottom line of Table 7-1 above.

Step 3 – Estimate range of supply

In order to develop a range of supply, estimated high and low percentages of developable projects were applied along with high, low and expected success rates. The success rates take into account two primary factors.

The first factor is the percent of developable projects. This number is meant to take into account the proximity of waste sources to the existing natural gas distribution system and variation in project economic factors. That is, though there may be a source of gas, it may not be located near the distribution system. Alternately, the project economics may not work. The economics of the project depend on a number of factors such as amount of Biogas available, the price paid for the gas, the cost of upgrading equipment or operating costs. At this point these factors are not known, but it is expected that only a portion of the projects will have factors favourable for the development of Biomethane supply.

The second is the likelihood of the development of a Biomethane project versus an electricity generation project or the possibility that no project would ever be developed. That is, for the total number of projects only a certain number will become Biomethane projects and the remainder would be something else (most likely electricity generation or nothing). To illustrate, the low estimates assume that only 20% of the bioenergy available is developable (close to the Terasen Gas distribution system, economically viable) and there is a 20% success rate (1 in 5 projects go forward if they are developable). These probabilities are based on a limited amount of known data at the time of filing. The probability of success could change significantly if, for example, there is a shift in project development more heavily toward electricity generation projects due to the BC Hydro call for Community Biomass Energy projects.

Table 7-2: Probabilities used in Biogas Supply Projections

	% of Developable Projects	% of Biomethane Projects
Low	20%	20%
Expected	25%	30%
High	25%*	40%

*25% is the expected and the high value for developable projects. However, this is based on the experience gained in the first year of project evaluation.

The rate of the development of projects was also estimated, assuming that larger projects would happen sooner than smaller ones based on better economies of scale being expected for the larger projects.

Step 4 – Develop Short Term Supply Estimate

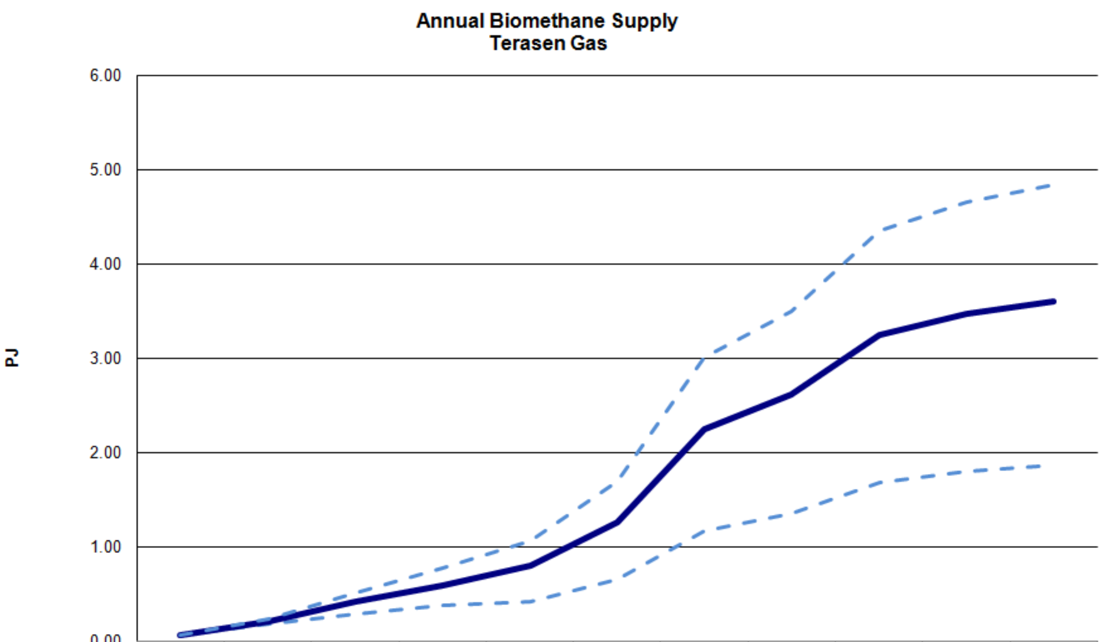
As mentioned, Terasen Gas has already engaged in discussions with possible partners to develop Biomethane supply. Each of these partners - in cooperation with Terasen Gas - has developed a preliminary energy production estimate. In addition, Terasen Gas has done a preliminary evaluation of a possible system tie-in location. Because some initial work has been done on these projects, Terasen Gas was able to develop a better quality estimate for the next four years.

More specifically, for the first four years of the estimate, a known energy potential from known supply partners as of the date of this filing was used. Each project was assigned a likelihood of success for low, expected and high (in percent) and multiplied by the energy available. The possible timing of the project was then factored in to forecast an aggregate supply.

7.3.2 RESULTS OF PRELIMINARY SUPPLY ANALYSIS

The ten-year and four-year forecasts were then combined to give an aggregate estimated Biomethane supply until the year 2020. The resulting total supply curves are a combination of the foregoing factors. They are shown below in Figure 7-1.

Figure 7-1: Terasen Gas Forecast for Annual Biomethane Supply



	2010**	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Low	0.05	0.18	0.29	0.38	0.41	0.65	1.16	1.35	1.68	1.79	1.86
Expected	0.05	0.21	0.41	0.59	0.79	1.26	2.25	2.61	3.25	3.47	3.61
High	0.05	0.23	0.50	0.76	1.06	1.69	3.01	3.50	4.35	4.66	4.84

Applying this analysis, the estimated annual Biomethane supply volumes by 2020 are 2.2 PJ on the low end, 4.2 PJ expected and 5.6 PJ on the high end. The forecast until the end of 2013 is between 0.38 PJ and 0.76 PJ annually.

The data used to produce the ten year estimate is new and the supply forecast methodology is still in development. The size of projects, the success rates, the total amount of bioenergy available and the sources of the energy are not well-established. Terasen Gas believes that the estimate for the first four years is more accurate than the longer term forecast because it is based on existing discussions and project locations, but it is still subject to some uncertainty.

Once the first two projects proposed in this Application are in service, Terasen Gas will have reference cases that can be used to better estimate actual versus projected supply. Reference cases will also help to establish confidence that projects can be successfully completed. The estimate assumes that the first two projects are completed on time and operate within expected bounds of supply volumes and costs. The current estimates also assume that the current governmental policies and partner support for Biogas development remain the same for the next ten years. Terasen Gas will re-evaluate the supply forecast on an annual basis to take into account changes in the inputs (such as actual vs. projected supply volumes) and government policy.

7.4 Conclusion

Terasen Gas believes that there is sufficient raw Biogas supply to develop the Biomethane required for the planned customer offering in the near term. This is based on the strong interest from various potential partners to work with Terasen Gas to develop Biomethane projects within the Terasen Gas service territory. The long-term forecast (to the year 2020) shows that the expected Biomethane supply is in the range of 1.86 to 4.84 PJ which should be a significant portion of the total supply portfolio in the future. At this point in time, the long-term forecast is preliminary but it will be developed further as operating data experience is gained from the first supply projects. Terasen Gas can pursue additional supply in tandem with growth in demand for Biomethane.

8 SUPPLY SIDE BUSINESS MODEL

8.1 Introduction

The key objective of this Application is to safely and economically meet the customer demand for Biomethane. Terasen Gas has developed a flexible model for acquiring an economic supply of Biomethane, while retaining control of the interconnection facilities that ensure the Biomethane injected in to the distribution system is safe and interchangeable with natural gas. In this Section, Terasen Gas describes two business models for acquiring Biomethane. These business models are employed in the two projects described in Section 9, and involve Terasen Gas entering supply agreements for either raw Biogas requiring upgrading or (already upgraded) Biomethane. In addition to seeking approval of two executed supply contracts and Terasen Gas' proposed investment in project related facilities, Terasen Gas is also seeking approval of guidelines that will determine the process under which the Commission will review and approve future Biogas and Biomethane supply contracts. The Commission's endorsement of the proposed directions on future process will facilitate the growth of the supply industry and set clear and achievable goals for our potential supply partners.

This Section provides:

- An overview of the two supply side business models that Terasen Gas is proposing;
- The scope of Terasen Gas' involvement in the proposed supply models; and
- Terasen Gas' proposed approach for obtaining additional Biomethane supply, including a proposed maximum Biomethane cost.

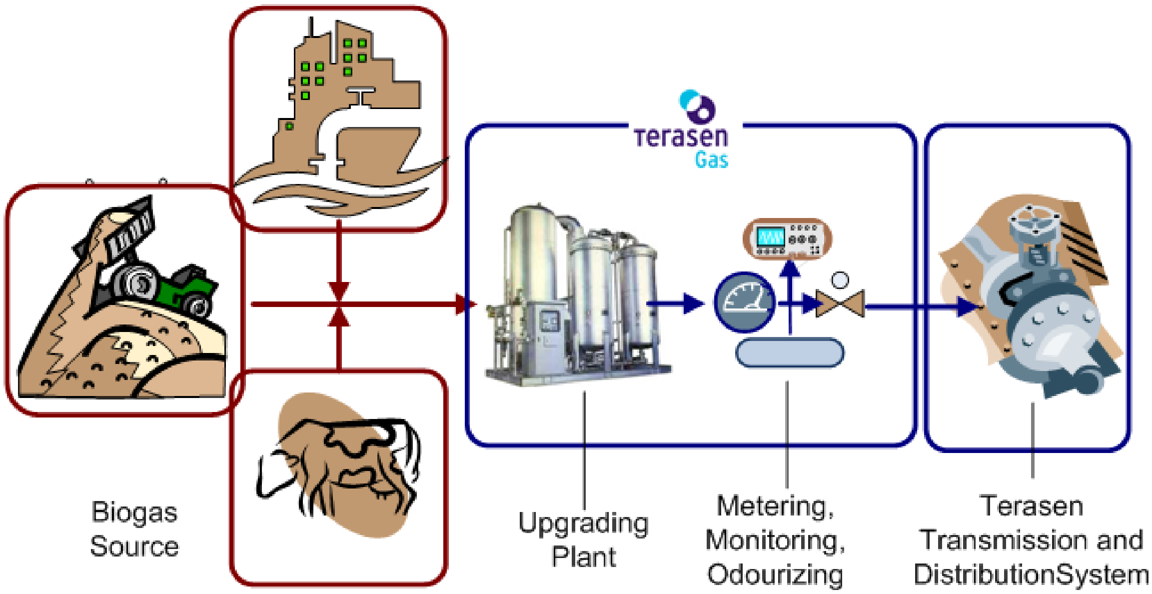
8.2 Ownership Model

The Company's ownership model contemplates the partner retaining ownership and control over the equipment which digests organic material to create raw Biogas, as well as those assets required to collect raw Biogas from proposed collection locations such as digesters, landfills or sewage treatment facilities. Those assets require the largest investment and currently fall outside Terasen Gas' core expertise. However, Terasen Gas will generally control the upgrading process and will always control the interconnection facilities. Controlling the upgrading process and associated facilities ensures that the process is undertaken in a manner that produces a consistent and reliable supply of Biomethane. The exception will be where the partner can be appropriately relied upon to provide this consistent supply of properly upgraded Biomethane. Terasen Gas must control the interconnection equipment to retain complete control over the gas injected into the distribution system.

The model, shown below in Figure 8-1, requires Terasen Gas to own and operate the upgrading equipment in addition to the interconnection equipment. The partner owns the digester.

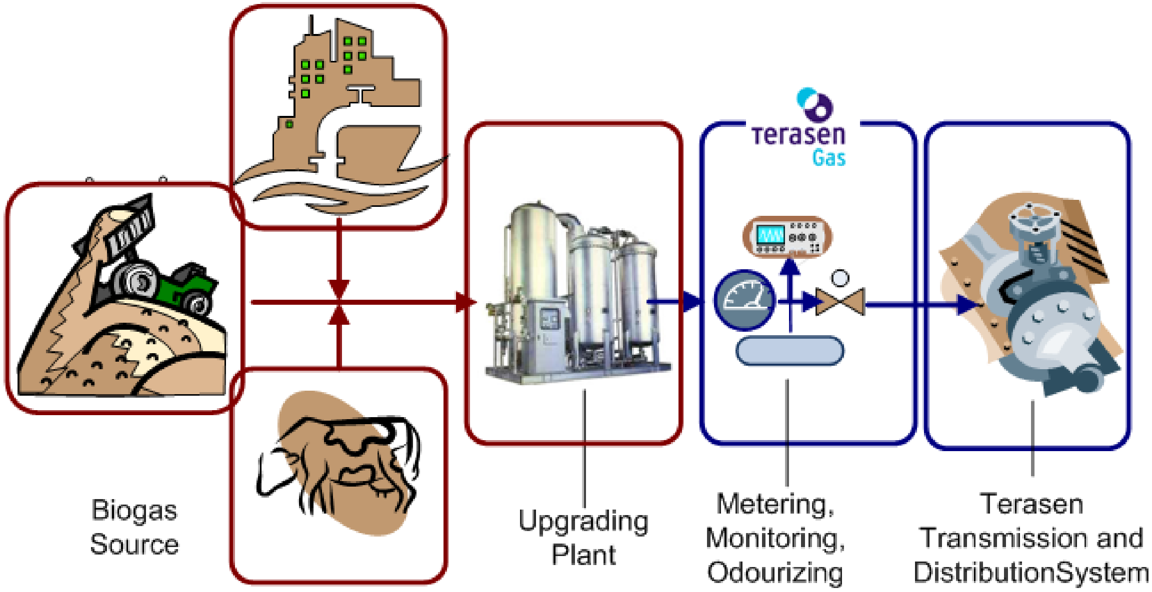
Terasen Gas is purchasing raw Biogas, and is upgrading it to Biomethane for injection into the Terasen Gas system. An example of would be a municipal operation that produces Biogas that would otherwise be wasted, but lacks the capital or experience to operate upgrading equipment.

Figure 8-1: Company's Role in Biomethane Projects



As indicated above, when project partners that meet the Company's financial and technical standards required to own and operate the upgrading equipment can be found, the Company will allow a variation on this model, shown below in Figure 8-2 An example of this would be an entrepreneurial operation that has constructed an anaerobic digester and owns the upgrading equipment.

Figure 8-2: Exception to Ownership Structure



8.3 Scope of Terasen Gas' Involvement in Two Supply Models

As illustrated in Figure 8-1 above, there are three distinct facilities required to get the raw resources converted to Biomethane and injected into Terasen Gas' distribution system. They are:

- The Biogas source and related facilities to harness the Biogas;
- The upgrading plant and equipment; and
- The interconnection facilities.

In the paragraphs that follow, Terasen Gas elaborates on the extent of its intended involvement and ownership of facilities in the context of the two supply models.

8.3.1 PARTNER WILL OWN BIOGAS SOURCE OR DIGESTER

Terasen Gas contemplates that its partners, and not Terasen Gas, will own, operate, construct and maintain the assets associated with anaerobic digestion or the collection of Biogas.

At this time there are project partners willing to develop supply projects by sourcing Biogas from their facilities. This investment by potential partners is a natural extension of their core business. For example, in an agriculture situation the owner must manage their waste; therefore, collecting the waste into a digester to produce Biogas is a logical processing step for the farm to take.

The development and collection of raw Biogas is the most capital intensive portion of any given Biogas/Biomethane project. In the case of a digester project for example, investment will typically include the following items:

1. Acquisition of land
2. Collection of waste that is input to the digesters
3. Management of stockpiled input waste
4. Construction and operation of digesters
5. Construction and operation of mixing (processing) equipment
6. Construction and operation of the Biogas collection system
7. Construction and operation of a back up flare system

In the case of a landfill project, there is also a large investment on the part of the project partner in order to collect and provide raw Biogas. The investment includes:

1. Construction of a gas collection system
2. Construction of a gas capture system (membrane, condensate collection)
3. Installation and operation of a mechanical system for gas collection (flow control and monitoring)
4. Construction and operation of a back up flare system

When looking at a Biogas project as part of a wastewater plant, a Biogas project would take advantage of a gas that is being collected and flared as a waste product from the plants existing facilities. The Biogas is a minor portion (in terms of the capital investment) of any wastewater treatment plant. Municipalities and regional districts will spend millions of dollars in sewage collection as well as primary and secondary treatment. For example, the Capital Regional District is planning to spend approximately $930 Million for four (4) wastewater plants in the City of Victoria and immediately surrounding area[83,] In contrast, the investment in Biogas upgrading equipment would be on the order of magnitude of 1% of the initial cost of a project like this. Similar to the above discussion, the Capital Regional District will have other potential uses for their Biogas, and if Terasen Gas is not able to step in and provide safe, reliable and economical upgrading this potential supply of Biomethane might not be developed and therefore not reach customers.

In conclusion, Terasen Gas is not proposing to invest in assets, the purpose of which is the collection of raw Biogas or the digestion of materials in order to create raw Biogas. The partner will bear the risk and reward associated with their assets, and the Company will seek to ensure that associated assets under our management are, to the extent reasonably possible, able to be

[83] Capital Regional District, Business Case in Support of Funding Under the Infrastructure Canada Building Canada Fund - Major Infrastructure Component, Published 9, December 2009.

re-used, relocated or sold in the event of an unsuccessful project. Risk mitigation is addressed in Section 11.

8.3.2 TERASEN GAS OWNERSHIP AND CONTROL OVER UPGRADING FACILITIES

The technical aspects of Biogas purification are discussed in detail in Section 2 of this Application. This portion of any project is different from raw Biogas production because of the input and outputs to the process. It is purely a gas processing and gas management step in the process. The input to the process is raw Biogas and the output is Biomethane. This falls within the core expertise of Terasen Gas, and Terasen Gas 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 from the project.

It is expected that Terasen Gas will buy raw Biogas from a project partner, provided it meets an expected composition, and control the upgrading process. The cost of raw Biogas will be included in the COS model along with all of the capital costs of the particular supply project, including the upgrading cost and the cost of the main extension.

The key features of this model are as follows:

- Terasen Gas secures a purchase agreement with partner for raw gas – typically low purchase price than upgraded Biomethane.
- Terasen Gas reserves the right to refuse gas that does not meet specification.
- Terasen Gas has control over the optimization of Biogas to Biomethane.
- Terasen Gas invests in upgrade equipment (purification of gas).
- Terasen Gas invests in interconnection station (meter, monitor, odorize).
- Terasen Gas invests in distribution system extensions or upgrades.
- Terasen Gas operates and maintains investment.

Advantages:

- The Company is able to best ensure the safe, reliable and economic delivery of Biomethane to the distribution system.
- Terasen Gas retains control over the Biogas to Biomethane upgrading process. Terasen Gas can optimize operations and balance final gas quality with total volume of Biomethane.
- Terasen Gas has a control point further upstream of measurement and monitoring equipment. This model has the advantage of providing Terasen Gas with an ability to exercise greater control over gas quality and customer and equipment safety.

Disadvantages:

- This model requires a material capital investment by Terasen Gas.

In some cases, project partners will desire to own and operate this equipment and sell upgraded Biomethane to Terasen Gas. Terasen Gas will only consider this option where the partner can satisfy the financial and technical standards of Terasen Gas.

In summary, 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. When project partners capable of meeting that requirement can be found, this flexible ownership model will allow the parallel creating of an independent Biomethane upgrading industry in British Columbia. It is important for Terasen Gas to retain the flexibility to consider the options that are in the best interests of customers in each case. The cost of service model proposed by Terasen Gas will ensure that the unit cost of delivered Biomethane, regardless of the model employed to obtain it, is reasonable.

8.3.3 TERASEN GAS OWNERSHIP AND CONTROL OF INTERCONNECTION FACILITIES

In all scenarios, Terasen Gas will own and operate the interconnection, and connect the Biomethane plant to the Terasen Gas distribution system using standard equipment that is already a part of our core business. In particular:

- Mains or service lines will be used depending on the amount of gas forecast to flow from the plant.
- Meters will be used to measure the amount of gas injected into the distribution system to allow for the proper compensation of the Biogas supplier, and more importantly to ensure that, for safety purposes, only the agreed to amount of gas flows to the local area in which the plant is situated.
- Odorant will be added to the gas as it enters the distribution system requiring appropriate equipment and supply of odorant at the plant site
- Gas analysing equipment owned and operated by Terasen Gas will also be present at each site to ensure that, for the safety of all customers, the gas entering the system meets the agreed to specifications for chemical and heat content.

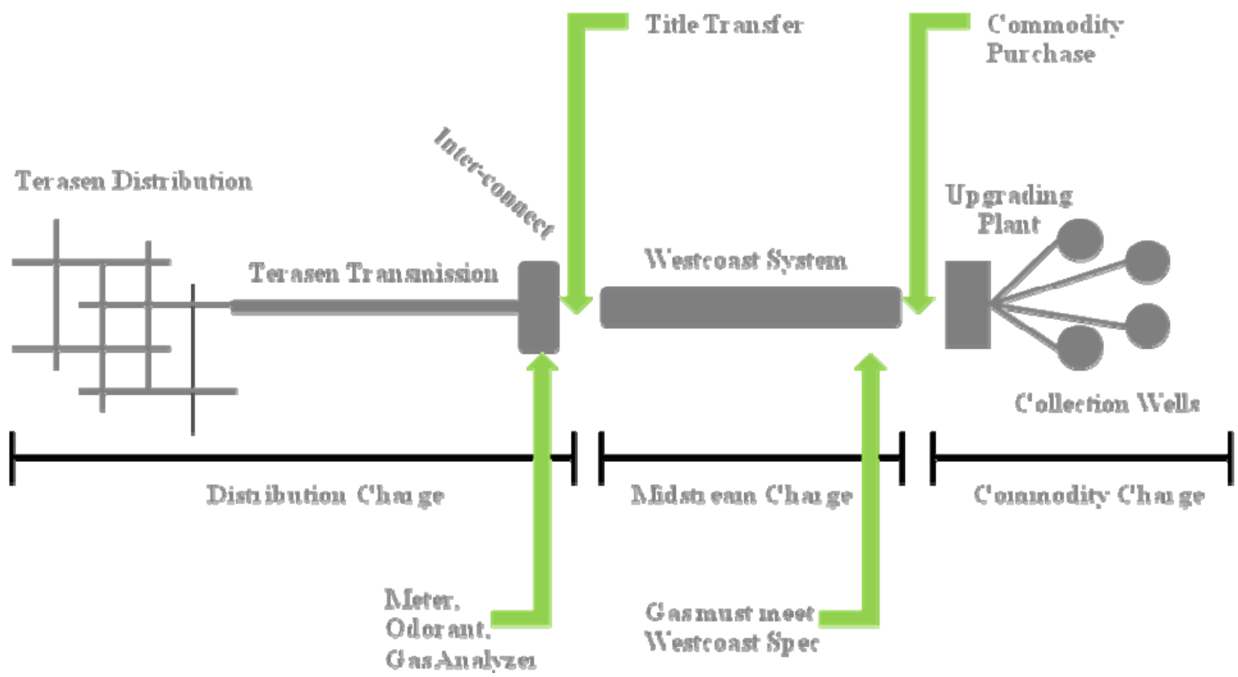
Terasen Gas must in all cases retain ownership and control over the interconnection in order to ensure the safety and reliability of the Terasen Gas system.

8.3.4 COMPARISON TO TERASEN GAS' CURRENT NATURAL GAS SUPPLY CHAIN

The approach proposed above for upgrading facilities is conceptually similar to the way in which the natural gas supply chain is currently operated.

The current gas supply chain is illustrated in Figure 8-3 below.

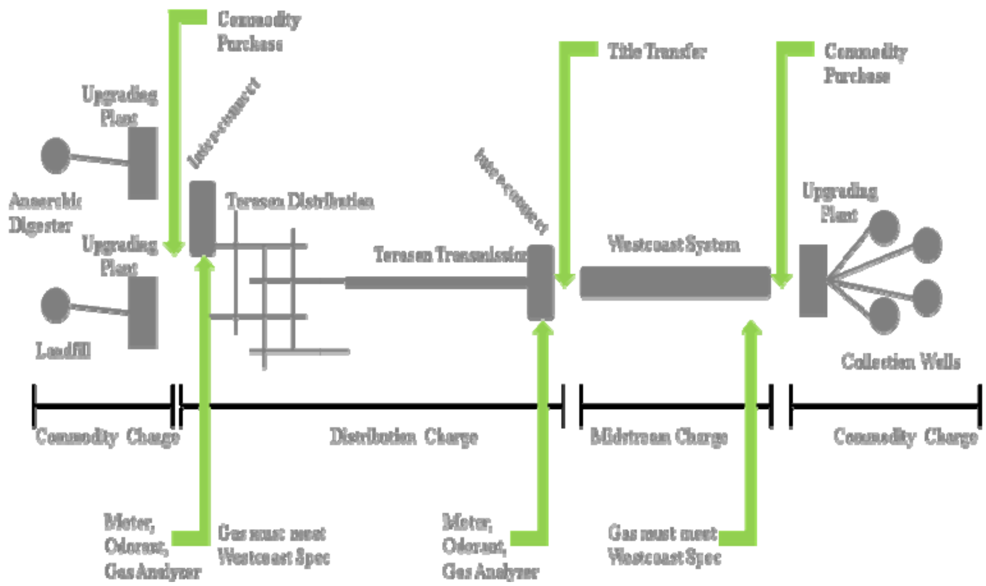
Figure 8-3: Current Structure of Natural Gas Supply Chain and Cost Recovery



Under the current supply value chain, producers produce raw natural gas from wells into gathering lines to move the raw gas to a production plant where the gas is upgraded into pipeline quality gas. It is common industry practice for the producer of the raw gas to sometimes own and operate the upgrading facilities (plant). At other times, depending on the circumstances, this raw gas is upgraded in third-party facilities.

Figure 8-4 illustrates where Biomethane injection falls in relation to the existing natural gas distribution system (to the left of this diagram).

Figure 8-4: Structure of Natural Gas Supply Chain with Biomethane



As can be seen from the comparison between these two figures, the change in structure is a subtle one. Customer rates continue to contain the cost impacts of the same types of Midstream and Distribution infrastructure that the Company is already in the business of owning and operating, while also paying the Commodity recovery rate associated with the production and acquisition of the gas that they chose to consume.

8.4 Assessment of Future Projects

The Company will assess future supply projects against a number of guiding principles, key among them is an economic test that ensures the delivered cost of Biomethane supply remains within acceptable parameters. The adoption of this framework in advance will facilitate the growth of the supply industry by establishing clear and achievable parameters for our potential supply partners. Terasen Gas is proposing to use these guiding principles as the basis for establishing a streamlined regulatory review process that will apply to future supply contracts for Biogas and Biomethane submitted by Terasen Gas.

8.4.1 GUIDING PRINCIPLES FOR DEVELOPMENT OF BIOMETHANE SUPPLY

Terasen Gas intends to apply a number of guiding principles to the development of future Biomethane supply. They are set out below.

A) Project Economics

A cost of service (COS) model will be used to evaluate the attractiveness of projects. The key inputs to the model will be the estimated capital and operating costs borne by Terasen Gas and the estimated production of Biomethane. Each project will be evaluated against a cost of service threshold that will represent the maximum cost of Biomethane delivered to the Terasen Gas system, currently proposed to be $15.280/GJ as described in Section 8.4.2.1 below. The cost of service will also include any payments made for either raw Biogas or Biomethane.

B) Gas-Processing Technology

Terasen Gas will use proven technology in order to ensure reliability and safety for our customers. The technology will be evaluated on the basis of cost (both capital and operating), output gas purity and gas recovery (a measure of efficiency).

C) Working with Biogas Project Proponents

Terasen Gas will work with Biogas project proponents to mitigate project risks. For example, the Company will seek to partner with businesses or organizations that are financially sound and reputable. The Company will also address the business risks of each Biogas project with appropriate contractual terms.

D) Cost Recovery

Terasen Gas intends to 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 who participate in the Green Gas program.

E) Gas Quality

Biomethane that is injected into the system must meet minimum Terasen Gas quality specifications. This specification will ensure that the Biomethane is equivalent to the existing natural gas that is supplied onto the Terasen Gas system.

F) Injection Location

The Company will evaluate all projects on a case-by-case basis to ensure that the injection location has sufficient local demand to utilize Biomethane. Gas injection is preferred on the distribution system at pressures less than 700kPa. Gas injection may also be considered on Intermediate Pressure (IP) lines.

G) Contract Length

It is preferred that Terasen Gas enter into long term contracts (10 years or more) where possible to allow for a stable supply and reasonable depreciation period for the capital investment.

H) Project Design for Mobility

Terasen Gas will engineer facilities in order to minimize the risk of stranded assets. Consideration will be given to the future mobility of gas processing or quality equipment.

I) Investment Arrangement

Terasen Gas prefers to invest in upgrading equipment to retain maximum control of gas quality and safety. The Company 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 Gas will reserve the right to refuse gas if customer safety or asset integrity is at stake. For a more detailed description of the supply model investment arrangement see Section 5 of this application.

Terasen Gas believes that the guidelines described above will allow for the safe, economic and timely development of additional Biomethane supply projects to ensure that demand for Biomethane and supply of Biomethane come into balance over the medium to long term. Setting clear expectations of prospective project partners, and a transparent process will reduce the possibility of project proponents losing capital due to investment in projects that do not meet the needs of Terasen Gas and its customers.

8.4.2 MAXIMUM BIOMETHANE COST

Consistent with the requests put forward in the Terasen Gas 2011-2012 Revenue Requirement Application, Terasen Gas intends to apply a maximum cost for screening the supply of Biomethane. The primary reason for this proposal is that the Company wants to ensure it has adequate flexibility in developing new sources of supply, while ensuring that customers who agree to purchase the gas are protected from undue rate increases as a result of rapid development of more expensive Biomethane supply. Further, given BC Hydro's entrance into the Biogas market as described in Section 7.3.1, setting 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.

8.4.2.1 BC Hydro RIB Tier 2 Rate as Basis for Determining Maximum Biomethane Cost

Biomethane is a new energy supply source in British Columbia. There are no available external pricing benchmarks specific to Biomethane that assist in setting a threshold price or cost. Conventional natural gas does not provide an appropriate reference point for the price of Biomethane as it is a product that has fundamentally different environmental attributes, even though it may be chemically interchangeable. The Company believes that the price of new BC-based electricity supply, a competing clean energy source in the province, provides an appropriate initial reference point for Biomethane pricing until the market for this new clean energy resource is better developed.

By Commission Order No. G-124-08, the Commission instructed BC Hydro to establish the RIB Step 2 rate at BC Hydro's cost of new supply at the plant gate, grossed up for losses. Since the RIB Step 2 rate is linked to BC Hydro's cost of new clean electricity supply, it is an appropriate price cap for Biomethane (after adjusting for thermal efficiency and allowances for Terasen Gas distribution costs) for use in the economic analysis in the early development stages of pipeline Biomethane as a resource. In other words, the RIB Step 2 Rate can be used as a proxy starting point for the competitive cost of new thermal energy supply. It is also the electricity rate that many residential customers may pay for space heating in the winter months when their electricity usage is high, and is therefore an alternative heating option to Biomethane.

Terasen Gas is therefore proposing that, until such time as an alternative reasonable market-based mechanism or proxy becomes known, the Company will seek to develop Biomethane projects at a maximum unit cost based on a calculation as follows:

Table 8-1: 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

This means that Terasen Gas is proposing that a forecast maximum unit cost of $15.280/GJ be the default financial litmus test for the time being for whether or not to develop Biomethane projects. In Terasen Gas' rate structure, this price would be comparable to the commodity price for conventional natural gas.

The proposed maximum forecast rate will be adjusted in line with the following unit cost change triggers: the Terasen Gas Rate Schedule 1 Basic, Delivery or Midstream Charge, or the BC Hydro RIB Step 2 Rate. When any of these changes occur, Terasen Gas will notify the Commission of the change and the resulting impact on the maximum unit cost, with a request for approval of the new proposed maximum unit cost. Terasen Gas does not propose that this would result in retroactive price adjustment of projects previously brought online.

Terasen Gas is mindful of customer value and the importance of consumer price sensitivity to the success of the program, and will endeavor to minimize the cost of Biomethane it makes available to its customers, while balancing the need to grow the available pool of Biomethane to meet customer demand.

84 BCH F2011 RRA, Appendix A1, Page 2, Table 2

8.4.2.2 *Alternatives Considered for Economic Test*

In developing the above economic screen for supply project development, Terasen Gas considered five alternative methodologies to the RIB Tier 2 rate:

- BC Hydro Clean Energy Rate
- South East False Creek District Energy System
- Dockside Green Energy
- Gas Commodity Rate Cap
- No Cap

However, using the RIB Tier 2 rate, as adjusted from time to time, made the most sense as an economic screen. In this section, Terasen Gas discusses each alternative and the rationale for not pursuing that methodology.

The first possibility to consider was to use a higher BC Hydro Clean Energy rate as a proxy for a competitive alternative to Biomethane. On March 3, 2010 BC Hydro filed its F2011 Revenue Requirement ("BCH F2011 RRA"). Included in Appendix A1 to the BCH F2011 RRA, was the statement that an upcoming filing in relation to a pending Clean Energy Call could set the marginal cost of new clean electricity at $0.13/kWh[85]. Using the above conversion formula, the comparative price for Biomethane would be $25.83/GJ. Terasen Gas is of the opinion that it must protect its competitive standing. Biomethane costs will be streamed directly to Terasen Gas customers whereas these higher clean electricity costs will be mixed into a large pool of lower-cost electricity to BC Hydro customers to form the RIB Step 2 Rate. The Company believes that tying the price of Biomethane to a proxy price that is directly observable by customers, such as the RIB Step 2 Rate, is the superior solution.

Terasen Gas also considered as a proxy BC Hydro's stated Maximum Adjusted Price for electricity generated from bioenergy. On May 31st, 2010 BC Hydro published their Phase 2 Call Request for Proposal documents. On page 2 of the "Bioenergy Phase 2 Call RFP", BC Hydro states that they will pay up to a maximum of $150 per MWh[86] of firm electricity made from renewable biomass energy. BC Hydro's description of biomass energy includes the same materials used to produce biogas through anaerobic digestion. Assuming the same multiplier of 277.778 kWh per GJ this is equivalent to BC Hydro offering $41.667 per GJ of electricity made from raw Biogas. Assuming 90% efficiency of upgrading raw Biogas to Biomethane, the comparative alternative would be $37.500 per GJ of Biomethane, and given the above conversion formula this works out to a competitive alternative at $30.830 per GJ of Biomethane delivered to a customer on the Terasen Gas distribution system. The Company has decided against proposing this alternative maximum unit price for Biomethane projects for the same

85 BCH F2011 RRA, Appendix A1, Page 3, Line 7
86 BC Hydro Bioenergy Phase 2 Call Request For Proposals, Page 2, Line 6. Accessed at http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/acquiring_power/2010q2/20100531_bioenergy.Par.0001.File.20100531_Bioenergy_Phase_2_RFP_.pdf on June 2nd, 2010.

reasons it is not proposing to use the Clean Energy rate of $0.13/kWh discussed in the above paragraph. However, Terasen Gas 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 to meet our customer's demands.

Another alternative proxy point considered was the South East False Creek District Energy System ("SEFCDES") rate for clean energy. This option was not pursued for several reasons. Firstly, this proxy might be less relevant as the SEFCDES only serves a small neighborhood of the City of Vancouver and is a high-end showcase development. Additionally, the SEFCDES rate was calculated in such a way as to initially use BC Hydro rates as a reference point, making a comparison to it rather than a BC Hydro rate a redundant comparison. Finally, the rate structure at the SEFCDES is different in nature from rates offered by larger scale utilities such as Terasen Gas and BC Hydro, and is thus much more difficult to draw comparisons to. For example, District Energy Systems ("DES") tend to have different rates than utilities that provide raw energy input, as customers do not have to include the costs of owning a furnace or other energy conversion devices in their price comparisons. In other words, DES rates could include more services and products offering than the typical price for services from the electricity or natural gas utilities.

A similar proxy to the SEFCDES rate is that charged by Dockside Green Energy ("DGE") in Victoria. DGE serves as another example of the premium customers are willing to pay for renewable, low carbon energy. Similar to SEFCDES, the DGE rate structure is a mix of a fixed amount for floor space and a variable amount for energy. Additionally, the DGE rate is charged to strata corporations, who then allocate the costs to individual strata unit owners, making a direct translation between energy consumption and cost more complex. Finally, similar to SEFCDES, DGE serves one small high-end neighbourhood, whereas Terasen Gas proposes to sell Biomethane throughout most of the province. For these reasons, DGE is a poor direct pricing proxy for Biomethane.

Terasen Gas also considered a cap involving a multiple of the existing natural gas commodity rate so as to set a fixed percentage premium over the incumbent price. A number of concerns caused this methodology to be rejected. Firstly, there is no relationship between the factors that drive the market that determines the price of conventional natural gas and the cost of service of producing Biomethane. Attempting to fix the cost of Biomethane to a multiple of the market price would therefore send distorted pricing signals to both producers and customers, and would unduly distort the relationship between these two products. Secondly, GHG neutral Biomethane is a fundamentally different product than conventional natural gas, so imposing a pricing relationship between the two would be difficult to justify.

Terasen Gas also considered proposing no cap on the unitized price of Biomethane. Since the Green Gas offering is fully optional for customers and they may leave it at any time, 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, the

Company 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.

In summary, the Company assessed five alternative methodologies for determining a maximum allowable unit cost of Biomethane, and found that, while each has relative strengths and weaknesses, using the BC Hydro Tier 2 Residential Rate is the superior option. The reasons behind this conclusion were that the BC Hydro Tier 2 Residential Rate is the only directly customer-observable comparison price for new renewable clean energy in British Columbia.

8.4.3 REGULATORY REVIEW OF NEW SUPPLY PROJECTS AND CONTRACTS

Future Biogas or Biomethane supply contracts will have to be filed with the Commission under section 71 of the UCA. Section 71 provides that the Commission may specify any further evidence that is required to determine whether a supply contract is in the public interest. Terasen Gas can also apply, as it has done in this Application, for section 44.2 approval. Terasen Gas believes that a streamlined regulatory review process is warranted in circumstances where the above guiding principles are met. As such, Terasen Gas is proposing that a streamlined process be applied in cases where the supply contracts meet specified criteria.

The proposed streamlined process is that Terasen Gas will file only the supply contract for acceptance under section 70, with no additional supporting information. Terasen Gas would choose not to apply for approval pursuant to section 44.2.

The criteria Terasen Gas is proposing for this streamlined process for future Biogas and Biomethane supply contracts are as follows:

1. The projected supply meets the proposed economic test discussed in Section XX above, with the maximum price for delivered Biomethane on the system re-calculated from time to time based on updates to the BC Hydro RIB Step 2 Rate;
2. The supply contract is at least 10 years in length;
3. Terasen Gas has, by agreement, retained final control over injection location;
4. Terasen Gas is satisfied that the upgrade technology is sufficiently proven;
5. Terasen Gas has, by agreement, reserved the right to refuse gas if customer safety or asset integrity is at stake;
6. The partner is a municipality, regional district or other public authority, or is a private party with a track record in dealings with the Company or that posts security to reduce risk of stranding.

8.4.4 POST IMPLEMENTATION REVIEW

In requesting approval of the streamlining of the development of Future Supply and Tariff Offerings, the Company acknowledges that a thorough review of the Green Gas program's success will be necessary in the future. Terasen Gas proposes that the approved Green Gas program be reviewed through a post implementation report and workshop, both occurring five years after the launch date of the Residential Green Gas program (targeted to be launched in October of 2010). The report and workshop will address how many and what types of supply projects have been developed, customer segmentation, enrolment and attrition rates as well as address and review the costs incurred, and the recovery thereof.

This timeline should allow the Company adequate time to validate our research into the Residential and Commercial markets, and to develop additional supply projects to help this industry mature. In the meantime, Terasen Gas proposes to report on the development of the Green Gas program through its Revenue Requirement Applications related to the end to end business model and report the Biomethane gas cost as part of the quarterly gas cost reporting that is established with the Commission.

8.5 Essential Services Model (ESM) Stays Intact

While there are some substantial differences between the Terasen Gas Standard Rate and the Green Gas offering, the ESM and its design will remain unchanged. Under the ESM, customer enrolments for Gas Marketers and the Terasen Gas Standard Rate offering determine the allocation of gas supplied to the Midstream infrastructure at the three supply hubs (15% Huntington, 15% AECO, and 70% Station #2). This total supply is based on normalized annual demand for Rate Schedule 1 through 7 customers. This supply is supplied into the Midstream at 100% load factor and parties have the ability to replace this supply should supply problems occur. This is different from how the Biomethane volumes will be produced and managed. Biomethane volumes will have a fluctuating supply curve with no ability to replace supply should the production facilities fail. Therefore, the Biomethane supply will not be able to be considered part of annual base load and must be managed differently from base load gas, thus necessitating the management of Biomethane in the Midstream. The impact of the Biomethane supply will be reviewed annually as part of the Annual Contracting Plan performed by Terasen Gas. Given the supply from the two projects identified in this Application there is no impact or changes that need to be made to the resources that make up the Annual Contracting Plan. As mentioned above, the impact of future supply will be addressed yearly as part of the Annual Contracting Plan process.

8.6 Conclusion

The flexible approach to future supply projects that Terasen Gas is proposing is similar in structure to the model for electric generation within the Province. In the case of both of the major electric utilities, BC Hydro and FortisBC, some of the electricity commodity is produced from generation assets that are owned and maintained by the utility and other supply is purchased from Independent Power Producers contracts whereby the supplier invests in the generation equipment. The models being proposed are also akin to what is currently used in the production of traditional natural gas supply. Additionally, the ESM and its design will remain unchanged as a result of the way the structure of this supply model has been developed. Terasen Gas believes that the approach set out in this Section is in the best interests of customers at this time.

9 BIOMETHANE SUPPLY PROJECTS INCLUDED IN THIS APPLICATION

9.1 Introduction

In this Application, Terasen Gas is submitting two supply projects for the Commission's consideration. Both projects will use raw Biogas as an input gas which will be upgraded to meet pipeline quality Biomethane. They represent concrete examples of the two supply models outlined in Section 8.

- The first project is at a landfill in Salmon Arm, BC. The project partner is the Columbia Shuswap Regional District ("CSRD"). In this project Terasen Gas is purchasing raw Biogas and investing in upgrading equipment, along with the distribution main and interconnection facilities, which includes gas quality monitoring, pressure regulation and odorizing.
- The second project is an agricultural waste to Biomethane project located in Abbotsford BC. The project partner is Catalyst Power Incorporated ("CPI"). In this project, Terasen Gas is acting as a purchaser of upgraded Biomethane with a relatively small capital investment in distribution main and interconnection facilities, which include gas quality monitoring, pressure regulation and odorizing. The project partner has been able to satisfy Terasen Gas that it will be in a position to produce a reliable and consistent supply of upgraded Biomethane.

The justification for these projects is covered in prior sections of this Application. The Company believes that both of these projects will deliver a safe and reliable supply of Biomethane to the existing Terasen Gas distribution system, at a cost that falls within the economic parameters outlined in Section 8.4.2.1. They provide a suitable basis for launching the Green Gas offering.

This Section is organized as follows:

A) Salmon Arm Project Application

B) Catalyst Project Application

C) Early Supply Benefits

These topics are discussed in detail below.

9.2 Salmon Arm Project

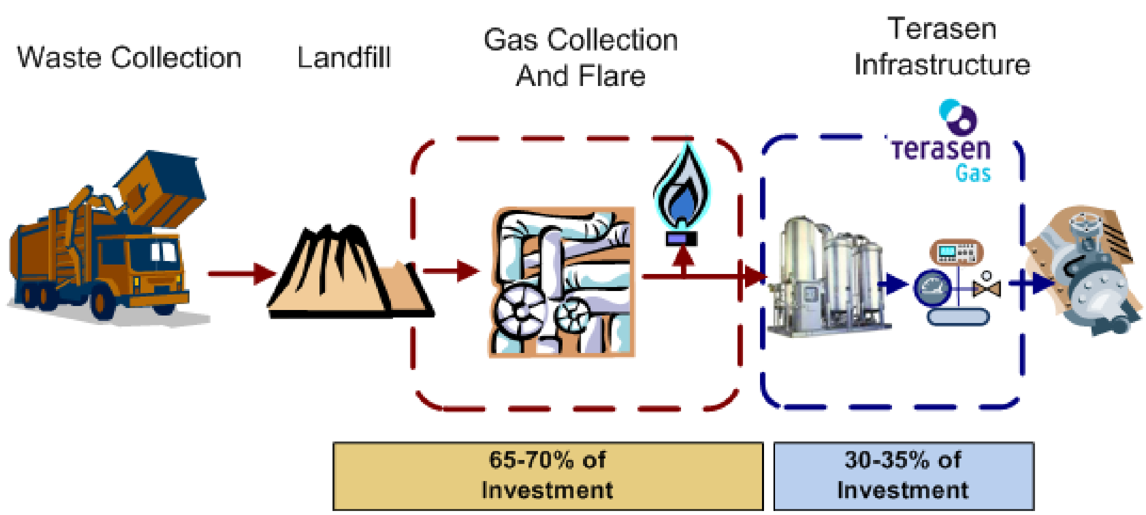
With this Application, Terasen Gas seeks approval, in accordance with Section 71 of the Act, of an Energy Purchase Agreement between Terasen Gas and the CSRD for the purchase of Biogas (the "CSRD Agreement") and section 44.2 approval for the proposed investment of

$2,304,400, less government funding ($515,600) for a total estimated cost of $1,788,800, on the facilities required to upgrade Biogas, measure the flow of gas, connect to Terasen Gas distribution infrastructure and to ensure that the Biogas quality meets Terasen Gas pipeline specifications. This Project represents a significant early step in the development of Biogas upgrading as a new source of renewable energy supply in British Columbia.

9.2.1 OVERVIEW

The CSRD indicated an interest in a beneficial use for landfill gas in response to the Terasen Gas Biogas "Request For Expressions Of Interest" ("RFEOI") in 2009. The Biogas project will be located at the regional landfill within the city limits of Salmon Arm, BC. In this case, Terasen Gas will invest in, construct and own the Biogas upgrading equipment, as well as installing connection to the main and associated metering, monitoring and gas control equipment on-site. Raw Biogas will be collected by CSRD and delivered to Terasen Gas on the landfill site. CSRD is investing approximately $4,800,000 to install the landfill gas ("LFG") capture, collection and flare system. The relative investments are illustrated below in Figure 9-1.

Figure 9-1: Investment Structure of CSRD Project



Terasen Gas will use proven technology to upgrade the raw landfill Biogas to produce pipeline quality Biomethane. The Biomethane will be injected into the existing Terasen Gas distribution system. The injected Biomethane is expected to displace the quantity of natural gas required to serve more than 300 households[87] annually, and thus reduce GHGs by approximately 1,500 tonnes annually by displacing conventional natural gas.

Terasen Gas has been in discussions with the CSRD for almost a year regarding this project, during which CSRD has developed a construction plan and engaged engineering resources for the landfill gas collection facilities. Commission approval for this contract is necessary at this

87 Based on North Okanagan typical annual household demand of 100 GJ.

time to ensure that upgrading facilities to accept raw gas and the CSRD Agreement are in place so that gas can be purchased by Terasen Gas upon start-up of the CSRD facilities.

9.2.2 KEY PROVISIONS OF THE SUPPLY AGREEMENT

The current agreement between CSRD and Terasen Gas is summarized in the following sections. The detailed terms of the agreement are confidential, and the agreement has been filed under separate cover as Confidential Appendix I-1 Terasen Gas believes that confidentiality of this information is necessary in order to protect the Company's ability to negotiate future Biogas purchase contracts with producers on the best possible terms for customers.

Quantity

The supply agreement provides for an expected daily delivery quantity of the equivalent gas required to produce 85 GJ per day of processed pipeline quality Biomethane. This quantity is equal to annual delivery of approximately 30,000 GJ. This is below the expected annual maximum flow that can be received on the distribution system based on analysis that was done on demand downstream of the interconnection location.

Term

The Term of the agreement is 15 years, with a yearly automatic renewal after the first fifteen years.

Price

The commodity price that Terasen Gas has agreed to pay CSRD for raw Biogas is provided to the Commission in Confidential Appendix I-1.

The commodity rate agreed to by Terasen Gas and the CSRD is the result of negotiations with the CSRD. The commodity price falls within the range of expectation based on the Company's experience to date with Biogas proposals and in reviewing Biogas development programs in other jurisdictions. It falls within the range proposed as an economic test for future review of projects.

Quality

The agreement commits the CSRD to meet a raw gas quality specification. This raw gas specification, combined with the Terasen Gas upgrading equipment, will ensure that Terasen Gas' quality specifications for Biomethane are met. The specifications are identified in Schedule C of the CSRD Agreement, found in Confidential Appendix I-1.

Other

The CSRD Agreement and the Terms and Conditions set out the requirements for each party to deliver and receive minimum and maximum amounts of Biogas. CSRD is required to make commercially reasonable efforts to maintain equipment and supply the best quality gas possible as an input to the Terasen Gas upgrading plant. In addition, the agreement requires CSRD to provide projected gas quantities for planning purposes and to provide notice of supply interruption for planned maintenance. In general, the agreement strikes a balance between commitment to deliver and perform while allowing both entities sufficient flexibility to solve minor operational issues which may arise.

The CSRD Agreement gives Terasen Gas license to enter the site, install, operate, maintain and remove any equipment necessary to ensure Biogas quality is maintained and accept Biogas as required by the agreement.

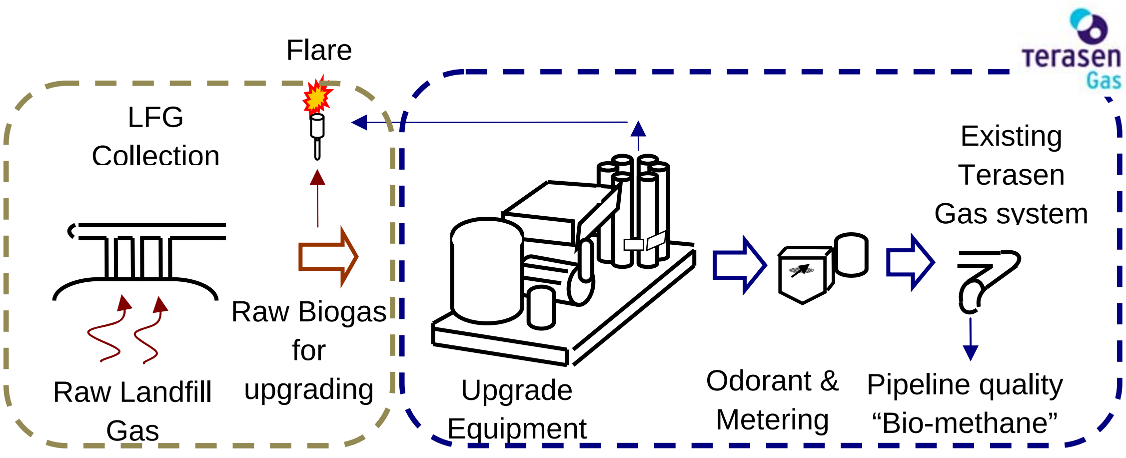
9.2.3 DESCRIPTION OF FACILITIES ADDITION

The CSRD will design, install and operate a LFG collection system on the landfill site with a physical address of 4290 20 Ave S, Salmon Arm, BC. Terasen Gas will design, install and operate an upgrading plant and receive LFG on the landfill site. Terasen Gas will also install connection to the existing distribution system located in the municipal right-of-way and connect to the upgrading facility through a metering, monitoring and odourizing station. The proposed system tie-in point is immediately adjacent to the landfill access road (See Figure 9-2).

Figure 9-2: Connection point to Terasen Gas System

The schematic in Figure 9-3 provides a simplified overview of the interconnection of the Biogas production and processing facilities with the natural gas distribution system.

Figure 9-3: Schematic Biogas plant Project Responsibilities



Terasen Gas' upgrade equipment and metering facilities will ensure the quality and consistency of Biomethane supplied to the distribution system. As the assurance of quality from this project is confirmed to remain steady over time, this additional monitoring equipment might be able to be removed from the site and redeployed to another Biogas project once this flow rate is confirmed.

In addition to the gas meter that will measure the quantity of Biomethane delivered and the quality monitoring equipment, Terasen Gas will need to blend odourant with the delivered Biomethane before it enters the natural gas distribution system. The odourant is required as a means of leak detection since at times a number of customers will receive natural gas that is produced primarily from the Biogas supply without being mixed with conventional supplies of natural gas which have already been injected with odourant.

Propane may also be required to be injected on occasion to assist with leak checking efforts as discussed above. A provision will be made in the design of the system to allow for propane injection when required.

Finally, a data connection to the Company's system-wide gas monitoring and control system has been included in the capital costs outlined in Section 9.2.5 below.

Interconnection of gas quality equipment on-site with the Company's gas control system will allow ongoing monitoring of Biomethane production and quality as well as an ability to shut off the supply from the CSRD instantly. As with the monitoring equipment itself, the gas control connection may be able to be removed and redeployed to another start-up Biogas project as confidence in the quality and consistency of Biogas from the CSRD project grows.

The gas main and connection to the existing distribution system will be located in the municipal road right-of-way. All other interconnection facilities and monitoring equipment will be located at the CSRD project site, downstream of the Biogas upgrading equipment. The CSRD Agreement contains conditions giving Terasen Gas license to enter the site for the installation, operation and maintenance of the Terasen Gas facilities.

It is expected that the equipment installed by Terasen Gas will have a lifetime that exceeds the contract term. The Company will evaluate whether or not to pursue a renewal of the contract at an appropriate time, which is as yet undetermined. In the event that an agreement to renew the contract term was not reached for any reason, Terasen Gas will remove and either re-purpose or liquidate the skid-mounted upgrading equipment and re-purpose the meter and gas analysing equipment.

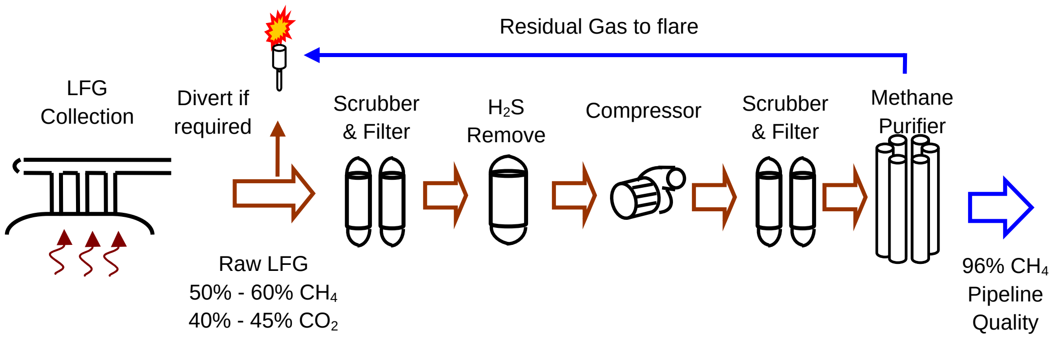
9.2.4 TECHNOLOGY SELECTION AT SALMON ARM

During the feasibility phase of the project evaluation, other technology providers were consulted to improve the quality of the equipment cost estimates for the financial model. For LFG upgrading, the removal of carbon dioxide (CO_2) is considered to be the most challenging and critical component to provide pipeline quality gas with an appropriate heating value. Terasen Gas has engaged Xebec to design, build and install the purification system for this project.

Xebec has sold a range of commercial rotary valve PSA products since the late 1990's, primarily for the purification of hydrogen-containing streams in on-site hydrogen generation plants, and systems that recover hydrogen from waste gas streams. In 2003 Xebec began marketing a range of products to recover pipeline-grade bio-methane from renewable methane sources such as landfill gas and anaerobic digester gas. At present, Xebec has PSA systems operating on landfill gas in Cincinnati, Ohio and on anaerobic digester gas generated from agricultural waste in Fennville (Michigan), Salzburg (Austria), and Widnau (Switzerland). In addition, Xebec has another 5 methane recovery systems currently being manufactured or installed at digester gas projects in Europe and North America.

The upgrade process can be summarized as contaminant removal, compression and CO_2 removal. A high level schematic of the process is included below in Figure 9-4.

Figure 9-4: Upgrade Process



Based on the comparison of technologies and initial cost estimates from suppliers of gas upgrading technology, it was found that the relative costs are within approximately 15% of each other. However, each technology has a different recovery rate of methane which will impact the amount of energy produced for a given initial capital investment. In the case of the Salmon Arm Project, the Xebec technology ranked second (when compared to water wash technology). The estimated 94% recovery of methane and a projected purity of 96% methane are comparable with the water wash technology (which had slightly better recovery estimated at 97%). However, by using Xebec, Terasen Gas was able to take advantage of approved government funding associated with the purchase of upgrade equipment specifically designed by this company, which made the Xebec option the most advantageous.

9.2.5 TERASEN GAS' COST

Terasen Gas has undertaken preliminary cost estimates for the facilities it will require in order to accept raw Biogas from the CSRD at this location. Table 9-1 provides an estimate of the installed capital costs for the facilities that Terasen Gas has identified will be needed in order to accept Biomethane from the CSRD at the landfill. The costs in the table include a contingency of 10%. Terasen Gas believes that a contingency of 10% is reasonable based on the fact that a large portion of the project cost is fixed (upgrading plant) and the remainder of the estimate was based on the actual costs of the Catalyst Project to date. The contingency is included in the figures shown below.

Table 9-1: 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**

Operating costs are estimated to be approximately $56,000 annually and consist primarily of electricity costs, filter and media replacement, odorant and inspections.

9.2.5.1 Supporting Information for Cost Estimate

Of the total costs, Terasen Gas is using a fixed price contract for the procurement of the upgrading plant. This portion of the costs accounts for approximately 60% of the project costs. The remaining costs are based on internal cost estimates from the engineering team responsible for delivering the project. The cost estimate for internal work is based on a bottom up approach. The estimate can be roughly divided into three remaining categories:

- The first category is the connection from the plant to the existing main in the street adjacent to the landfill. This estimate was based on standard buried pipe installation costs for the terrain and expected length of the pipe run;
- The interconnection facilities consists of the necessary equipment to regulate, odorize, meter and control gas flow. These facilities are located between the upgrading plant and the buried line to the main. The cost estimate was done by totalling costs of all of the required components and the estimated labour time which includes engineering, drafting, fabrication and testing; and
- The cost of monitoring gas quality is based on known price estimates for the required equipment. Finally, a contingency has been added to cover unexpected and unaccounted costs.

While preparing the cost estimate, Terasen Gas was able to duplicate much of the work already done for the Catalyst project. By doing so, the accuracy of the cost estimate is better because it is partially based on known procurement costs on a similar project.

9.2.5.2 Cost Contribution Reduces Cost to Terasen Gas

Terasen Gas was originally awarded money from the provincial government Innovative Clean Energy (“ICE”) fund in early 2009 for a proposed Biogas project at the Lion’s Gate Wastewater Treatment Plant. Though that project did not proceed as planned, the ICE fund staff have agreed to transfer the remaining undisbursed funds in the amount of $315,600 to the Salmon Arm Project.

In addition, Terasen Gas has been awarded $200,000 from the BC Bioenergy Network (BCBN) in direct support of this project.

Table 9-2: Capital Cost Summary with Funding

Item	2010 Estimate
Planned Costs	$ 2,304,400
Less ICE funding	315,600
Less BCBN funding	200,000
Total	**$ 1,788,800**

The capital costs and operating costs, net of the above contributions, are accounted for as a part of the cost of service model and will therefore be included in the final selling price of the Biomethane as part of the Green Gas offering.

9.2.6 GHG REDUCTION

The CSRD project will result in a reduction in GHG emissions because renewable Biomethane created from the upgrading of raw Biogas will be substituted for 30,000 GJ of conventional natural gas. The expected annual GHG emission reduction associated with this project is expected to be at least 1,500 tonnes of carbon dioxide equivalent gas (“CO_2e”) per year.

The calculation for annual CO_2e reduction is provided in Table 9-3 as follows:

Table 9-3: Annual CO2e 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

There will also be GHG emission reductions realized by the CSRD through the reduction of methane emissions that are released from the landfill that are not associated with the displacement of conventionally supplied natural gas. The CSRD will retain rights to any value from these additional emission reductions and will be responsible for the validation of these emissions reductions.

9.2.7 PROJECT SPECIFIC RISKS AND MITIGATION

A number of measures have been incorporated into both the agreement and the facilities themselves to mitigate a range of potential risk. From an operational perspective, we believe that the Project poses little risk to the system, and the steps taken to minimize operational and other risks are described below.

9.2.7.1 Risk to Gas Supply Portfolio

The quantity of Biogas from this single project will not impact the Company's overall gas supply portfolio. At this level of supply, entering this agreement with the CSRD will not cause Terasen Gas to alter its other portfolio planning practices or contracts. Therefore, on its own, the amount of Biogas promised in this agreement will not leave Terasen Gas vulnerable to either additional market purchases or access to alternative sources of conventional gas to replace Biogas that is not delivered. As additional Biogas purchase agreements come online and as confidence in the firm delivery of pipeline quality Biogas increases, Terasen Gas will reassess the impact on its overall portfolio.

9.2.7.2 Risk of failure to supply Biomethane

The composition of buried waste in a landfill is not fully predictable and therefore neither is the gas production from a landfill. As a result, there is the potential for an interruption in either the supply of raw gas or an interruption in the supply of Biomethane. The second situation may be the result of unexpected contaminants. Terasen Gas has mitigated these risks in two ways:

- First from a gas system perspective, planning will be done assuming that the Biogas is not available (thereby reducing the risk of undersupply to customers);
- From a financial perspective, the compensation for sale of gas is based on sellable gas (purified gas). CSRD will not receive any payments unless Terasen Gas can successfully upgrade the Biogas and successfully inject it into the distribution system. There is also a minimum supply requirement that if not met will trigger a contractual default.

The supply of gas is expected to continue to grow as more waste is added to the landfill.

9.2.7.3 Risk of Stranded Assets

Related to the risk of failure to supply is the potential for permanent termination of the contract that would leave the Company's installed facilities on the site idle. The licensing clause gives Terasen Gas permission to enter the site and physically recover its facilities after a specified period of non-performance. The majority of these facilities, including metering, gas sampling and analyzing, and odourant injection equipment could then be used in other projects. For the connecting pipe and interconnection facilities, which are unlikely to be recovered if such an event occurs after installation, Terasen Gas has the right to a termination payment in excess of the estimated value of the stranded assets and moving costs. This amount is defined as the greater of $90,000 or the previous two years of revenue paid to the CSRD for gas (compared to an estimated $45,100 for the abandoned connection). Terasen Gas expects this risk to be highest in the first year of operation because this is the year of the highest asset value and the performance of this project will not yet be well-characterized.

9.2.7.4 Operational and System Risk

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, the upgrading system will be designed to self-monitor for abnormal conditions and Terasen Gas, as owner of the upgrading equipment, will always have final control of the gas quality. In the case that Biomethane does not meet the required quality, Terasen Gas will immediately stop delivery to customers and evaluate the source of the issue in cooperation with CSRD. In addition, if the Biomethane does not meet the Terasen Gas specification, the Company is not obligated to pay for it. The agreement also requires the CSRD to operate the landfill gas collection system in a manner that optimizes use for pipeline quality gas.

9.2.7.5 Facilities Cost Risk

There is some risk that costs for the facilities could be higher than expected; however, the main extension has been estimated based on the Terasen Gas Installation Centre's best practices and initial engineering estimates for the interconnection and monitoring equipment have been conservative to mitigate this risk. Further, the cost estimate for Terasen Gas supplied facilities has been done by the same engineering team that did the estimate and procurement for the CPI project. The largest portion of the capital costs is the procurement of the upgrading plant from Xebec. In this case, Terasen Gas has negotiated a fixed price contract with Xebec. Terasen Gas has further addressed this risk by including a 10% contingency allowance on capital costs within the cost-of-service analysis. In all, Terasen Gas believes that cost variation risk is low and will be re-evaluated at the detailed design stage for the facilities.

9.2.7.6 Timing of Construction Risk

The CSRD is scheduling the completion of the LFG collection system for the fall of 2010 and would like to begin delivering gas to Terasen Gas in the winter of 2010. This timing creates a narrow construction timeline for the Company to install required facilities. Terasen Gas does not intend to undertake this installation until the summer of 2010 in order to delay any cost risk as long as possible. However, in order to have facilities ready at the same time as gas is available, construction procurement will have to start ahead of that time. Delays in the timeline could delay main installation connection and final site work into the winter season. In this case, there may be added costs and complications due to the weather in the region in the winter months.

9.2.8 LAND TENURE

The main extension to connect Biogas to the distribution system will run in existing right-of-way within the City of Salmon Arm. License to Terasen Gas to enter the land for the installation, operation, maintenance and removal of equipment is provided by CSRD. Neither the agreement nor the facilities involve crown land.

9.2.9 OTHER PERMITS AND APPROVALS REQUIRED BY TERASEN GAS

Terasen Gas has made an assessment of other permits and approvals that will be required by for the facilities. As described below, does not anticipate that these will pose a hindrance to the installation and operation of the equipment proceeding.

The Company's project manager will ensure compliance to all regulating authorities for the Terasen Gas portion of the project.

Construction of the main will take place within the right-of-way of city roads and will be undertaken pursuant to the Company's existing tariff and current best practices for the installation of gas mains. Terasen Gas has reviewed the proposed main location and does not anticipate any impediments to installation.

9.2.10 CONSULTATION

Terasen Gas has specifically requested the CSRD provide notification of outstanding claims or First Nations concerns regarding this project. The CSRD has indicated that there are no outstanding claims or concerns in the planned project area.

The Company's Community and Aboriginal Relations group has also evaluated the project. There are no existing claims in the area and no outstanding issues. The project will take place on city-owned land, including the landfill. For further discussion of First Nations consultation, see Section 12.5.

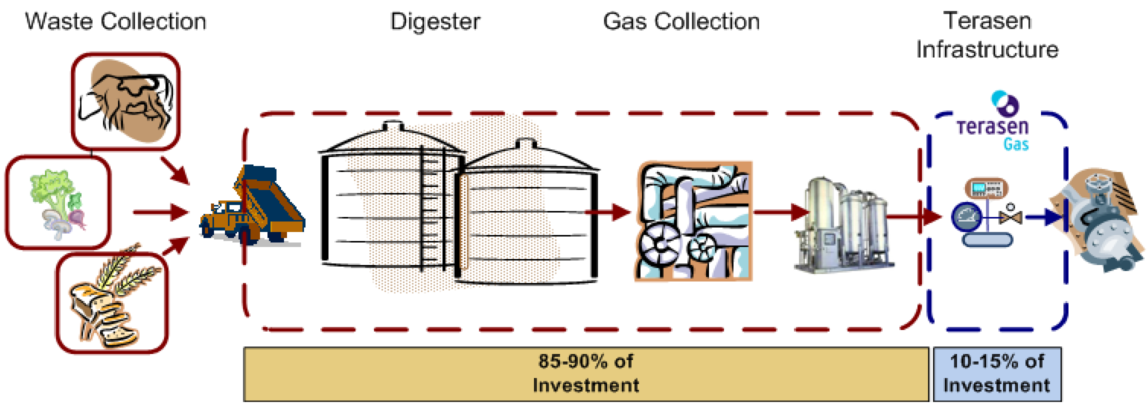
9.3 Catalyst Project

With this application, Terasen Gas seeks approval, in accordance with Section 71 of the Act, of an Energy Purchase Agreement between Terasen Gas and CPI to purchase Biomethane (the "CPI Agreement") and approval to spend $587,700 on the facilities required to measure the flow of gas and to ensure that the Biogas quality meets Terasen Gas pipeline specifications. This Application represents a significant early step in the development of Biogas upgrading as a new source of renewable energy supply in British Columbia.

9.3.1 OVERVIEW

CPI is investing capital in the digestion, gas collection and upgrade technology as part of this project (estimated at approximately $5 million). Based on estimates provided by the project developer, the portion of investment provided by Terasen Gas is approximately 10-15% of the Biogas project costs and includes a main extension. The conceptual arrangement is shown below in Figure 9-5.

Figure 9-5: Investment Structure of CPI Project



CPI will use innovative technology to produce raw Biogas through anaerobic digestion of organic waste materials from agriculture and upgrade that raw Biogas to produce pipeline quality Biomethane, which will then be injected into the Company's distribution system. The injected Biomethane is expected to displace the quantity of natural gas required to serve more than 875 households annually, and thus reduce GHG emissions by at least 4,000 tonnes annually based on the minimum projected supply. [88] The projected likely Biomethane production will result in further reductions in GHGs.

Terasen Gas has been in discussions with CPI for over a year regarding this project, during which CPI has acquired financing, raised the necessary capital and completed a host of municipal and provincial regulatory applications, including receiving funding from the Provincial Innovative Clean Energy ("ICE") fund.

The BC Government has indicated its support for the CPI Biogas and upgrading project through an Innovative Clean Energy ("ICE") fund award of $1.5 million to CPI. The CPI ICE funding application specifically identified Biogas upgrading and pipeline injection in the project design.

> *The mandate of the ICE Fund is to accelerate the development of new energy technologies that have the potential to solve real, everyday energy and environmental issues and create significant socio-economic benefits for all British Columbians[89].*

CPI's success in the ICE Funding process is a strong indication of the Government's support of the Project. Only 15 of 60 projects applying to the ICE Fund's first call process were successful.

Commission approval for this contract is needed at this time to ensure that the CPI Agreement is in place and gas can be purchased by Terasen Gas upon start-up of the CPI facilities. Delays

[88] Based on Lower Mainland typical annual household demand of 95 GJ.
[89] INNOVATIVE CLEAN ENERGY FUND Program Information & Application Guidelines, p.3.

in the regulatory process will put pressure and expense on CPI's financing and partnership arrangements, potentially putting the project at risk.

9.3.2 KEY PROVISIONS OF SUPPLY AGREEMENT

The current agreement between CPI and Terasen Gas is summarized in the following sections. The detailed terms of the agreement are confidential, and the agreement has been filed under separate cover as Confidential Appendix I-2. Terasen Gas believes that confidentiality of this information is necessary in order to protect the Company's ability to negotiate future Biogas purchase contracts with producers on the best possible terms for customers.

Quantity
The supply agreement provides for a minimum daily delivery quantity of 230 GJ per day of processed pipeline quality Biomethane. This quantity is equal to annual delivery of 84,000 GJ. If CPI can produce more than 230 GJ per day, Terasen Gas has agreed to accept up to 500 GJ per day, which is the maximum flow that can be received on the distribution system based on demand downstream of the interconnection location during low flow (summer) periods.

Term
The Term of the agreement is 10 years.

Price
The commodity price that Terasen Gas has agreed to pay CPI for pipeline quality Biomethane is provided to the Commission in a Confidential Appendix I-2

The commodity rate agreed to by Terasen Gas and CPI is the result of negotiations with CPI. This amount has been taken into account by CPI in determining its development and business costs and achieving an acceptable rate of return for its investments. The commodity price falls within the range of expectation based on the Company's experience to date with Biogas proposals and in reviewing Biogas development programs in other jurisdictions.

Quality
The agreement commits CPI to meet Terasen Gas quality specifications. The specifications are identified in Schedule D of the CPI Agreement in Confidential Appendix I-2.

Other
The CPI Agreement and the Terms and Conditions set out the non-performance definition for each party to deliver and receive minimum and maximum amounts of Biomethane. The non-performance definition and excuse from non-performance for maintenance in the agreement strike a balance between committing both CPI and Terasen Gas to deliver and accept pipeline quality Biomethane and allowing both companies sufficient flexibility to solve minor operational issues which may arise.

Various sections of the agreement spell out an 'event of default' and remedies for either party in such an event. The CPI Agreement gives license to Terasen Gas to enter the site, install, operate, maintain and remove any equipment necessary to ensure Biomethane quality is maintained and accept Biomethane as required by the agreement.

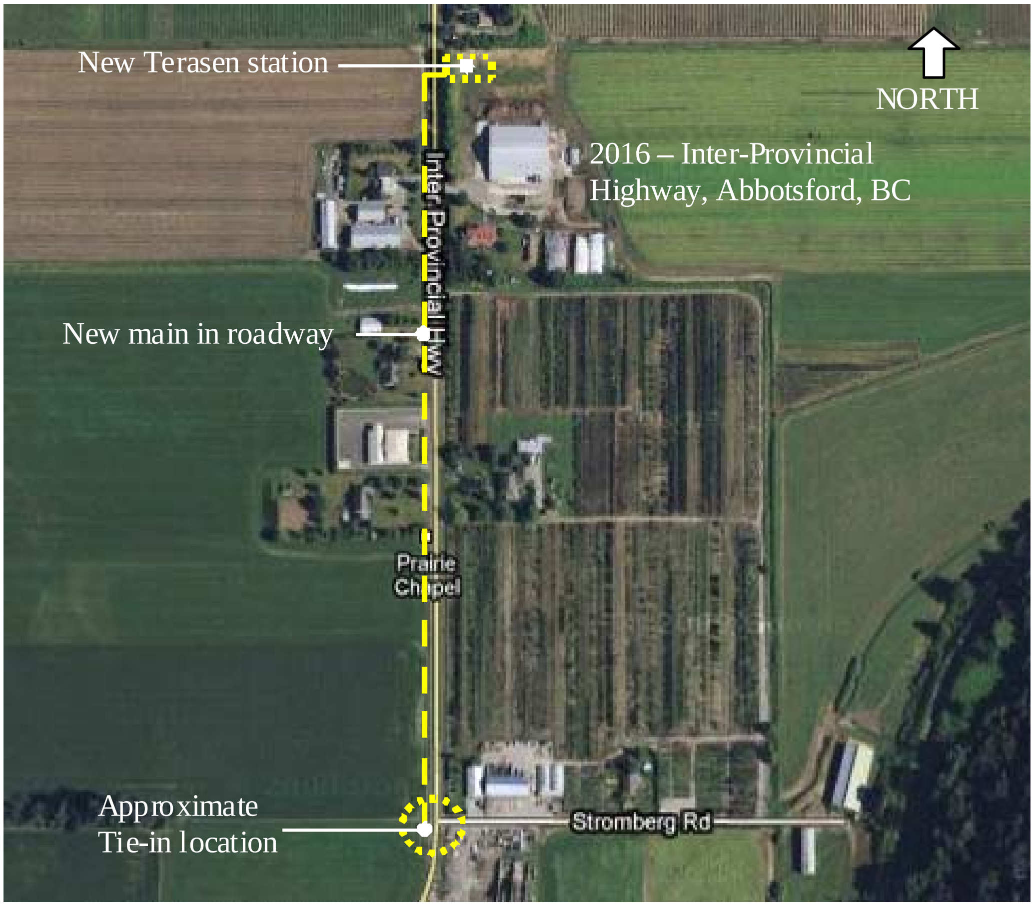
The CPI Agreement includes the requirement for a letter of credit that can be drawn on by Terasen Gas to cover costs for the bulk of non-recoverable assets in the event that the agreement is terminated once the assets have been placed. Non-recoverable assets are primarily the main extension to the Company's distribution system since other measuring and monitoring equipment can be removed and used elsewhere.

9.3.3 DESCRIPTION OF FACILITIES ADDITION

CPI intends to utilize farm based, organic waste materials, supplemented by other high energy organic waste materials in an anaerobic digestion process to produce raw Biogas. In this case, CPI is the developer of the anaerobic digester project and would prefer to invest in the upgrading equipment as well. Therefore, Terasen Gas is not constructing, owning or operating the Biogas upgrading equipment for this project.

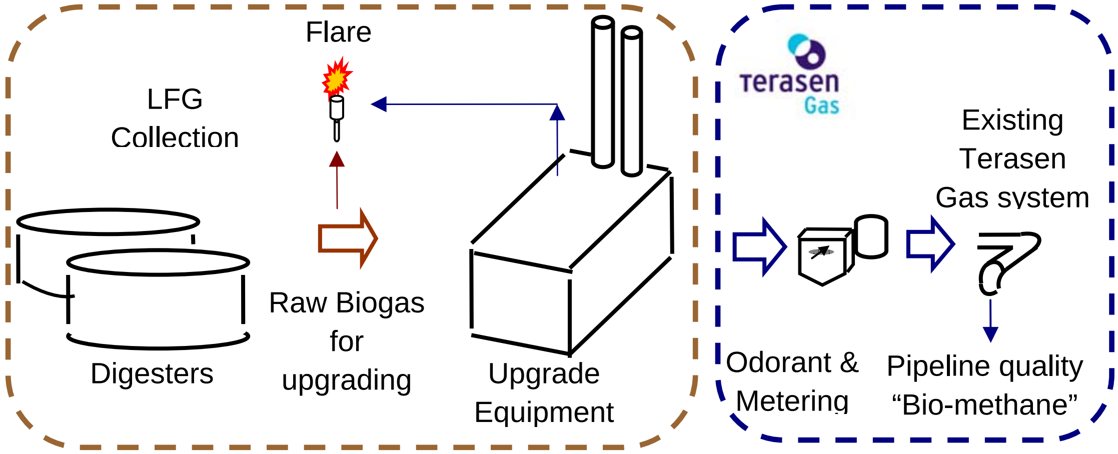
CPI will transfer the upgraded Biomethane to Terasen Gas on the site where the digester and upgrading facilities are located (2016 Inter-Provincial Highway in Abbotsford). Terasen Gas must construct pipeline main and monitoring facilities on the site and along the municipal right-of-way to a point of connection with Terasen Gas' existing distribution system, 760 meters south of the site (see Figure 9-6).

Figure 9-6: Connection Point to Terasen Gas Distribution System



The schematic in Figure 9-7 which follows provides a simplified overview of the interconnection of the Biogas production and processing facilities with the natural gas distribution system.

Figure 9-7: Schematic of Biogas Production, Upgrading and Pipeline Injection



The Company is installing additional monitoring equipment and controls to ensure the quality of the Biomethane that Terasen Gas is taking into its distribution system. This installation will help Terasen Gas confirm the quality and consistency of Biomethane that will be provided by agricultural anaerobic digestion projects. As the assurance of quality from this project is confirmed, this additional monitoring equipment might be able to be removed from the CPI site and redeployed to another Biogas project start-up. The cost of this equipment is included in the cost of service model for the life of the Agreement to provide a conservative approach to project costs.

In addition to the gas meter that will measure the quantity of Biomethane delivered and the quality monitoring equipment, Terasen Gas will need to blend odourant with the delivered Biomethane before it enters the natural gas distribution system. The odourant is added (similar to natural gas) to ensure that Biomethane leaks can be detected in the same manner as natural gas leaks. Propane may also be required at times to allow the use of chemical leak detection devices which also search for these minor constituents in order to distinguish pipeline methane from natural sources in the environment.

Similar to the CSRD project, a data connection to the Company's gas control system has been included in the capital costs outlined below. Interconnection of the additional quality monitoring equipment with Terasen Gas' control system will allow ongoing monitoring of Biogas production quality and the ability to shut off the supply from CPI on short notice if the upgraded gas does not meet the pipeline quality specifications set out in the purchase agreement. As with the monitoring equipment itself, the connection may be able to be removed and redeployed to another start-up Biogas project as confidence in the quality and consistency of Biomethane from the CPI project grows.

The gas main and connection to the existing distribution system will be located in the municipal road right-of-way. All other interconnection facilities and monitoring equipment will be located at the CPI digester project site, downstream of the Biogas upgrading equipment. The CPI Agreement contains conditions giving Terasen Gas license to enter the site for the installation, operation and maintenance of the Terasen Gas facilities.

9.3.4 TERASEN GAS' COST

Terasen Gas has undertaken preliminary cost estimates for the facilities it will require in order to accept upgraded Biomethane from CPI at this location. Table 9-4 provides an estimate of the installed capital costs for the facilities that Terasen Gas has identified will be needed in order to accept Biomethane from CPI at this location. Terasen Gas has taken the approach of including a 20% contingency on capital costs for this analysis due to the nature of Biogas projects being new to the Company and the CPI project is the first of the projects. The contingency is included in the figures shown below.

Table 9-4: 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**

Operating costs are estimated to be approximately $33,000 annually and include the supply of odourant and propane as described above in operational risk. These costs are accounted for as a part of the cost of service model and will therefore be included in the final selling price of the gas.

Cost inputs for the CPI interconnection cost-of-service model are the commodity price agreed to in the CPI Agreement, the capital costs outlined in Table 9-4, and the operating costs presented above.

The initial project cost estimate for the Catalyst project was done using a bottom up approach. The three broad categories of the budget include the main extension costs, the interconnection costs and the quality monitoring costs:

- The main extension costs are based on standard main construction costs that use per meter costs associated with the local conditions (main location);
- The interconnection costs are based on the system interconnection facility design. The major components of the equipment were itemized and summed up to provide a final estimate along with engineering, drafting, fabrication and testing costs;
- The remaining cost category is based on the projected costs of the quality monitoring equipment. This cost was estimated by contacting vendors of the required monitoring equipment.

At the time of this application, much of the project costs for the Catalyst project have been committed. The current projected total project costs are on budget.

9.3.5 GHG REDUCTION

The Biomethane supplied by the CPI Project will result in a reduction in GHG emissions because it will be substituted for 84,000 GJ of conventional natural gas. The expected annual GHG emission reduction associated with the CPI Agreement is between 4000 and 9000 tonnes of CO_2e per year.

The calculation for annual CO_2 reduction is provided in Table 9-5 as follows:

Table 9-5: 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

There will also be GHG emission reductions realized by the agricultural community through the reduction of methane emissions that are released through traditional agricultural waste management practices and that are not associated with the displacement of conventionally supplied natural gas. CPI will retain rights to any value from these additional emission reductions and will be responsible for their validation.

9.3.6 PROJECT SPECIFIC RISKS AND MITIGATION

A number of measures have been incorporated into both the agreement and the facilities themselves to mitigate a range of potential risk. From an operational perspective, the Company believes that the Project poses little risk to the system, and the steps taken to minimize operational and other risks are described below.

9.3.6.1 Risk to Gas Supply Portfolio

The quantity of Biomethane from this single project will not impact the Company's overall gas supply portfolio. At this level of supply, entering this agreement with CPI will not cause Terasen Gas to alter its other portfolio planning practices or contracts. Therefore, on its own, the amount of Biomethane promised in this agreement will not leave Terasen Gas vulnerable to either additional market purchases or access to alternative sources of conventional gas to replace Biomethane that is not delivered. As additional Biomethane purchase agreements come online and as confidence in the firm delivery of pipeline quality Biomethane increases, Terasen Gas will reassess the impact on its overall portfolio. Further, the agreement includes the full costs of replacement gas in the non-performance remedies within the agreement.

9.3.6.2 Risk of Failure to Supply Biomethane

Failure of CPI to provide gas to Terasen Gas could result from events such as loss of waste stream supplies (anaerobic digester feedstock), failure to meet gas specifications, breach of contract (selling to an alternative buyer) or poor financial health resulting in interruption to operation. Terasen Gas has addressed these risks through a non-performance clause in the agreement. This clause includes a penalty substantial enough to deter CPI from selling to an alternative buyer and to ensure that CPI manages its feedstock contracts and system operations appropriately.

9.3.6.3 Risk of Stranded Assets

Related to the risk of failure to supply is the potential for permanent termination of the contract that would leave the Company's installed facilities on the site idle. The licensing clause gives Terasen Gas permission to enter the site and physically recover its facilities after a specified period of non-performance. The majority of these facilities, including metering, gas sampling and analyzing, and propane and odourant injection equipment could then be used in other projects.

For the connecting pipe and interconnection facilities, which are unlikely to be recovered if such an event occurs after installation, Terasen Gas is requiring a formal letter of security in the amount of $103,000. Terasen Gas expects this risk to be highest in the first year of operation.

9.3.6.4 Operational and System Risk

There remains the potential for failure of the Biogas upgrading equipment such that contaminants harmful to the pipeline or disruptive to customer service could occur. Terasen Gas has mitigated this risk by requiring the delivered Biomethane to meet the same specifications that are used for Terasen Gas natural gas supply (the gas specification is included as Schedule A of the CPI agreement) and including the right to interrupt delivery of Biomethane from the project if the gas does not meet the quality specifications set out in the agreement. The facilities will also be linked with the Company's gas control system to allow real time monitoring of the quality sampling equipment that will be installed and quick response in shutting off the delivery of Biomethane should quality problems arise. The pressurized flows of conventional natural gas in the distribution system will automatically backfill and replace the lost flow of Biomethane during such a stoppage. In this way, an interruption in Biomethane deliveries will not adversely affect the distribution system operation. An extended shut down may require adjustment of the nearest gate station to optimize system pressure.

9.3.6.5 Facilities Cost Risk

There is some risk that costs that the facilities cost could be higher than expected; however, the main extension has been estimated based on Terasen Gas Installation Centre's best practices and initial engineering estimates for the interconnection and monitoring equipment have been conservative to mitigate this risk. Terasen Gas has further addressed this risk by including a 20% contingency allowance on capital costs. As a result, Terasen Gas believes that cost risk is low and will be re-evaluated at the detailed design stage for the facilities. While Terasen Gas will work to ensure that costs are minimized during this project, the 20% contingency recognizes that this is among the first Biogas to pipeline projects to be installed on the Terasen Gas distribution system and provides a sufficient buffer for cost uncertainty.

9.3.6.6 Timing of Construction Risk

CPI's desire to begin delivering gas to Terasen Gas in the second quarter of 2010 creates a narrow construction timeline for Terasen Gas to install the main. The Company does not intend to undertake this installation until substantial construction of CPI facilities is demonstrated; however, delays in construction could push timing of the main installation into the winter season and cause further delays as a result. This risk will need to be balanced against the potential costs that extended construction delays through the winter period could cause to CPI.

9.3.7 LAND TENURE

The main extension to connect Biogas from the CPI Biogas site, owned by Chris and Hiromi Bush, to the Company's existing distribution system will run along Inter-Provincial Highway. License to Terasen Gas to enter the land for the installation, operation, maintenance and removal of equipment is provided by the landowners, who are also the majority owners of CPI. Inter-provincial Highway is identified in Abbotsford's Official Community Plan as a municipal collector road. Neither the agreement nor the facilities involve crown land.

9.3.8 OTHER PERMITS AND APPROVALS REQUIRED BY TERASEN GAS

Terasen Gas has made an assessment of other permits and approvals that will be required by Terasen Gas for the facilities and, as described below, does not anticipate that these will pose a hindrance to the installation and operation of the equipment proceeding.

Since CPI will be the owner and operator of the upgrading equipment and will be supplying Biomethane at pressures not greater than 100 psig, CPI will be required to obtain any approvals associated with the construction and operating of the upgrading equipment.

A building permit must be obtained from the City of Abbotsford, which handles building code compliance on its own behalf. CPI has applied for a building permit for the construction of the facilities it requires, including the building that Terasen Gas expects will house its interconnection and monitoring equipment. It was determined that a separate building permit is not required for the Terasen Gas facilities.

Construction of the main will take place within the right-of-way of Inter-Provincial Highway and will be undertaken pursuant to Terasen Gas' existing tariff and current best practices for the installation of gas mains. Terasen Gas has received approval to locate the main in the planned location. A local drainage ditch has been identified as a potential environmental concern for which Terasen Gas has developed and will implement its best practices in both obtaining necessary approvals and in undertaking construction activities.

9.3.9 CONSULTATION

CPI has conducted significant public consultations 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. The Terasen Gas work, however, is limited to a main extension and installation of gas quality and quantity monitoring and interconnection facilities. As a result, the consultation for this project is similar to that required to connect a new customer under its existing tariff and operating permits. Both CPI and Terasen Gas consultation activities are described below.

The CPI project site is located within the Agricultural Land Reserve ("ALR") of BC's Fraser Valley, in the City of Abbotsford. Currently, this type of energy production within the Agricultural Land Reserve in BC is considered a non-farm use and requires approval from the Agricultural Land Commission ("ALC"), which CPI has received. As part of these requirements, the ALC must also approve the importing of agricultural wastes from other nearby farms as a feedstock for the digester. The ALC approval process sets out requirements for public notification and consultation, including the requirement to address local municipal policies and bylaws regarding land use on agricultural land.

CPI also required a municipal zoning by-law amendment from the City of Abbotsford to construct and operate its proposed facilities. The City's zoning amendment process sets out requirements for public notification and a public hearing before City Council in which neighbours, members of the public and representatives of First Nations are invited to participate. CPI has met these requirements and obtained the necessary zoning bylaw amendment. The public hearing was conducted in August 2009, at which time the City's Council heard from neighbours of the CPI project site and other interested parties. The requested amendment was subsequently granted in September. CPI has also advised that it has received a building permit from the City of Abbotsford to begin construction of its Biogas facilities.

In February, 2009, CPI presented their Biogas production project proposal to the Agricultural Advisory Committee of the Fraser Valley Regional District. This presentation resulted in letters of support written to the ALC and the Province of BC.

The CPI Biogas facility will be accepting and managing organic waste materials in order to produce Biogas within its anaerobic digestion process. As such, the BC Ministry of Environment

("MOE") and the Fraser Valley Regional District ("FVRD") also require an amendment to the Region's Waste Management Plan ("WMP") in order to designate the CPI Biogas facility as part of that plan. Amendments to the Waste Management Plan also entail a public and First Nations consultation process. Typically this process involves notification and a public meeting to which community members, including First Nations representatives, are invited. FVRD has advised Terasen Gas, however, that given the extent of the consultation undertaken by the ALC and the City of Abbotsford, it undertook a limited consultation approach to the WMP amendment, providing notice of the proposed amendment and seeking written comments from members of the public and First Nations.

MOE has advised that it also has a consultation process that must be met as part of the WMP amendment process. This process also takes approximately one month and may run concurrently or subsequent to the FVRD public notification process. In addition to recommending referrals to a host of provincial and regional authorities, the MOE consultation process recognizes the government's responsibility to avoid unjustifiable infringements of aboriginal treaty rights and conduct First Nations consultation in accordance with the provincial policy for consultation with First Nations. As part of its application to amend the FVRD WMP, CPI has submitted a summary of its consultation activities related to its proposed Biogas production facility to date.

Terasen Gas has conducted stakeholder consultation with regard to its overall Biogas initiative. This consultation is described in Section 12 of this Application.

9.4 Anticipated Learnings

Terasen Gas is expecting these two initial projects, as well future supply projects, to provide benefits for our customers by providing them with a renewable energy source and by using the energy form in an efficient manner. These benefits are discussed in Sections 2 and 3. In addition, however, there will be technical lessons learned specifically related to the upgrading process, and Terasen Gas will gain a better understanding of the reliability of the Biomethane supply and operational feedback on items such as actual maintenance costs. These latter items are discussed below.

9.4.1 IMPROVED TECHNICAL UNDERSTANDING OF BIOGAS UPGRADING

The projects are expected to build on technical 'lessons learned', including:

1. Validation of the performance of upgrading technology. The first two projects will use a PSA system and a Water Wash system respectively. Each of the projects will also use a different source of Biogas (a landfill and an agricultural digester). Specific items evaluated will include:

    - Contaminant removal efficiency/methane losses;

- Performance to meet and/or exceed the Company's gas quality specifications;
- Actual operating and maintenance costs of the equipment; and
- Equipment reliability.

2. Validation of expected Production levels and output. These projects will provide a means of evaluating the consistency in Biogas production levels and ability of upgrading equipment to operate effectively over any variations that occur as a result of changing input conditions.

The lessons learned through the purchase and quality monitoring of Biomethane from the project partners will be used to improve the processes in the development of other Biogas upgrading projects. Terasen Gas is in a unique position, along with the support of customers who choose to participate, to provide leadership to advance these types of projects with the hope that Biogas developments will in the longer term be able to deliver sustainable environmental benefits at a reasonable cost.

9.4.2 OTHER LEARNINGS

These first two projects will help Terasen Gas to understand the reliability of Biomethane supply. This will help to improve forecasting of the supply and allow Terasen Gas to improve the future match between Biomethane supply and demand.

Further, as Terasen Gas operations staff gains experience with the Biomethane supply, they will be able to provide feedback for consideration in future projects. It is expected that this will be particularly helpful when estimating future operational costs and when designing future Biogas projects.

9.5 Conclusion

The projects outlined in this Section represent important steps in developing a stable Biomethane supply for the Green Gas offering. The projects provide tangible benefits, with modest risk to customers. Terasen Gas believes that the success of these initiatives will open new possibilities to work with other partners.

10 COSTS, ALLOCATION AND ACCOUNTING TREATMENT, AND RATE SETTING

10.1 Introduction

The costs associated with the Green Gas program will be recovered through customer rates. Terasen Gas has developed a principled approach to allocating and recovering costs from customers. Certain costs incurred on behalf of Green Gas customers will be allocated to those customers and recovered through the Green Gas offering. Other costs, which will be incurred on behalf of all customers to make the Green Gas offering available to all, will be recovered from all customers.

This Section explains:

- The general cost recovery principles applied;
- The costs that will be incurred;
- The associated accounting treatment; and
- The Company's proposal with respect to which customers should bear which costs associated with the Green Gas program and how rates will be determined.

10.2 General Cost Recovery Principles for the Green Gas Program

The Biomethane sold to customers is expected, at least for the foreseeable future, to be more expensive than conventional natural gas. As such, Biomethane will be positioned as a premium product that eligible customers may choose to purchase, based on supply availability. Those customers who elect to purchase Biomethane will pay higher costs associated with its acquisition.

The Company is proposing that customers opting into the Green Gas offering and committing to purchase Biomethane should pay the full costs to supply pipeline quality Biomethane gas. For projects where Terasen Gas will acquire raw Biogas and process the Biogas into pipeline quality Biomethane gas, the acquisition costs of the raw Biogas, and the costs of owning and operating the upgrading equipment will be fully recovered from only Green Gas customers via the Biomethane rate. Similarly, for those projects where Terasen Gas will acquire pipeline ready Biomethane, the costs of purchasing that Biomethane will be fully recovered from only Green Gas customers via the Biomethane rate. Incremental CWLP charges related to processing customer enrolments in the Green Gas offerings and ongoing O&M such as customer drops, moves and changes will be fully recovered from only Green Gas customers via the Biomethane rate.

However, some costs are being incurred in order to give all customers the choice of participating in the Green Gas program, and all customers obtain environmental benefits from the Company offering Biomethane as an option. Consistent with the implementation of other programs, such as the Customer Choice program, Terasen Gas believes that costs incurred to provide this choice and deliver environmental benefits should be allocated to all customers of the utility. The costs to be allocated to all utility customers include the costs associated with the capital assets downstream of the receipt point of Biomethane on the Terasen Gas system and the costs to provide consumers with the option to purchase Biomethane.

Appendix J-1 summarizes all the O&M and capital costs included in the determination of the rate impacts, and the allocation of costs between all customers and those customers who choose to participate in the Green Gas program.

10.3 Determination of Costs related to System Changes

Terasen Gas commissioned KnowledgeTech Consulting Inc.[90] to assist in assessing the required business system changes (the "Project") and estimates for the costs required to implement the new Green Gas program. The review included business process impacts and costs in various areas in order to implement the billing, tracking, reporting and management of a Green Gas program such as:

A) Set up of New Biomethane Product or Supply Point in System

B) Green Gas Customer Enrolment

C) Green Gas Customer Drops

D) Green Gas Account Finalization

E) Green Gas Customer Inquiries

F) Green Gas Program Management

G) Biomethane Nominations and Supply Balancing

H) Biogas Producer Settlement

I) Green Gas Customer Billing

J) Biomethane Off System Sales

K) Green Gas Rate Setting

[90] See Appendix K for Statement of Work and Company Credentials - Established and incorporated in British Columbia in 1993, KnowledgeTech ("KTC") is a leading Western Canadian based management and information technology consulting services firm headquartered in Vancouver. KTC's client focus is Energy/Utilities, Healthcare, and Financial Services.

The scope of the Project included overall program management and solution architecture as well as the development, testing and deployment required to support updates, configuration and implementation of billing systems, processes and ongoing customer care operations to support a Green Gas program by CWLP. The outcome of the review showed that there were minimal internal cost impacts and some minor billing system changes required in order to support a Green Gas offering under the proposed Green Gas business model. These identified costs have been included in the Application and are included in the costs that are summarized in Appendix G, Tables G1-G6 .

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. The new customer information system ("CIS") is expected to be implemented January 1, 2012. Assuming the Green Gas program is available to customers for October 1, 2010, there would be approximately 15 months supported by the current system before moving to the new CIS. As such, the Company was mindful of minimizing system changes for application support and development requirements that are proposed to be recovered by all customers for new processes and reports required to support Green Gas enrolment. The transition of customer care from an outsourced to in-house model will mean different on-going support costs pre and post 2012. These costs have been shown separately.

Terasen Gas believes that it has developed a cost-effective and workable solution along with supporting processes and systems to implement a Green Gas program effectively in British Columbia. This is achieved through a combination of simpler business processes, expanding the capabilities of existing systems, as well as some cost effective automation. Overall, these changes enable a broader range of program features while minimizing risks and costs by staging the rollout in a manner that permits customer billing system changes to be minimal over the next 15 months.

10.4 Costs to be Allocated to all Customers

As discussed above, the general principle employed in allocating costs is that costs incurred in order to give all customers the choice of participating in the Green Gas program, and to extend environmental benefits to all customers will be allocated to all customers. Costs which will be allocated to all Terasen Gas distribution customers will include:

- Costs related to ensuring that the Biomethane is able to reach the distribution system safely, including the 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 new Biomethane tariff; and
  - Provide additional reporting.
- On-going operating costs which are summarized in Appendix J-1:
  - Additional customer inquiry calls requesting general information about the Green Gas program;
  - Quarterly updates to the Terasen Gas Standard Rate portion of the Biomethane tariff (blended) rate;
  - Customer education costs, including costs associated with marketing the program to customers with details about the Terasen Gas Green Gas program; and
  - A Full-Time-Equivalent ("FTE") for a new position of Biogas Program Manager created for the implementation, communications, tracking, accounting, reporting and management of the Green Gas program.

No additional capital costs have been estimated for changes to the new CIS system as the following requirements for Biomethane are expected to be supported by CIS at initial implementation:

- Ability to show two commodity line items on a customer's where consumption is allocated to two or more tariffs should the Company want to display the tariff offering in this manner (e.g., 10% of the consumption to a Biomethane tariff; 90% to a standard tariff;
- Ability to have an effective date on a premise's participation in a heat zone; and
- Ability to automatically update the premise heat zone for premises within proximity of a Biomethane supply point, as determined by Systems Planning).

10.5 Accounting and Rate Setting Treatment of Costs Related to All Customers

Capital expenditures related to gas analyzing equipment, meters, transmission or distribution pipeline extensions constructed to receive the injection of Biomethane will be held in Work-In-Process until the assets are available for use, at which time they will be included in rate base.

Terasen Gas is proposing the creation of a non-rate base deferral account to capture the costs applicable to all customers incurred prior to January 1, 2012 (the remainder of the 2010-2011 revenue requirements period). Terasen Gas 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 costs to be captured in the deferral account include:

1. The cost of service value related to the assets being included in Rate Base – i.e. Earned Return, Depreciation Provision, and Income Tax. This would be accomplished by crediting Other Revenue and debiting the deferral account.
2. O&M expenditures (net of tax), consisting of the costs of upgrading the CWLP system to allow the launch of the Green Gas program and the ongoing costs of updating that tariff information, the costs of CWLP answering informational calls regarding the Green Gas program and other planned Customer Education costs and the cost of one FTE to administer the Green Gas program.

Delivery system-related Capital and O&M costs to be incurred after January 1, 2012 will be forecast as part of future revenue requirements and will not require deferral treatment.

The schedules attached in Appendix J-1 provide the forecast costs and delivery rate impacts of the proposed accounting and cost recovery treatment for the costs related to all customers.

As set out in Appendix J-1, Schedule 11, the rate impact on Terasen Gas non-bypass customers from 2012 – 2019 varies from $0.004 to $0.006 per GJ; the levelized rate impact is $0.004 per GJ. The present value of the incremental revenue requirements for this period is $4,084,100. For a residential customer using 95 GJ per year the annual incremental cost is 38 cents. The levelized rate is derived based on the discounted value of the cost of service in each of the years.

In Appendix J-1, Schedule 12 the discounted cash flow is calculated which shows a positive value of $105,000. The terminal value used in this calculation is derived by calculating the present value of the tax shield of the residual undepreciated capital cost at the end of 2019 plus the present value of the free cash flow in 2019 which is assumed to continue indefinitely. The discount rate used in the calculation is Terasen Gas' after tax weighted average cost of capital.

The Company believes the use of a deferral account is appropriate for the remaining duration of the revenue requirements period, but that the future costs should be included in the utility's rate base and cost of service effective January 1, 2012 as the safe operation of the distribution system provides benefits to all Terasen Gas customers.

Terasen Gas is seeking approval in this Application to collect the costs of service associated with the additions to the delivery system in the form of capital costs, as well as the delivery system related O&M costs in a deferral account, and to recover these costs from all Terasen Gas customers via delivery rates, effective January 1, 2012.

10.6 Costs to be Allocated to Green Gas Customers

As discussed above, the general principle employed in allocating costs is that costs incurred on behalf of Green Gas customers will be allocated to those customers and recovered through the Green Gas offering. Costs to be allocated to green gas customers consist of:

1. The cost of purchasing raw Biogas.
2. The cost of purchasing upgraded Biomethane.
3. The costs of upgrading raw Biogas to Biomethane, which consist of:
    a. Operating O&M for the upgrading equipment; and
    b. Capital-related costs of service for the upgrading equipment.
4. The ongoing administrative O&M costs of the Green Gas program directly incurred by Green Gas customers, which are summarized in Appendix J-1:
    a. CWLP charges for enrolling customers in the program;
    b. CWLP charges for removing customers from the program;
    c. CWLP charges for finalizations, moves and billing adjustments; and
    d. CWLP charges for bill adjustments related to the heat content of Biomethane, described in the following paragraph.

Additional O&M costs incurred to bring Biomethane into the pipeline system have also been included. Prior to being put into the Terasen Gas pipeline system, the Biomethane supply will be brought up to pipeline quality specifications. As discussed in Section 11.3.2, Terasen Gas will monitor gas quality and heat content on a continuous basis. Even if the Biomethane is within specifications, there may be an instance that the heat content value is less than the average used to bill customers in that area. Should the heat content value be less than the average for that zone, the Company proposes to monitor the heat content value on a regular basis and issue a credit to customers that may be affected by a lower heat content value in their zone.

10.7 Accounting and Rate Setting Treatment of Costs Related to Green Gas Customers

The Biomethane costs will be recovered from those customers choosing to enrol in a Green Gas rate offering through a Biomethane Energy Recovery Charge ("BERC"). As the Biomethane rate will be based on forecast costs, and actual costs invariably differ from forecast costs, a deferral account will be required to capture the variances between the BERC and the costs incurred. Terasen Gas seeks Commission approval of a deferral account to capture the costs incurred by Terasen Gas to procure and process consumable Biomethane gas and the revenues collected through the Biomethane energy recovery component of rates, and thereby accumulate any differences. Terasen Gas shall refer to this deferral account as the Biomethane Variance Account ("BVA").

What follows is a discussion of accounting treatment Terasen Gas is proposing for each type of cost proposed to be allocated to Green Gas customers. The costs include capital costs, operating cost and commodity acquisition costs. Also discussed is the proposed reporting method and cost recovery mechanism, as well as the phasing of the proposals.

10.7.1 BIOMETHANE PRODUCTION / PROCESSING CAPITAL COSTS

The Biogas processing assets located upstream of the Biogas receipt point will be accounted for as Natural Gas Gathering Plant (British Columbia Utilities Commission Account Codes 410 – 419), consistent with the Uniform System of Accounts for gas utilities, and will form part of the utility's rate base. The upgrader equipment will be accounted for as Purification Equipment (Account 418). The expected life of the upgrader equipment is 15 years with a major overhaul that is approximately 20% of the original cost, required in the eighth year. For purposes of the application Terasen Gas is proposing to depreciate 80% of the original cost at 6.67% and 20% of the original cost and the overhaul cost at 13.33% (7.5 year life) consistent with IFRS.

As part of the determination of the BERC component of the Green Gas rate offering, an annualized cost of service amount (earned return, depreciation and income taxes) is calculated on the Capital costs of those assets installed to facilitate the receipt and processing of Biogas into a marketable and consumable Biomethane product.

These costs are related to the individual Biomethane projects and the forecast costs and Biomethane volumes presented within this Application relate to the two projects being proposed. As well, Commission approval of the cost recovery mechanism applicable to Biogas processing related assets is being sought within this Application

10.7.2 BIOMETHANE ANNUAL OPERATING COSTS

Other costs to operate the Green Gas program include administration expenditures to process customer enrolments and provide management reporting, and call centre related expenditures for the handling of customer inquiries. These costs will be charged to the BVA on a net-of-tax basis.

10.7.3 BIOMETHANE ACQUISITION COSTS

The costs related to the procurement of the gas, either in the form of a consumable-ready Biomethane gas product or as raw Biogas which requires further processing in order to create a consumable gas product, will be variable in nature and will vary with the volume of the Biomethane or the Biogas supply purchased. These costs will be captured directly in the BVA on a net of tax basis.

As discussed in Section 10.7.3 of this Application, in the unlikely event that customers' consumption of Biomethane under the Green Gas offering exceeds the available supply in a given period, one of the mechanisms Terasen Gas is proposing to mitigate against the risk of under supply of Biomethane is to have approval to purchase carbon offsets in order to maintain the GHG emission reduction associated with Biomethane supply. These costs would be collected in the BVA, in the event that this proves necessary.

Terasen Gas has taken a number of steps to reduce the likelihood of carbon offsets actually needing to be purchased, but in the event they are, the Company proposes that the costs of purchasing these credits be appropriately recovered from Green Gas customers via the Biomethane rate. The Company requests Commission approval for Terasen Gas to purchase carbon offsets, if necessary, at a per gigajoule unit price not exceeding the difference between the Biomethane Energy Recovery Charge and the Commodity Cost Recovery Charge in effect at that time.

As discussed in Section 8, the effects of the Biomethane received at the Terasen Gas distribution system Biomethane receipt points will be minimal to the Terasen Gas gas supply portfolio. Terasen Gas Midstream, as it currently does, will continue to manage the balancing of all gas received. Actual Biomethane volumes received at the Biomethane receipt points will in effect be incremental gas to the system and Terasen Gas Midstream will manage these very small incremental supply volumes via displacement and, as appropriate, Terasen Gas Midstream will shed seasonal supply or increase off-system sales.

Further, until the Biogas program expands substantially and the Biomethane volumes become a material component of the gas supply portfolio, no incremental resources are expected to be required by Terasen Gas to perform the Midstream functions. Thus, there will be no impact to the existing Terasen Gas Core Market Administration Expenses ("CMAE") budget.

Customers choosing the core market Green Gas rate offering (at this time Rate Schedule 1B, with future development discussed above in Section 6 of this Application) will continue to pay the Midstream rate, which includes the CMAE related to the Terasen Gas Midstream function, as all Terasen Gas Sales customers do currently. Rate Schedule 1B customers will also continue to pay the Commodity rate, which includes the CMAE related to the Terasen Gas Commodity provider function, for the percentage of the energy received as the Standard Rate Offering natural gas (e.g. 90% of their billed consumption). The percentage of the energy Green Gas customers receive as Biomethane gas (e.g. 10% of their billed consumption) will not have any CMAE component embedded in the recovery rate, however, it will include the administration costs related to the Green Gas program.

10.7.4 BIOMETHANE VARIANCE ACCOUNT REPORTING AND RATE SETTING

Currently, all gas supply costs related to the Commodity and Midstream functions are captured in the Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation

Account ("MCRA") deferral accounts and recovered through the Commodity Cost Recovery Charge ("CCRC") and the Midstream Cost Recovery Charge ("MCRC"), respectively.

The current gas cost recovery mechanism utilizes quarterly reviews of the commodity and midstream costs and recoveries to determine if the current recovery charges are appropriately recovering costs. The CCRC is subject to quarterly review and resetting, as appropriate. The MCRC is subject to quarterly review and, under normal circumstances, is reset on an annual basis with a January 1 effective date.

Terasen Gas proposes that the BVA reporting and rate setting mechanism should align with the existing gas cost review and rate setting processes.

The Biomethane costs and recoveries will be reviewed on a quarterly basis, as part of the Company's quarterly gas cost report to the Commission. However, Terasen Gas recommends that the BERC be adjusted on an annual basis. There are three main reasons for this:

- First, the annual adjustment process for Biogas rates is appropriate as the cost inputs are not expected to be subject to wide variations. While due to the newness of this program, any daily processing volume variations are not able to be predicted with any certainty, it is expected that such variations will smooth out over an annualized time period.
- Second, an annual resetting of the Biomethane rate, using a January 1 effective date, would synchronize with the annual midstream rate and delivery margin adjustment processes, thereby helping to streamline communications with customers regarding rate adjustments.
- Third, an annual Biomethane rate setting process would allow for consistent timing to annually run the various Cost of Service models. In order to appropriately reset the BERC, the annualized Cost of Service of the Biomethane processing assets needs to be recalculated each year.

10.7.5 BIOMETHANE SUPPLY VOLUME TRACKING

Terasen Gas will track and report both volumes (supplied and sold) and dollars (costs and recoveries) related to the Green Gas rate offering and captured in the BVA.

Biomethane is a fundamentally different product from conventionally-sourced natural gas. In order to ensure appropriate matching of Biomethane supply volumes with consumption volumes, Biomethane costs and recoveries will need to be separately tracked and maintained from the other natural gas commodity for rate setting purposes. Over supply is not a significant issue as any excess Biomethane volumes can be sold in future periods.

The Company will track and report volumetric differences between the Biomethane supply available for sale and the Biomethane sold under the Green Gas sales rate offerings, or to other customers through on-system or off-system sales. The actual Biomethane molecules are received into the Terasen Gas distribution system at the Biomethane receipt points and are physically consumed by customers downstream of those receipt points. The energy being sold under the Green Gas program really relates to the selling of the green attributes of the Biomethane energy, and the volumes of Biomethane received at the Biomethane receipt points effectively displace other natural gas supply that would be required at those points in the system. Terasen Gas Midstream will still manage the overall balancing of all the gas in the system and will shed seasonal supply or increase off-system sales, as appropriate.

The volumetric differences between the Biomethane supply available for sale and the Biomethane sold will be tracked in the BVA and will be used to ensure these volumetric variances are accounted for when reviewing and resetting the BERC. The BVA will also capture all the cost and recovery variances related to both price and volume variances, including the volumetric variance related to yet unsold Biogas supply.

It is expected the volumetric imbalances will be managed in order to maintain a modest cushion of excess Biomethane supply but that under normal circumstances it would not be allowed to become excessive.

Until such time that the total Biomethane supply reaches a point that it could become a component of baseload supply, there will be no need to incorporate the Biomethane costs as part of the valuation of the system gas either as gas in storage or linepack inventory.

Ideally there will be a cushion of Biomethane supply built up in the BVA and this will ensure there is less chance of incurring a shortfall where Biomethane consumption exceeds Biomethane supply, which would necessitate the purchase of additional GHG credits.

The benefit of having a positive volumetric balance in the BVA is that any production challenges or interruptions can easily be handled and there will be Biomethane available to meet the ongoing Biomethane demand for those customers opting to purchase the Biomethane blended commodity.

There are expected to be two main types of supply build up that can occur in the BVA:

- The first relates to a temporary increase in supply (supply excesses) and can occur where during early stages of a production project the consistency of production is low and some days there will be more supply than others (the customer enrolment will be set to match a conservative production number so overall supply should exceed demand). This is a temporary or timing related supply build up. The excess can be carried or, if the Green Gas program manager determines the cushion is becoming too large, a one-time sale of some of the excess Biomethane can be accommodated via an off-system sale through Rate Schedule 30 with the amendments proposed in this Application, or an on-system sale through Rate Schedule 11B;
- The second type of supply build up relates to a permanent change in the supply where existing production / processing facilities have achieved a greater level of operating

efficiency and there has been a permanent increase in the Biomethane production volumes, or new Biomethane projects have been approved and have come on line. In cases where there has been a permanent type of increase in supply, the Green Gas program manager can take the necessary steps to open additional Biomethane offerings (or accept enrolments from the wait list) and thereby adjust the ongoing demand to match the new supply.

10.7.6 TERASEN GAS BIOMETHANE ENERGY RECOVERY CHARGE

In this Application, Terasen Gas requests approval for the proposed deferral account treatment and the proposed cost recovery methods for the estimated initial capital costs and the annual operating costs of providing the Green Gas rate offering effective October 1, 2010.

The schedules attached in Appendix J-3, filed confidentially, provide the forecast costs and rate impacts of the proposed accounting and cost recovery treatment for the two projects as proposed in Section 9 of this Application

As shown in the Schedule 11 in Appendix J-3 ((confidential) Terasen Gas has calculated the Biomethane Energy Recovery Charge at $9.904/GJ and seeks approval that the Biomethane Energy Recovery Charge be set at this amount effective October 1, 2010.

10.7.7 OVERVIEW OF THE FIRST PHASE OF THE GREEN GAS (RATE SCHEDULE 1B) BLENDED COMMODITY SERVICE OFFERING

By electing to participate in the first phase of the Green Gas offering, residential customers will pay a gas commodity price based on a 10% Biomethane and 90% natural gas blend. The Green Gas offering will provide customers with the opportunity to elect to purchase a Biomethane blend, initially under the Rate Schedule 1B tariff, and thereby reduce their carbon footprint.

The 90% natural gas component of the blend will be the same as the Terasen Gas standard commodity offering, and will remain as part of the Terasen Gas commodity supply portfolio. The cost recovery rate for this gas will be the same CCRC that all Terasen Gas standard commodity sales customers pay, and will be subject to the quarterly review and resetting mechanism.

The 10% Biomethane component of the blend will be established based on the forecast Biomethane costs and the forecast volume of Biomethane available for sale. A mechanism consistent with the existing gas cost recovery methodologies is being proposed wherein the Biomethane costs will be treated as variable in nature for rate setting purposes, consistent with the methodology currently in place for establishing the CCRC. However, as the Biomethane supply and processing costs will be based on long term contracts, and will not be subject to the same commodity market fluctuations as natural gas, the BERC is proposed to be reviewed quarterly, consistent with other gas cost recovery rates; however, under normal circumstances it will be reset annually using a January 1 effective date. As the Application proposes Biomethane volumes to be made available to customers effective October 1, 2010, the Biomethane recovery rate being requested effective October 1, 2010 has been determined based on the 15-month prospective period. Forecast costs to December 31, 2011 and the forecast Biomethane volume available for sale to December 31, 2011 will be the underlying basis for the BERC effective October 1, 2010. Although the Biomethane costs and recoveries will be reviewed and reported on a quarterly basis, as part of the Terasen Gas quarterly gas cost reporting process, the BERC is not expected to require resetting until January 1, 2012.

Effective October 1, 2010, residential customers will have the choice to elect to receive commodity at a Marketer rate under the Customer Choice program (RS 1U), at the Biomethane Blended Rate (RS 1B) under the Biomethane offering, or at the Terasen Gas Commodity Cost Recovery Rate (RS 1) under the standard rate offering.

Customers who choose to remain on the Terasen Gas standard rate offering will continue to pay the Terasen Gas commodity and midstream rates which will not include any costs related to the Biomethane production / processing costs.

10.8 Conclusion

Section 10 above has detailed the methodology Terasen Gas proposes to recover the costs of Biomethane and the Green Gas program from the appropriate customers in a timely manner. The Company is of the view that the principles proposed in the beginning of this Section result in a fair and reasonable allocation of costs. The detailed methodologies proposed in Sections 10.4 and 10.5 appropriately reflect these principles.

11 RISKS AND RISK MITIGATION

11.1 Introduction

Terasen Gas discussed the risks and mitigation steps specific to the Abbotsford and Salmon Arm Projects in Section 9 of the Application. In this Section Terasen Gas discusses three risks associated with the Green Gas program generally, and how it intends to manage those risks. The risks addressed are:

- The risks associated with the potential for over or under-supply of Biomethane (i.e. the overarching "program risks");
- The risks associated with specific supply projects, including project cost risk, system safety and reliability risk, and project specific supply risk; and
- Heating value difference.

Terasen Gas is confident that it has identified the key risks associated with the Green Gas program, and has put in place appropriate mechanisms to manage those risks.

11.2 Program Risks

Terasen Gas has detailed in prior Sections the demand forecasts based on survey results and the preliminary estimates of the availability of economical supply. Terasen Gas' approach is to grow supply in tandem with demand. The Company has, in the interests of diligence, taken additional steps to mitigate risks of either over or under-supply of Biomethane.

11.2.1 UNDER-SUPPLY RISK

Under-supply could be caused by producer failure or supply disruption, or a sudden and unexpected increase in the number of customers. The Company will proactively mitigate this risk by setting sales targets and customer enrollment caps at the minimum volume of gas that producers have contracted to supply. As suppliers have a financial incentive to produce more Biomethane rather than less, Terasen Gas expects this alone will ensure under-supply does not occur.

In the event that, for any reason, there is more consumption of Biomethane than there is supply, the Company has reserved the right to purchase carbon offset credits in order to retain the integrity of the GHG reduction. If the under-supply is resulting in a structural deficit, Terasen Gas has also reserved the right to remove customers from the program if it deems necessary in accordance with the new proposed Section 28 of the Terasen Gas General Terms and Conditions. See Appendix F-1.

11.2.2 OVER-SUPPLY RISK

Over-supply could be caused by higher than expected production or under-subscription by customers. The Company has the option of dealing with over-supply in three ways.

First, since the product is a notional delivery of Biomethane rather than the actual physical supply of the product, Terasen Gas has the option of notionally banking the Biomethane and selling it to customers at a later point in time. The customers for the "banked" Biomethane could come from a resurgence in the customer base for the Green Gas offering from additional marketing efforts or from an expansion of the program into other rate classes.

Second, the Company could sell the gas to third parties through an off-system transaction. The emergence of mandatory renewable power portfolios has caused electric utilities across North America to seek out Biomethane supply for their natural gas fired power production and major natural gas marketers have expressed an interest in purchasing the product in order to serve these utilities. Such a sale would be done through the existing structure of Terasen Gas Rate Schedule 30, which sets out the terms for Gas Electronic Data Interchange ("GasEDI"). The existing GasEDIs, currently already approved by the Commission, can be used for gas sold on the spot market that is notionally Biomethane.

Spot market Biomethane sales will need to follow British Columbia government rules that define how gas retains its carbon neutral status once it enters the Terasen Gas system and becomes notional Biomethane gas. Biomethane gas sales will likely need certification that the notional Biomethane gas has this status conforming to the jurisdictional rules of the receiving counterparty. As the Biomethane is produced at the respective plants, it will also need to be transported to an interconnect point between the Terasen Gas system and a transmission system. As discussed in Section 6.7.3, the Company proposes to recover a wheeling charge from parties purchasing Biomethane in the off-system marketplace, and more specifically proposes to base this charge on the interruptible transmission toll specified under Rate Schedule 27. This interruptible transmission toll would be in addition to the commodity sale price that is negotiated between the parties. Third parties purchasing Biomethane for use on the Terasen Gas system would not be subject to this wheeling cost as the Biomethane would be consumed on-system and would not require delivery to one of Terasen Gas' receipt hubs as defined in the ESM.

Third, Terasen Gas can sell the gas to on-system customers through Rate Schedule 11B, for which Terasen Gas is seeking approval in this Application. Rate Schedule 11B allows gas sales to on-system transport customers who are currently paying for their gas deliveries through a transportation tariff with Terasen Gas. In the interests of mitigating the risk of over-supply and ensuring that Biomethane reaches as many residents of British Columbia as possible as quickly as possible, the Company has agreed to sell the first 10,000 GJs of Biomethane produced in the Green Gas program to CHDL, which is a current natural gas transport customer under Rate Schedule 22 in the Lower Mainland. CHDL owns and operates a district energy system located in Vancouver serving downtown businesses and residents and relies on natural gas to generate thermal energy using natural gas boilers on its premises. CHDL has stepped forward to commit to purchase Biomethane in order to reduce its greenhouse gas footprint for its operations. CHDL's Letter of Intent to purchase this Biomethane can be found in Appendix L-1. Since the first supply of Biomethane is expected to flow to the Terasen Gas system three months before a Green Gas program can be launched to residential customers, this agreement will help reduce the amount of surplus gas received by the Company and mitigate costs and risks of over-supply. It will also create a partnership with CHDL that Terasen Gas will use to increase customer awareness of the availability and benefits of Biomethane, helping to augment the customer education program proposed in this Application.

11.3 Supply Project Risks

New supply projects present cost and operational risks that must be managed. Terasen Gas intends to manage cost risks primarily through contractual arrangements. From an operational perspective, Terasen Gas believes that the injection of Biomethane into the distribution system poses little risk to the system.

11.3.1 COST RISK

Biogas projects may only require relatively modest capital investments by Terasen Gas. However, cost risks associated with a supply project can be handled in several ways.

First, where possible Terasen Gas will validate project cost estimates by including field data. An example of this diligence includes dispatching Terasen Gas staff to project sites to record local conditions and improve the quality of cost estimates for terrain-sensitive items such as main extensions. Future projects will also benefit from re-using engineering costs for items such as interconnection stations with similar flows.

Secondly, when purchasing upgrading equipment Terasen Gas will seek fixed price contracts with performance guarantees where it is cost-effective to do so.

Thirdly, a contingency may be added to project costs.

The Company believes that these three practices will ensure that supply project cost risks are minimized.

11.3.2 OPERATIONAL AND SYSTEM RISK

As the operator of the distribution system, it is incumbent upon Terasen Gas to ensure the safe use of our system. As the market for Biomethane develops, the Company will remain involved in ensuring that associated facilities are operated and interconnected to Terasen Gas facilities in a safe and reliable manner. The process undertaken with respect to the two projects identified in this Application is illustrative of the approach that Terasen Gas will be taking.

In order to assess the capability of the local system to receive Biomethane from the two projects discussed in this Application, basic system capacity analysis was performed by the System Planning group in Terasen Gas. Planning was based on summer load factors to ensure a conservative approach was taken. From a system capacity perspective there are no issues related to the Projects since the Biomethane volumes are very small compared to the capacity of the local system. Terasen Gas has deliberately adopted a policy of continuing to purchase and plan for gas assuming that the Biomethane supply is not available. This policy will ensure that there is always an adequate supply for customers from existing supply sources.

Unlike natural gas, Biomethane does not contain ethane or propane. Current Terasen Gas operational procedures rely on the presence of ethane or propane in natural gas to help with detection of leaks. Instruments are calibrated to detect ethane or propane in order to avoid possible confusion with other naturally occurring sources of methane ("swamp gas") such as marshes. Therefore, current practice may not detect a Biomethane leak. There are several ways to deal with this risk:

A) A review of routine leak survey records in the immediately impacted area may be done to confirm that there are no leaks or readings for swamp gas which is often mistaken by the public as natural gas.

B) The Biomethane will be odorized through a bypass prior to injection into the distribution system. Terasen Gas will build and operate the odorant injection equipment as part of the interconnection facilities.

C) In the event of a suspected leak, the Biomethane supply can either be shut off (in which case natural gas would flood the local piping) or propane can be injected in small amounts at the source (Biomethane connection point) allowing standard leak detection practice.

Terasen Gas will incorporate these practices into operational procedures to ensure that Biomethane leaks will not pose any additional risk to customers or employees. The procedures will improve over time as Terasen Gas gains more experience with the Biomethane supply.

Terasen Gas will own, operate and maintain the odorant equipment, meter, regulator and valves at the injection point. This will provide assurance that gas flow can be monitored and stopped immediately if required.

For projects where Terasen Gas owns upgrading equipment, Terasen Gas will be well-supported to deal with any operational risk specific to that equipment. Firstly, existing staff are competent to deal with gas safety issues and the operation and maintenance of gas equipment including the basic components that make up an upgrading plant. Terasen Gas will have access to key equipment manufacturers for maintenance and operational advice. Ongoing maintenance will be performed according to manufacturers' recommended schedules. Ongoing monitoring and operational data analysis will also be done in order to ensure optimum upgrading equipment performance. Terasen Gas will refine procedures and processes to ensure Biogas-related equipment is managed to the same level as all other existing assets.

The status of Biogas facilities will be monitored by our Gas Control staff. This will provide Terasen Gas with the ability to respond to calls according to standard operating procedures. Terasen Gas will also include procedures in its Emergency Response Plan.

With respect to gas quality, the Biomethane will meet the pipeline quality specification based on the published requirements in the Westcoast Energy Inc. tariff. This is the current standard under which Terasen Gas receives gas into its transmission and distribution system. In addition, Terasen Gas will monitor the gas quality for any unexpected contamination and may impose additional requirements on Biomethane in the future.

As an additional measure to gain confidence in gas quality, Terasen Gas will monitor the gas quality from projects in real-time during the months following start-up. It is anticipated that this will be done both at the outlet of the upgrading plant and at points along the distribution system within the area. The monitoring is intended to confirm the assumptions used as well as providing data to allow for quality control and operational adjustments. The costs associated with this equipment will be treated as part of the project costs.

Finally, with respect to system risk, in the unlikely event that the Biomethane was to negatively affect the quality of gas being consumed in customers' appliances, the overall impact would be manageable. Low volumes of Biomethane will be produced and injected into the distribution infrastructure. In the case of the CPI project, for example, system analysis of the surrounding distribution network indicates that the maximum number of customers that could be burning the Biomethane is approximately 240 and at the Salmon Arm project the number would be smaller. While it is not anticipated that the Biomethane will result in customers noticing any difference in the operation of their appliances or any adverse impacts, one of the key objectives of the early projects is to validate this assumption so that future larger scale projects can move forward with even higher confidence.

Terasen Gas will continue to exercise the same level of care and diligence in operating Biomethane supply that customers and employees have come to expect over the history of the Company. Each of the identified operational risks will be addressed with planned operational changes or appropriate measures. Terasen Gas is confident that Biomethane supply can be integrated into the existing operations in a safe manner.

11.3.3 EFFECT ON RESOURCE PORTFOLIO

The supply of Biomethane is expected to grow over time. As this supply grows its potential impact will be considered within the gas supply Annual Gas Contracting Plans. Over time any resource decisions and contracting practises will be reviewed and implemented as part of that annual review. These new supply resources will not have any impact to the Essential Services Model (ESM) and its underlying business rules.

Terasen Gas recognizes that managing Biomethane supply is new in this service territory and there may be some risk associated with availability of Biomethane supply. In terms of specific supply projects, Terasen Gas is seeking to mitigate supply risk in several ways.

First, when developing supply agreements Terasen Gas will seek to include minimum supply volumes and include commercially reasonable penalties for failure to supply.

Secondly, when developing cost of service models and evaluating project viability, Terasen Gas may apply risk mitigation factors to the forecast volumes. This may include a variable such as availability of equipment and a reduction in expected volumes to provide additional confidence in the forecast volumes.

Thirdly, Terasen Gas will seek to use the highest value commercially available technology and stable partners when developing supply projects. For example, for both of the projects included in this Application, the upgrading technology providers have experience with multiple projects at multiple locations around the world over a period of several years. In the case of the CPI project the technology used for upgrading was first developed in 1985.

Finally, Terasen Gas may seek to contractually include a right of first refusal to ensure partners will offer future gas to the Company. In the case of some Biogas sources, such as landfills and wastewater plants, there may be growth in supply as a result of increasing local populations at the Biogas source area.

11.4 Heating Value Difference

Terasen Gas currently receives gas from more than one natural gas pipeline company and distributes this gas to its customers across the province. Natural gas is produced by aggregating numerous supply sources with different physical properties. Therefore, gas composition and heating value (which is based on gas composition) vary across the province. Terasen Gas monitors gas composition at several key locations across the province and uses the gas composition to determine heating values which are then applied to calculate customer bills.

As mentioned earlier, Biomethane will meet the Terasen Gas Quality Specifications. However, Terasen Gas typically receives and supplies gas that exceeds the minimum required heating value of 36 MJ/m^3 specified[91]. In the event that Biomethane meets the minimum requirement, but does not match the natural gas heating value, there may be some variation in the flows to residences located in the immediate vicinity of a Biomethane injection point. This phenomenon may show itself in increased flows to customers to meet energy needs. For example, if the heating value of Biomethane is lower, a higher flow may be required to meet the same energy requirement in a home and the bill may not be accurate. In order to address this variation, and ensure local customers are billed appropriately, Terasen Gas will monitor gas composition and flows. The planned mitigation measures to address this issue will be a combination of modeling and sampling. This involves five steps:

- **Step 1** – *Monitor and measure at the injection point:* Terasen Gas will monitor gas quality (chemical composition), flow, pressure and temperature at the injection point in real-time with on-going sampling. From this data, a heating value will be calculated. If the Biomethane heating value matches the heating value of the natural gas being displaced there is no impact to customers. If the heating value does not match customers in the area immediately surrounding the Biomethane injection point, customers will receive gas with a different heating value than they are being billed for, resulting in small but not immaterial billing discrepancies. The Company recognizes the need to ensure that these customers are fairly compensated for any billing discrepancies that occur.
- **Step 2** – *Determine correct heat factor:* Assuming the gas has lower heat content (for example 36MJ/m^3 – an expected 5.2% difference from 38MJ/m^3) a new factor will be calculated to determine energy delivered to the affected customers.
- **Step 3** – *Determine affected customers:* This will be done using a combination of modelling and field data to confirm accuracy. Terasen Gas will use established system planning models to determine the affected customers geographically. The extent of affected customers will be confirmed with gas sampling in the field. This will be done quarterly, once for each season.
- **Step 4** – *Adjust bills:* It is expected that the geographic reach of Biomethane from the plants will change throughout the year. That is, in the summer when demand is lower, Biomethane will travel further in the system because individual consumers are using less. For the purposes of billing, Terasen Gas will assume a maximum propagation and change the billing factors for the impacted customers. In some cases, such as transition months, certain customers may be receiving natural gas at a higher heating value than Biomethane, but may be billed assuming a lower heating value gas. Those customers would experience a small financial benefit. The Company believes this is preferable to having any customers be financially penalized for consuming gas in the vicinity of a Biomethane injection point.

[91] Terasen Gas has adopted the specification in the Westcoast Energy General Terms and Conditions. Westcoast Energy is now Spectra Energy – the primary source of gas for Terasen Gas in the province.

- **Step 5** – *Reconciliation:* As a final step, Terasen Gas will reconcile delivered Biomethane with billed Biomethane so customers will pay for their consumption associated with the correct heating value. The cost to process any billing adjustments will be borne by the Green Gas customer base. In other words, non-Biomethane customers will not pay any costs associated with the reconciliation process. Based on early estimates, the costs to the program once the first two Biogas projects are online is in the range of $20,000 to $40,000 annually.

Terasen Gas believes that this process will ensure that customers who experience issues related to heat content as a result of being located near a Biomethane project will be kept financially whole.

11.5 Conclusion

Terasen Gas believes it has identified the risks associated with the Biomethane business model and will put appropriate measures in place to help mitigate these risks if they occur.

12 STAKEHOLDER CONSULTATION

12.1 Introduction

Over the 18 months leading up to the filing of this Application, the Company consulted a number of stakeholders regarding Terasen Gas' interest in pursuing the development of Biogas supply and a Green Gas offering. Terasen Gas believes that between its customer research and other consultation described below, it has obtained valuable information that has been reflected in many respects in the proposals.

The following sections provide an overview of the consultation process for each stakeholder group, the issues raised, description of issue resolution, and any outstanding issues that remain.

12.2 Customers

In Section 5 Terasen Gas discussed how it has surveyed customers to gather information that assisted in the design of the Green Gas offering. In addition, Terasen Gas consulted with representatives of the Commercial Energy Consumers Association of British Columbia and the British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Old Age Pensioners Organization *et al* ("BCOAPO").

12.3 Gas Marketers

Terasen Gas communicated its intent to file this Application in support of a Green Gas offering to the Customer Choice stakeholder group, consisting of the below-listed members.

- Access Gas Services Inc.
- Active Energy
- Active Renewable Marketing
- BCOAPO
- Columbia Fuels
- Direct Energy
- Econalysis Consulting Services
- IGI Resources Inc.
- Just Energy
- MX Energy
- Nexen Marketing

- Planet Energy
- Premstar
- SemGroup LP.
- Shell
- Smart Energy (BC) Ltd.
- Summitt Energy
- Superior Energy
- Superior Energy Management
- Thermal Environment Comfort Association

On March 5th, 2010 the Company sent the above-listed Gas Marketers and BCOAPO a document entitled “Biogas Program: Information for Gas Marketers and Request for Feedback”, a copy of which can be found in Appendix M-1. Terasen Gas received communication back from Just Energy (B.C.) Limited Partnership (“Just Energy”) and Access Gas Services (“Access Gas”), but did not hear from the remaining Marketers or BCOAPO.

Just Energy replied to the request for feedback in a letter which is included in Appendix M-2. Just Energy stated that they believe “it is important for all industry members to identify, investigate and develop solutions in keeping with the Government’s goals of introducing new clean and renewable forms of energy”. They went on to state that they do not object to the program as proposed, “provided that the program is introduced in a manner that does not obstruct or pose a detriment to Customer Choice and that no preferential treatment is allotted to Terasen Gas or its customers.”

Access Gas also replied to the request for feedback in a letter which is included in Appendix M-3. Access Gas expressed opposition to the proposed program.

Terasen Gas has considered the feedback from these marketers. The proposed Green Gas offering will co-exist with the Customer Choice program. It is supplementary to, and different from, the products and services offered by Gas Marketers. The proposed Green Gas offering is priced annually, based on the cost of service of providing the Biomethane. Marketers offer a three or five year fixed price contract for the purchase of conventional natural gas, even if offsets or other environmental attributes are attached to such a contract. Terasen Gas has restricted the offering at this stage for the reasons described in Section 6. Terasen Gas recognizes the possibility of making the supply of Biomethane available to marketers to integrate into their offerings once the product and market have matured sufficiently to make such an offering possible. Further, nothing proposed in this Application precludes Marketers from developing sources of raw Biogas supply. The Company has made every effort to ensure it has the capability to sell Biomethane to Gas Marketers as part of our risk mitigation planning.

12.4 Government

The Company has met with representatives of the Ministry of Energy, Mines and Petroleum Resources, the Ministry of Environment, the Ministry of Community and Rural Development, the Ministry of Small Business and Revenue, and the Ministry of Transportation and the Ministry of Agriculture. These briefings highlighted the main points of the proposed projects and the proposed program, and were met with generally supportive responses.

12.5 First Nations

The Company is of the view that the Abbotsford and Salmon Arm supply projects proposed in the Application do not have the potential to adversely impact the physical, biological, or social environment. Nevertheless, the Company provided notice of its intention to apply for approval of these two supply projects to the First Nations in the surrounding areas. The letters are found in Appendix M-4 of this Application. The letters describe the respective supply projects and invite the First Nations to provide any comments or concerns that they may have. At the time of filing, Terasen Gas has not received any responses to these letters.

As the proposed program grows to include additional supply projects, the Company is committed to evaluating each new project for the potential need to consult any affected First Nations. In the event that such consultations are appropriate, Terasen Gas will include details of these consultations in the filing of future supply agreements.

12.6 Public Forums

As a part of the Company's early exploration of a Biogas business model, the RFEOI process also formed a part of our consultations with external stakeholders. In the fall of 2008 Terasen Gas held four information sessions with interested parties in Victoria, Abbotsford, Prince George and Kelowna.

In total, approximately 150 pre-registrations were received and 126 individuals attended the workshops. The Abbotsford session had the largest stakeholder turnout at approximately 80 people. Each of the other locations had attendance in the range of 12 to 20 people. The backgrounds and organizational representation of those who attended was diverse and well suited to the development of a Biogas industry, including individuals representing potential project proponents, the agriculture community, the forestry sector, the food and milk processing industry, municipal councils, municipal waste and wastewater planning, financial services, technology providers, consultants, regulatory and related agencies and associations.

The nine projects that came forward with formal Expressions of Interest represented approximately 750,000 GJs of potential supply.

12.7 Letters of Support for This Application

Terasen Gas has received letters of support for this Application from the below organizations. Copies of these letters can be found in Appendix L-2.

A) BC Agricultural Research & Development Corporation

B) BC Bioenergy Network

C) BC Sustainable Energy Association

D) Bullfrog Power

E) Central Heat Distribution Limited (Appendix L-1)

F) City of Abbotsford

G) Columbia Shuswap Regional District

H) David Suzuki Foundation

I) Pacific Carbon Trust

12.8 Conclusion

The extensive stakeholder consultations conducted by Terasen Gas in the 18 months prior to filing this Application, combined with the customer research conducted, have yielded feedback reflected in aspects of this Application.

13 CONCLUSION

Biogas is a renewable energy source that can be upgraded to carbon neutral Biomethane. When Biomethane is injected into Terasen Gas' distribution system it offsets the use of natural gas and reduces GHG emissions. The Green Gas offering represents a significant first step in the development of Biogas as a new source of renewable energy to meet Terasen Gas' customers' needs and the "government's energy objectives".

Terasen Gas, as the major natural gas utility in British Columbia, is uniquely positioned to promote the development of Biogas upgrading in BC. The model Terasen Gas has developed to deliver this product to its customers will allow for prudent, economical, and flexible development of this renewable energy source.

Terasen Gas respectfully requests that the Commission grant the orders as sought in this Application.

14 APPROVALS SOUGHT

In this section, Terasen Gas identifies the approvals sought in this Application. A draft form of Order containing all of the approvals sought by Terasen Gas can be found in Appendix N-2.

TGI respectfully seeks the following orders from the Commission pursuant to the *Utilities Commission Act* (the "Act"):

Rate Related Orders

1. An order pursuant to sections 59-61 of the Act approving:

   (a) the new Rate Schedules 1B, 11B, and the amendments to Rate Schedule 30; (see Section 6.7.1 and Section 6.7.3);

   (b) the new Rate Schedules 2B and 3B effective upon filing of the rate schedules with the Commission, but in any event not before January 1, 2012 (see Section 6.7.2);

   (c) the proposed amendments to Terasen Gas' General Terms and Conditions, specifically, the addition of new definitions relating to the Biomethane Service, and the introduction of a Section 28 – Biomethane Service (see Section 6.7.4).

Cost Recovery Related Orders (All Customers)

2. An order pursuant to sections 59-61 of the Act approving:

   (a) the allocation of costs to all customers and the accounting treatment of those costs as described in Section 10 of the Application.

   (b) a non-rate base deferral account attracting AFUDC to capture the O&M costs applicable to all customers incurred prior to January 1, 2012, and to recover these costs from all non-bypass customers by amortizing them through delivery rates commencing January 1, 2012 over a three year period (see Section 10.5).

   (c) a non-rate base deferral account to capture the cost of service associated with the capital additions to the delivery system incurred prior to January 1, 2012, and to recover these costs from all non-bypass customers by amortizing them through delivery rates commencing January 1, 2012 over a three year period (see Section 10.5).

Cost Recovery Related Orders (Green Gas Customers Only)

3. An order pursuant to sections 59-61 of the Act approving:

   (a) the allocation of costs to Green Gas customers and the accounting treatment of those costs as described in Section 10.6 of the Application.

(b) the cost recovery methodology applicable to Biogas processing related assets (see Section 10.6).

(c) a rate base deferral account to capture the costs incurred by Terasen Gas to procure and process consumable Biomethane gas and the revenues collected through the Biomethane energy recovery component of rates, and thereby accumulate any differences (the "Biomethane Variance Account") (see Section 10.7).

(d) the Biomethane Variance Account balance quarterly reporting process and the Biomethane Energy Recovery Charge rate setting mechanism on a basis consistent with the Company's existing gas cost reporting and rate setting mechanisms, as described in Section 10.7 of the Application.

(e) Terasen Gas purchasing carbon offsets and recovering the 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 (see Section 11.2.1).

(f) the Biomethane Energy Recovery Charge at $9.904/GJ effective October 1, 2010 (see Section 10.7.6).

Supply Project Related Orders

4. An order pursuant to section 71 of the Act accepting as filed:

(a) the Purchase of Biogas Agreement with the CSRD (see Section 9.2 and confidential Appendix I-1); and

(b) the Purchase of Biogas Agreement with Catalyst Power Incorporated (see Section 9.3 and confidential Appendix I-2).

5. An order pursuant to section 44.2 of the Act that the following capital expenditures are accepted by the Commission and are in the public interest:

(a) The expenditures relating to the facilities required for the Salmon Arm Project described at Table 9-1 of the Application; and

(b) The expenditures relating to the facilities required for the Catalyst Project described at Table 9-4 of the Application.

6. An order that future supply contracts for the purchase of Biogas or Biomethane filed with the Commission that meet the criteria described in Section 8.4, meet the filing requirements in sections 71(1)(a) and 71(1)(b) of the Act (see section 8.4.3).

Post-Implementation Review Orders

7. A direction that Terasen Gas, within 5 years of the date of this order:

   (a) file a Post-implementation Report that provides the information described in Section 8.4.4 of the Application; and

   (b) hold a Post-implementation Workshop, to be attended by Terasen Gas, and any interested stakeholders and intervenors, at which Terasen Gas will address the contents of the Post-implementation Report (see Section 8.4.4).

Appendix A

BIOGAS TO BIOMETHANE REPORT

(View Attachments Panel)

Appendix B

GOVERNMENT POLICY

Appendix B-1

ENERGY PLAN 2007
A VISION FOR CLEAN ENERGY LEADERSHIP

(View Attachments Panel)

Note: in an effort to reduce unnecessary paper consumption this appendix has been provided in electronic format ONLY hardcopy production will be provided only upon request.

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 903 *, Approved and Ordered* DEC - 8 2008

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that effective January 1, 2009,

1 the following provisions of the *Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008*, S.B.C. 2008, c. 20, are brought into force:

(a) section 1;

(b) section 2, insofar as it enacts sections 76.2, 76.21 and 76.5;

(c) section 6, insofar as it enacts section 114 (1) (a) to (f) and (2);

(d) section 11, insofar as it enacts section 120 (2) (a) to (d) and (f) to (h) and (3) (a) to (e), and

2 the attached Landfill Gas Management Regulation is made.

Minister of Environment

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section:- *Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008*, S.B.C. 2008, c. 20, s. 37

Other (specify):- *Environmental Management Act*, S.B.C. 2003, c. 53, s. 76.21

November 20, 2008 R/1243/2008/48

LANDFILL GAS MANAGEMENT REGULATION

Contents

Definitions

1 In this regulation:

"Act" means the *Environmental Management Act*;

"initial report" means a report, referred to in section 4 (3), for an initial landfill gas generation assessment;

"guidelines" means the most recent edition of landfill gas management guidelines approved by the director and published on a publicly accessible website maintained by or on behalf of the ministry;

"landfill gas" means a mixture of gases generated by the decomposition of municipal solid waste;

"landfill gas management" includes the following:

(a) managing migration of landfill gas;

(b) collection of landfill gas;

(c) storing of landfill gas;

(d) flaring of landfill gas;

"landfill gas management facilities" includes equipment, apparatus, fixtures and other structures used for landfill gas management;

"ministry" means the ministry administered by the minister;

"municipal solid waste" has the same meaning as in Part 3 of the Act;

"qualified professional", in relation to a duty or function under this regulation, means a professional who

(a) is an applied scientist or technologist specializing in a particular applied science or technology,

(b) is registered in British Columbia with a professional organization, is acting under that organization's code of ethics and is subject to disciplinary action by that organization, and

(c) through suitable education, experience, accreditation and knowledge respecting solid waste and landfill gas management, may reasonably be relied on to provide advice within their area of expertise, which area of expertise is applicable to the duty or function;

"regulated landfill site" means a landfill site that

(a) has 100 000 tonnes or more of municipal solid waste in place, or

(b) receives 10 000 or more tonnes of municipal solid waste for disposal into the landfill site in any calendar year after 2008;

"revised report" means a revised report, referred to in section 5 (3), for an initial landfill gas assessment.

Application

2 This regulation applies to landfill sites that accept municipal solid waste for disposal into the landfill site on or after January 1, 2009.

Prescribed class

3 For the purposes of section 76.2 of the Act, regulated landfill sites are a prescribed class of waste management facility.

Initial landfill gas generation assessment and report

4 (1) An owner or operator of a regulated landfill site must ensure that a qualified professional conducts an initial landfill gas generation assessment of the landfill site in accordance with subsection (2).

(2) The assessment referred to in subsection (1) must be conducted in accordance with the guidelines and include the following:

(a) the annual tonnage of municipal solid waste received for disposal into the landfill site in the calendar year immediately preceding the year in which the assessment is conducted;

(b) projections for the annual tonnage of municipal solid waste anticipated to be received for disposal into the landfill site in the calendar year of the assessment and in each of the 4 calendar years following the calendar year of the assessment;

(c) an estimate of the municipal solid waste in place at the landfill site at the end of the calendar year immediately preceding the calendar year in which the assessment is conducted;

(d) an estimate of the quantity of methane generated at the landfill site in the calendar year immediately preceding the calendar year in which the assessment is conducted;

(e) projections for methane anticipated to be generated annually at the landfill site in the calendar year of the assessment and in each of the 4 calendar years following the calendar year of the assessment.

(3) The qualified professional who conducts the assessment must complete an initial report setting out the following:

(a) the findings of the initial assessment, including the information described in subsection (2);

(b) copies of relevant records respecting annual tonnage of municipal solid waste received for disposal into the landfill site

(i) in the calendar year immediately preceding the year in which the assessment is conducted, and

(ii) in all years during which the landfill site has been in operation and for which records have been maintained;

(c) any other information requested in writing by the director;

(d) any other information required under the guidelines;

(e) certification by the qualified professional that the assessment meets the requirements set out in subsection (2).

(4) If a landfill gas generation assessment has been conducted for a landfill site before January 1, 2009, the requirement for an assessment under this section may be met if a qualified professional reviews the assessment and completes a report as described in subsection (3).

(5) The owner or operator of the landfill site must submit to the director a report required under this section as follows:

(a) if the quantity of municipal solid waste in place at the landfill site is 100 000 tonnes or more on or before January 1, 2009, no later than January 1, 2011;

(b) if the quantity of municipal solid waste in place at the landfill site reaches or exceeds 100 000 tonnes after January 1, 2009, on or before the later of

(i) March 31 of the year immediately following the year in which the quantity of municipal solid waste reaches or exceeds 100 000 tonnes, or

(ii) January 1, 2011;

(c) if the annual quantity of municipal solid waste received for disposal into the landfill site reaches or exceeds 10 000 tonnes on or after January 1, 2009, on or before the later of

(i) March 31 of the year immediately following the year in which the annual quantity of municipal solid waste received for disposal into the landfill site reaches or exceeds 10 000 tonnes, or

(ii) January 1, 2011.

Director may request further assessment

5 (1) The director may, within 60 days after receiving a report under section 4, request that the owner or operator of a landfill site conduct additional assessments of the landfill site for generation of landfill gas.

(2) If the director requests additional assessments of a landfill site, the owner or operator of the landfill site must ensure that a qualified professional conducts the additional assessments.

(3) The owner or operator of the landfill site must submit to the director, no later than 60 days after the date the director makes the request, a revised landfill gas generation assessment report setting out the following:

(a) the information resulting from the additional assessments;

(b) certification by the qualified professional that the additional assessments have been conducted in accordance with the director's request.

Assessment on request of director

6 (1) The director may, at any time, request that the owner or operator of a landfill site to which this regulation applies have a qualified professional

(a) conduct an assessment of the landfill site in accordance with section 4 (2), and

(b) complete a report as described under section 4 (3).

(2) The report required under this section must be submitted to the director no later than 180 days after the date the director requests the assessment.

Landfill gas management facilities design plan

7 (1) The owner or operator of a regulated landfill site that, as the result of an assessment conducted in accordance with this regulation, is estimated to generate 1 000 tonnes or more of methane in the calendar year immediately preceding the calendar year of the assessment must ensure that a landfill gas management facilities design plan is prepared for the landfill site.

(2) The plan required under this section must be prepared by a qualified professional in accordance with the guidelines and include the following information:

(a) a description of existing or planned methods, management practices and processes for landfill gas management at the landfill site;

(b) a plan for the installation, operation and maintenance of landfill gas management facilities at the landfill site, including a contingency plan for disruption in landfill gas management for scheduled or emergency maintenance or replacement of landfill gas management facilities;

(c) recommendations for optimizing landfill gas management at the landfill site;

(d) any other information required under the guidelines;

(e) any other information requested in writing by the director;

(f) certification by the qualified professional that the plan was prepared in accordance with the guidelines.

(3) The landfill gas management facilities design plan must be submitted to the director no later than one year after the date the report setting out the estimate was required to be submitted to the director.

(4) A landfill gas management facilities design plan that has been prepared for a landfill site before January 1, 2009 may be submitted to the director in substitution for the landfill gas management system design plan required under subsection (1) if a qualified professional certifies in writing that the landfill gas management system design plan prepared before January 1, 2009 meets the requirements set out in subsection (2).

(5) The owner or operator of a regulated landfill site that, as the result of an assessment conducted in accordance with this regulation, is estimated to generate less than 1 000 tonnes of methane gas in the calendar year immediately preceding the calendar year of the assessment may submit a plan to the director at any time.

Landfill gas management facilities

8 (1) In this section, and in section 11, **"accepted design plan"** means a landfill gas management facilities design plan that has been accepted by the director under section 18.

(2) The owner or operator of a landfill site for which there is an accepted design plan must

(a) install landfill gas management facilities in accordance with the accepted design plan, and

(b) implement management practices, processes and methods for landfill gas management in accordance with any guidelines respecting

(i) migration of landfill gas,

(ii) use of landfill covers,

(iii) operation of landfill gas management facilities,

(iv) landfill gas collection equipment,

(v) landfill gas flaring equipment, and

(vi) landfill gas management facilities maintenance, including the number of days annually that landfill gas management facilities may be shut down.

(3) The landfill gas management facilities and practices referred to in subsection (2) must be installed and implemented no later than 4 years after the date the landfill gas management facilities design plan is submitted to the director under section 7.

(4) The owner or operator of a landfill site where landfill gas management facilities are installed must ensure that

(a) a qualified professional certifies in writing to the director that the facilities were installed in accordance with the accepted design plan for the landfill site, and

(b) the facilities are operated and maintained in accordance with the accepted design plan for the landfill site.

Landfill gas management

9 (1) The owner or operator of a landfill site must ensure that landfill gas collected at the landfill site is flared in accordance with the guidelines unless the landfill gas is used for a purpose and in a manner that reduces emissions of methane to the atmosphere in an amount equivalent to the reduction that would be achieved by flaring the landfill gas.

(2) Nothing in the guidelines may require an owner or operator of a landfill site to use landfill gas as an alternative to flaring.

Notice of emergency shutdown

10 The owner or operator of a landfill site where landfill gas management facilities are shut down temporarily for emergency maintenance or replacement must notify the director within 24 hours of the shutdown by phone, fax or other electronic means.

Permanent shutdown of landfill gas management facilities

11 (1) At least 90 days before the date an owner or operator of a landfill site plans to cease operation of landfill gas management facilities, the owner or operator must submit to the director a shutdown report prepared by a qualified professional, setting out the supporting data used to calculate the quantity of methane generated per year at the landfill site.

(2) The shutdown report must include certification by a qualified professional that the quantity of methane generated at the landfill site per year, calculated in accordance with the methodology set out in the guidelines, is less than 500 tonnes.

(3) An owner or operator of a landfill site must continue to operate and maintain landfill gas management facilities in accordance with the accepted design plan for the landfill site until the director has accepted the shutdown report under section 18.

Monitoring and maintaining records

12 (1) An owner or operator of a regulated landfill site must monitor and maintain records respecting the following, each in the manner specified by the director:

(a) the quantity and sources of municipal solid waste received for disposal into the landfill site;

(b) if the owner or operator has monitored and analyzed the composition of the municipal solid waste received for disposal into the landfill site, the composition of the municipal solid waste received;

(c) any other matter required under the guidelines.

(2) If installation of landfill gas management facilities is required at the landfill site under section 8, the owner or operator of the landfill site must also maintain records respecting

(a) maintenance and shutdown of landfill gas management facilities installed and operated at the landfill site,

(b) the quantity and composition of gases collected at the landfill site, and

(c) the quantity and composition of landfill gas that is flared or used as an alternative to flaring.

(3) The owner or operator must ensure that the records required under this section are retained for a period of at least 10 years after they are made.

Production of records

13 On the written request of the director, an owner or operator of a landfill site must, within the time period specified by the director, produce the records referred to in section 12 to the director for inspection or copying.

Annual reports

14 (1) An owner or operator of a regulated landfill site must file an annual report with the director, in the manner and form required by the director, setting out the following information for the reporting period:

(a) the information described in section 12;

(b) a description of any organics diversion program used at the landfill site;

(c) any additional information requested in writing by the director.

(2) If installation of landfill gas management facilities is required at the landfill site under section 8, the annual report must include, in addition to the information required under subsection (1), the following information for the reporting period:

(a) the quantity and composition, determined in accordance with the methodology set out in the guidelines, of gases collected at the landfill site;

(b) the quantity and composition, determined in accordance with the methodology set out in the guidelines, of landfill gas that is flared or used as an alternative to flaring;

(c) if landfill gas is used as an alternative to flaring, a description of that use;

(d) a description of any periods when the landfill gas management facilities at the landfill site were shut down, and the reasons for the shut down;

(e) a description of any significant maintenance or operational problems encountered;

(f) the efficiency of any landfill gas management facilities used at the landfill site, including an evaluation of the existing efficiency of the facilities, the method and supporting data used to calculate the facilities' efficiency and the owner's or operator's plan for increasing the facilities' efficiency;

(g) municipal solid waste composition studies, if available;

(h) plans to be implemented at the landfill site in the next reporting year for

(i) modifications or other changes to landfill gas management facilities, and

(ii) periods when the landfill gas management facilities will be out of operation;

(i) any other information requested in writing by the director.

(3) An annual report required under this section must be submitted to the director

(a) if an operational certificate or permit has been issued for the landfill site, and the operational certificate or permit for the landfill site specifies a date for submission of an annual report, on or before that date, or

(b) if the operational certificate or permit for the landfill site does not specify a date for submission of an annual report, or an operational certificate or permit has not been issued for the landfill site, on or before March 31 of the year immediately following the year for which the report is prepared.

Supplementary assessments and reports

15 (1) If the estimate of methane generated annually at a landfill site is less than 1 000 tonnes in the calendar year immediately preceding the calendar year of an assessment under section 4, 5 or 6 or a supplementary assessment or review under this section, the owner or operator of the landfill site must, between January 1 and March 31 of the fifth calendar year following the calendar year of the previous assessment or review, ensure that a qualified professional does one of the following:

(a) conducts a supplementary assessment that includes

(i) the assessments required under section 4 (2) (a) to (c) and (e), and

(ii) an estimate of the quantity of methane generated at the landfill site in each of the 5 calendar years preceding the calendar year in which the supplementary assessment is conducted;

(b) reviews the previous assessment to determine whether there have been any material changes in the information since the previous report.

(2) A qualified professional who conducts a supplementary assessment or a review under subsection (1) must complete a supplementary report setting out

(a) in the case of an assessment under subsection (1) (a),

(i) the findings of the supplementary assessment, and

(ii) the information described in section 4 (3) (b) to (e), or

(b) in the case of a review under subsection (1) (b),

(i) a statement that there have been no material changes in the information since the previous report, or

(ii) the information that has changed from the previous report.

(3) The supplementary report must also include certification by the qualified professional that

(a) in the case of a supplementary assessment referred to in subsection (1) (a), the assessment was conducted in accordance with the guidelines and included the assessments required under subsection (1) (a), or

(b) in the case of a review referred to in subsection (1) (b), the information in the report is correct.

(4) The owner or operator of a landfill site must submit the supplementary report required under subsection (2) to the director no later than March 31 of the calendar year of the supplementary assessment or review.

Exception

16 Section 15 does not apply to the owner or operator of a landfill site for which a landfill gas management facilities design plan has been submitted under section 7 (5) and accepted by the director under section 18.

Additional information

17 (1) In this section, and in section 18, **"document"** means

(a) an initial report,

(b) a revised report,

(c) a report of an assessment conducted on the request of the director under section 5,

(d) a landfill gas management facilities design plan referred to in section 7,

(e) a shutdown report referred to in section 11 (2),

(f) an annual report referred to in section 14,

(g) a supplementary report referred to in section 15, and

(h) additional information provided under subsection (3).

(2) The director may, within 60 days after receiving a document, make a written request that the owner or operator of a landfill site provide additional information respecting the subject matter of the document as the director considers necessary.

(3) If the director requests additional information under subsection (2), the owner or operator of the landfill site must provide the additional information, in writing, to the director no later than 60 days after the date the director makes the request.

Director's acceptance of reports and plans

18 The director will be considered to have accepted a document submitted to the director under this regulation,

(a) in the case of a document for which no additional information is requested, 60 days after the document is submitted, or

(b) in the case of a document for which additional information is requested, 60 days after the additional information is submitted.

Substituted requirements

19 (1) The minister or a director, on his or her own initiative, may, by order, substitute a different requirement for a requirement contained in this regulation if, in the individual case, the minister or director considers that

(a) the substitution is necessary to protect the public or the environment, or

(b) the intent of the regulation is met by the substituted requirement.

(2) If the minister or a director makes a substitution under subsection (1), he or she may order that notification of the substitution be given to the public in the manner the minister or director specifies.

(3) A director, on application under section 20, may, by order, substitute a different requirement for a requirement contained in this regulation if he or she considers that, in the individual case, the intent of the regulation will be met by the substituted requirement.

Application for substituted requirement

20 (1) An owner or operator of a landfill site may apply for a substitution described in section 19 (3) by filing with a director a copy of a completed application in the form specified by the director.

(2) An owner or operator who makes an application under subsection (1) must do all of the following:

(a) within 15 days after the date the application is filed with the director, post a readable copy of the application in a conspicuous place at all main entrances to the landfill site;

(b) keep the copy posted for a period of not less than 30 days;

(c) publish notice of the application in the form approved by the director in one or more newspapers specified by the director;

(d) advise the director in writing of the date the copy of the application was posted under paragraph (a) and the date notice was published under paragraph (c).

(3) If directed to do so by a director, an owner or operator who makes an application under subsection (1) must

(a) serve a signed copy of the application on any person who, in the director's opinion, may be adversely affected by an environmental impact of the proposed substituted requirement, and

(b) display a copy of the application in one or more branch post offices of Canada Post Corporation specified by the director.

(4) A person who objects to a proposed substitution under this section may notify a director, stating the reasons for the person's objection, within 30 days after the occurrence of the later of the following events:

(a) the application is posted or published under subsection (2);

(b) the application is served or displayed under subsection (3).

(5) If directed to do so by a director, the applicant must consult in the manner directed with the person who, in the director's opinion, has reasonable objections to the proposed substitution to explain and clarify the intent of the application.

(6) An applicant must demonstrate to the satisfaction of a director that the substituted requirement requested meets the intent of the regulation.

(7) A director, on receipt of an application under this section, may

(a) request additional information from the applicant if the director considers the information necessary for the evaluation of the application, and

(b) after the 30 day period referred to in subsection (4) is ended, and having considered any information provided under that subsection,

(i) refuse to grant the substitution, or

(ii) grant any or all the requested substitutions to any or all the requirements of this regulation, for a definite or indefinite period of time, and subject to the conditions the director considers appropriate.

(8) On granting or refusing an application, a director must

(a) serve a signed copy of his or her decision on the applicant, and

(b) give notice of it to all persons who gave notice under subsection (4).

(9) A director may cancel or amend a decision made under this section

(a) at the request of the applicant, or

(b) whenever new information demonstrates to the satisfaction of the director that

(i) the applicant provided false or misleading material information in the application, or

(ii) the cancellation or amendment is necessary to ensure that the intent of the regulation is met.

2010 Legislative Session: 2nd Session, 39th Parliament
FIRST READING

HONOURABLE BLAIR LEKSTROM
MINISTER OF ENERGY, MINES AND PETROLEUM RESOURCES

BILL 17 — 2010
CLEAN ENERGY ACT

Contents

Explanatory Note

HER MAJESTY, by and with the advice and consent of the Legislative Assembly of the Province of British Columbia, enacts as follows:

Definitions

1 (1) In this Act:

"acquire", used in relation to the authority, means to enter into an energy supply contract;

"authority" has the same meaning as in section 1 of the *Hydro and Power Authority Act*;

"British Columbia's energy objectives" means the objectives set out in section 2;

"Burrard Thermal" means the gas-fired generation asset owned by the authority and located in Port Moody, British Columbia;

"clean or renewable resource" means biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource;

"demand-side measure" means a rate, measure, action or program undertaken

(a) to conserve energy or promote energy efficiency,

(b) to reduce the energy demand a public utility must serve, or

(c) to shift the use of energy to periods of lower demand,

but does not include

(d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or

(e) any rate, measure, action or program prescribed;

"electricity self-sufficiency" means electricity self-sufficiency as described in section 6 (2);

"expenditure for export" means the amount of an expenditure for the construction or extension of a plant or system or for an acquisition of electricity that is in addition to the amount the authority would have had to spend

(a) to achieve electricity self-sufficiency, and

(b) to undertake anything referred to in section 7 (1), except to the extent the expenditure is accounted for in paragraph (a);

"feed-in tariff program" means a program, that may be established under section 16, under which the authority offers to enter into energy supply contracts with persons generating electricity from clean or renewable resources using prescribed technologies in prescribed regions of British Columbia;

"greenhouse gas" has the same meaning as in section 1 of the *Greenhouse Gas Reduction Targets Act*;

"heritage assets" means

(a) any equipment or facilities for the transmission or distribution of electricity in respect of which, on the date on which this Act receives First Reading in the Legislative Assembly, a certificate of public convenience and necessity has been granted, or has been deemed to have been granted, to the authority or the transmission corporation under the *Utilities Commission Act*,

(b) generation and storage assets identified in Schedule 1 of this Act, and

(c) equipment and facilities that are for the transmission or distribution of electricity and that are identified in Schedule 1 of this Act;

"integrated resource plan" means an integrated resource plan required to be submitted under section 3;

"transmission corporation" means British Columbia Transmission Corporation.

(2) Words and expressions used but not defined in this Act or the regulations, unless the context otherwise requires, have the same meanings as in the *Utilities Commission Act*.

PART 1 — BRITISH COLUMBIA'S ENERGY OBJECTIVES

British Columbia's energy objectives

2 The following comprise British Columbia's energy objectives:

(a) to achieve electricity self-sufficiency;

(b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;

(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

(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;

(e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers;

(f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;

(g) to reduce BC greenhouse gas emissions

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

(ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

(iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

(iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

(v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;

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

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

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

(k) to encourage economic development and the creation and retention of jobs;

(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;

(m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British

Columbia's generation and transmission assets for the benefit of British Columbia;

(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;

(o) to achieve British Columbia's energy objectives without the use of nuclear power;

(p) to ensure the commission, under the *Utilities Commission Act*, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.

Integrated resource plans

3 (1) The authority must submit to the minister, in accordance with subsection (6), an integrated resource plan that is consistent with good utility practice and that includes all of the following:

(a) a description of the authority's forecasts, over a defined period, of its energy and capacity requirements to achieve electricity self-sufficiency;

(b) a description of what the authority plans to do to achieve electricity self-sufficiency and to respond to British Columbia's other energy objectives, including plans respecting

(i) the implementation of demand-side measures,

(ii) the construction or extension of facilities,

(iii) the acquisition of electricity from other persons, and

(iv) the use of rates, including rates to encourage

(A) energy conservation or efficiency,

(B) the use of energy during periods of lower demand,

(C) the reduction of the energy demand the authority must serve, or

(D) the development and use of electricity from clean or renewable resources;

(c) a description of the consultations carried out by the authority respecting the development of the integrated resource plan;

(d) a description of

(i) the expected export demand during a defined period,

(ii) the potential for British Columbia to meet that demand,

(iii) the actions the authority has taken to seek suitable opportunities for the export of electricity from clean or renewable resources, and

(iv) the extent to which the authority has arranged for contracts for the export of electricity and the transmission or other services necessary to facilitate those exports;

(e) if the authority plans to make an expenditure for export, a specification of the amount of the expenditure and a rationale for making it.

(2) In the first integrated resource plan the authority submits to the minister, and in any other integrated resource plan the minister by order specifies, the authority must include a description of the authority's infrastructure and capacity needs for electricity transmission for the period ending 30 years after the date the integrated resource plan is submitted.

(3) The description referred to in subsection (2) must include an assessment of the potential for developing, during the period referred to in subsection (2), grouped by geographic area, electricity generation from clean or renewable resources in British Columbia.

(4) The authority must carry out any consultations required by a regulation under section 35 (g) and submit a report to the minister, within the time prescribed, respecting those consultations.

(5) The authority must plan to rely on no energy and no capacity from Burrard Thermal, except in the case of emergency or as authorized by regulation.

(6) An integrated resource plan must be submitted

(a) within 18 months from the date this Part comes into force, and

(b) once every 5 years after the submission under paragraph (a), unless a submission date is prescribed for the purposes of this subsection, in which case an integrated resource plan must be submitted by the prescribed submission date.

(7) The authority may submit an amendment to an integrated resource plan approved under section 4, and section 4 applies to the submission.

(8) If the Lieutenant Governor in Council approves an amendment submitted under subsection (7), the approved amendment is to be considered a part of the approved integrated resource plan.

Approval and procurement

4 (1) After the minister receives an integrated resource plan, the Lieutenant Governor in Council, for the purposes of sections 44.2 (5.1), 46 (3.3) and 71 (2.21) and (2.51) of the *Utilities Commission Act*, may, by order,

(a) approve or reject the plan, and

(b) if the Lieutenant Governor in Council is satisfied that it is in the interests of British Columbians to pursue opportunities for export, require the authority, its subsidiaries or both to do the following:

(i) begin a process or processes by the time specified in the order to acquire the specified amount per year of energy and capacity from clean or renewable resources;

(ii) acquire the energy and capacity referred to in subparagraph (i) within the time specified in the order;

(iii) secure the necessary transmission capacity;

(iv) submit, for the purposes of subsection (2), a report to the minister respecting the expenditures for export resulting from compliance with subparagraphs (i) to (iii).

(2) In an order under subsection (1) (b) of this section, the Lieutenant Governor in Council may exempt the authority from sections 45 to 47 of the *Utilities Commission Act* with respect to anything to be done under subsection (1) (b) (iii) of this section.

(3) The authority and its subsidiaries and persons and their successors and assigns who enter into an energy supply contract as a result of a process referred to in subsection (1) (b) (i) of this section are exempt from section 71 of the *Utilities Commission Act* with respect to the energy supply contract.

(4) The Lieutenant Governor in Council, for the purposes of subsection (5) (a), may approve a report submitted under subsection (1) (b) (iv).

(5) In setting rates for the authority, the commission must ensure that the rates do not allow the authority to recover

(a) its expenditures for export as set out in a report approved by the Lieutenant Governor in Council under subsection (4), and

(b) any other expenditures for export.

Status report

5 (1) The authority must submit to the minister, by the time the minister requires, a status report respecting the authority's most recently approved integrated resource plan.

(2) The minister must make public a status report submitted under subsection (1) in the same manner and at the same time that the minister makes public a service plan under the *Budget Transparency and Accountability Act*.

Electricity self-sufficiency

6 (1) In this section:

"electricity supply obligations" means

(a) electricity supply obligations for which rates are filed with the commission under section 61 of the *Utilities Commission Act*, and

(b) any other electricity supply obligations that exist at the time this section comes into force,

determined by using the authority's prescribed forecasts of its energy requirements and peak load, taking into account demand-side measures, that are in an integrated resource plan approved under section 4;

"heritage energy capability" means the maximum amount of annual energy that the heritage assets that are hydroelectric facilities can produce under prescribed water conditions.

(2) The authority must achieve electricity self-sufficiency by holding,

(a) by the year 2016 and each year after that, the rights to an amount of electricity that meets the electricity supply obligations, and

(b) by the year 2020 and each year after that, the rights to 3 000 gigawatt hours of energy, in addition to the amount of electricity referred to in paragraph (a), and the capacity required to integrate that energy solely from electricity generating facilities within the Province,

(c) assuming no more in each year than the heritage energy capability, and

(d) relying on Burrard Thermal for no energy and no capacity, except as authorized by regulation.

(3) The authority must remain capable of meeting its electricity supply obligations from the electricity referred to in subsection (2) (a) and (b), except to the extent the authority may be permitted, by regulation, to enter into contracts in the prescribed circumstances and on the prescribed terms and conditions.

(4) A public utility, in planning in accordance with section 44.1 of the *Utilities Commission Act* for

(a) the construction or extension of generation facilities, and

(b) energy purchases,

must consider British Columbia's energy objective to achieve electricity self-sufficiency.

Exempt projects, programs, contracts and expenditures

7 (1) The authority is exempt from sections 45 to 47 and 71 of the *Utilities Commission Act* to the extent applicable, and from any other sections of that Act that the minister may specify by regulation, with respect to the following projects, programs, contracts and expenditures of the authority, as they may be further described by regulation:

(a) the Northwest Transmission Line, a 287 kilovolt transmission line between the Skeena substation and Bob Quinn Lake, and related facilities and contracts;

(b) Mica Units 5 and 6, a project to install two additional turbines and related works and equipment at Mica;

(c) Revelstoke Unit 6, a project to install an additional turbine and related works and equipment at Revelstoke;

(d) Site C, a project to build a third dam on the Peace River in northeast British Columbia to provide approximately

(i) 4 600 gigawatt hours of energy each year, and

(ii) 900 megawatts of capacity;

(e) a bio-energy phase 2 call to acquire up to 1 000 gigawatt hours per year of electricity;

(f) one or more agreements with pulp and paper customers eligible for funding under Canada's Green Transformation Program under which agreement or agreements the authority acquires, in aggregate, up to 1 200 gigawatt hours per year of electricity;

(g) the clean power call request for proposals, issued on June 11, 2008, to acquire up to 5 000 gigawatt hours per year of electricity from clean or renewable resources;

(h) the standing offer program described in section 15;

(i) the feed-in tariff program described in section 16;

(j) the actions taken to comply with section 17 (2) and (3);

(k) the program described in section 17 (4).

(2) The persons and their successors and assigns who enter into an energy supply contract with the authority related to anything referred to in subsection (1) are exempt from section 71 of the *Utilities Commission Act* with respect to the energy supply contract.

(3) The commission must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent the authority from doing anything referred to in subsection (1).

Rates

8 (1) In setting rates under the *Utilities Commission Act* for the authority, the commission must ensure that the rates allow the authority to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to

(a) the achievement of electricity self-sufficiency, and

(b) a project, program, contract or expenditure referred to in section 7 (1), except

(i) to the extent the expenditure is accounted for in paragraph (a), and

(ii) for costs, prescribed for the purposes of this section, respecting the feed-in tariff program.

(2) Subject to subsection (1) of this section, the commission must set under the *Utilities Commission Act* a rate proposed by the authority with respect to the project referred to in section 7 (1) (a) of this Act.

(3) The commission must not, except on application by the authority, cancel, suspend or amend a rate set in accordance with subsection (2).

(4) The authority must provide to the minister, in accordance with the regulations, an annual report comparing the electricity rates charged by the authority with electricity rates charged by public utilities in other jurisdictions in North America, including an assessment of the extent to which the authority's electricity rates continue to be competitive with those other rates.

Domestic long-term sales contracts

9 The authority must establish, in accordance with the regulations, a program to develop potential offers respecting domestic long-term sales contracts for availability to prescribed classes of customers on prescribed terms, including terms respecting price, for prescribed volumes of energy over prescribed periods.

PART 2 — PROHIBITIONS

Two-rivers system development

10 In this Part:

"approval" includes a certificate, licence, permit or other authorization;

"prohibited projects" means

(a) a project of the authority, referred to in Schedule 2 of this Act, for electricity generation on a stream, and

(b) a project for electricity generation on a stream with a storage capability in excess of a prescribed storage capability,

but does not include the two-rivers projects;

"stream" has the same meaning as in section 1 of the *Water Act*;

"two-rivers projects" means

(a) the authority's facilities, on the Peace River and the Columbia River System, existing on the date this section comes into force and upgrades or extensions to those facilities, and

(b) the project commonly known as Site C.

Project prohibitions

11 (1) Despite any other enactment, a minister, or an employee or agent of the government or of a municipality or regional district, must not issue an approval under an applicable enactment for a person to

(a) undertake a prohibited project, or

(b) construct all or part of the facilities of a prohibited project.

(2) Despite any other enactment, an approval under another enactment is without effect if it is issued contrary to subsection (1).

Prohibited acquisitions

12 (1) In this section:

"facility" means a facility for the generation of electricity and any transmission or distribution equipment to deliver that electricity to the point of interconnection with the authority's integrated service area;

"protected area" means

(a) a park, recreation area, or conservancy, as defined in section (1) of the *Park Act*,

(b) an area established under the *Environment and Land Use Act* as a park or protected area, or

(c) an area established or continued as an ecological reserve under the *Ecological Reserve Act* or by the *Protected Areas of British Columbia Act*.

(2) The authority must not make an offer to acquire electricity from a person whose proposed facility is to be located, in whole or in part, in a protected area, unless the location is permitted under the enactments referred to in the definition of "protected area" in subsection (1).

(3) A person referred to in subsection (2) must not offer to sell electricity to the authority.

Burrard Thermal

13 The authority must not operate Burrard Thermal, except

(a) in the case of emergency,

(b) to provide transmission support services, or

(c) as authorized by regulation.

PART 3 — PRESERVING HERITAGE ASSETS

Sale of heritage assets prohibited

14 (1) The authority must not sell or otherwise dispose of the heritage assets.

(2) Nothing in subsection (1) prevents the authority from disposing of heritage assets if the assets disposed of are no longer used or useful for their intended purpose, or they are to be replaced with one or more assets that will perform similar functions.

PART 4 — STANDING OFFER AND FEED-IN TARIFF PROGRAMS

Standing offer program

15 (1) In this section:

"eligible facility" means a generation facility that

(a) either

(i) has only one generator and the generator's nameplate capacity is less than or equal to the maximum nameplate capacity or has more than one generator and the total nameplate capacity of all of them is a capacity less than or equal to the maximum nameplate capacity, or

(ii) meets the prescribed requirements, and

(b) either

(i) is a high-efficiency cogeneration facility, or

(ii) generates energy by means of a prescribed technology or from clean or renewable resources,

but does not include a prescribed generation facility or class of generation facilities;

"maximum nameplate capacity" means 10 megawatts or, if another capacity is prescribed for the purposes of this section, the prescribed capacity.

(2) The authority must establish and, except in the prescribed circumstances, maintain a standing offer program to acquire electricity from eligible facilities.

(3) The authority may establish, in accordance with the prescribed requirements, if any, the criteria, terms and conditions on which offers under the standing offer program under subsection (2) are to be made.

Feed-in tariff program

16 (1) To facilitate the achievement of one or more of British Columbia's energy objectives, the Lieutenant Governor in Council, by regulation, may require the authority to establish a feed-in tariff program.

(2) If the authority is required to establish a feed-in tariff program, the authority may establish, in accordance with the prescribed requirements, if any, the criteria, terms and conditions under which offers may be made under the feed-in tariff program.

(3) The authority may not enter into an energy supply contract as a result of an offer made under the feed-in tariff program if the energy supply contract, by itself or in aggregate with other energy supply contracts entered into under the feed-in tariff program, would result in an expenditure that exceeds the prescribed amount in the prescribed period.

(4) Without limiting section 34 (2) (c),

(a) requirements prescribed by the Lieutenant Governor in Council, and

(b) criteria, terms and conditions established by the authority

made for the purpose of subsection (2) may be made with respect to different regions, prices and technologies.

PART 5 — ENERGY EFFICIENCY MEASURES AND GREENHOUSE GAS REDUCTIONS

Smart meters

17 (1) In this section:

"private dwelling" means

(a) a structure that is occupied as a private residence, or

(b) if only part of a structure is occupied as a private residence, that part of the structure;

"smart grid" means the prescribed equipment;

"smart meter" means a meter that meets the prescribed requirements, and includes related components, equipment and metering and communication infrastructure that meet the prescribed requirements.

(2) Subject to subsection (3), the authority must install and put into operation smart meters and related equipment in accordance with and to the extent required by the regulations.

(3) The authority must complete all obligations imposed under subsection (2) by the end of the 2012 calendar year.

(4) The authority must establish a program to install and put into operation a smart grid in accordance with and to the extent required by the regulations.

(5) The authority may, by itself, or by its engineers, surveyors, agents, contractors, subcontractors or employees, enter on any land, other than a private dwelling, without the consent of the owner, for a purpose relating to the use, maintenance, safeguarding, installation, replacement, repair, inspection, calibration or reading of its meters, including smart meters, or of its smart grid.

(6) If a public utility, other than the authority, makes an application under the *Utilities Commission Act* in relation to smart meters, other advanced meters or a smart grid, the commission, in considering the application, must consider the government's goal of having smart meters, other advanced meters and a smart grid in use with respect to customers other than those of the authority.

Greenhouse gas reduction

18 (1) In this section, **"prescribed undertaking"** means a project, program, contract or expenditure that is in a class of projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in British Columbia.

(2) In setting rates under the *Utilities Commission Act* for a public utility carrying out a prescribed undertaking, the commission must set rates that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking.

(3) The commission must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent a public utility referred to in subsection (2) from carrying out a prescribed undertaking.

(4) A public utility referred to in subsection (2) must submit to the minister, on the minister's request, a report respecting the prescribed undertaking.

(5) A report to be submitted under subsection (4) must include the information the minister specifies and be submitted in the form and by the time the minister specifies.

Clean or renewable resources

19 (1) To facilitate the achievement of British Columbia's energy objective set out in section 2 (c), a person to whom this subsection applies

(a) must pursue actions to meet the prescribed targets in relation to clean or renewable resources, and

(b) must use the prescribed guidelines in planning for

(i) the construction or extension of generation facilities, and

(ii) energy purchases.

(2) Subsection (1) applies to

(a) the authority, and

(b) a prescribed public utility, if any, and a public utility in a class of prescribed public utilities, if any.

PART 6 — FIRST NATIONS CLEAN ENERGY BUSINESS FUND

First Nations Clean Energy Business Fund

20 (1) In this section:

"first nation" means

(a) a band, as defined in the *Indian Act* (Canada), and

(b) an aboriginal governing body, however organized and established by aboriginal people;

"power project" means an electricity generation or transmission project

(a) that is in a class of projects prescribed for the purposes of this section, other than a project of any organization in the government reporting entity, as defined in the *Budget Transparency and Accountability Act*,

(b) for which a licence, if applicable, under the *Water Act* for a power purpose, as defined section 1 of that Act, is issued after the date this section comes into force, and

(c) for which a prescribed authorization, if applicable, under an enactment respecting land is granted after this section comes into force;

"special account" means the special account, as defined in section 1 of the *Financial Administration Act*, established under subsection (2) of this section.

(2) A special account, to be known as the First Nations Clean Energy Business Fund special account, is established.

(3) The initial balance of the special account is an amount, not to exceed $5 million, prescribed by Treasury Board.

(4) The balance of the special account is increased by

(a) any other amount received by the government for payment into the account, and

(b) a prescribed percentage of the prescribed land and water revenues the government derives from power projects.

(5) Despite section 21 (3) of the *Financial Administration Act*, the minister, in accordance with a spending plan approved by Treasury Board, may pay an amount of money out of the special account for any of the following purposes:

(a) to share the revenues referred to in subsection (4) (b), up to a prescribed percentage of the revenue, under an agreement or agreements with one or more first nations;

(b) to facilitate the participation of first nations and aboriginal people in the clean energy sector;

(c) to pay the costs of administering the special account.

PART 7 — TRANSMISSION CORPORATION

Division 1 — Transfer of Property, Shares and Obligations

Definitions

21 In this Division:

"excluded contract" means a contract that was entered into, assumed by or assigned to the transmission corporation and that is governed by the law of a jurisdiction other than British Columbia;

"excluded permit" means a permit, approval, registration, authorization, licence, exemption, order or certificate issued, granted or provided to the transmission corporation under the law of a jurisdiction other than British Columbia;

"included contract" includes any contract entered into, assumed by or assigned to the transmission corporation, but does not include an excluded contract;

"included permit" includes a permit, approval, registration, authorization, licence, exemption, order or certificate, including a certificate of public convenience and necessity under the *Utilities Commission Act*, but does not include an excluded permit;

"right", in relation to a right held by the authority or the transmission corporation, includes a right under a trust, a cause of action and a claim.

Transfer of property

22 (1) Subject to subsection (2) and despite any enactment or law to the contrary, on the coming into force of this Part, all of the transmission corporation's rights, property, assets, included contracts and included permits are transferred to and vested in the authority.

(2) Subsection (1) does not apply to excluded contracts and excluded permits.

(3) Despite any enactment or law to the contrary, on the coming into force of this Part, the shares of the transmission corporation are transferred to and vested in the authority.

(4) The shares transferred to and vested in the authority under subsection (3) must not be sold or otherwise disposed of, but may be surrendered for cancellation.

(5) Despite any enactment or law to the contrary,

(a) the transfer and vesting effected by subsections (1) and (3) take effect without

(i) the execution or issue of any record, or

(ii) any registration or filing of this Act or any other record in or with any registry or other office,

(b) the transfer and vesting effected by subsections (1) and (3) take effect despite

(i) any prohibition on all or any part of the transfer and vesting, and

(ii) the absence of any consent or approval that is or may be required for all or any part of the transfer and vesting,

(c) if any right, property, asset, included contract or included permit referred to in subsection (1) is registered or otherwise recorded in the name of the transmission corporation, the registration or record may remain but is deemed, for all purposes of this and all other enactments and law, to reflect that the right, property, asset, included contract or included permit is owned by and vested in or held by the authority, and

(d) in any record in or by which the authority deals with a right, property, asset, included contract or included permit referred to in subsection (1), it is sufficient to cite this Act as effecting and confirming the transfer from the transmission corporation to the authority of the included contract or included permit or of the title to the right, property or asset and the vesting of that title in the authority.

(6) For the purposes of this section, assets that become assets of the authority under this section include records and parts of records, and, without limiting this, all of the records and parts of records of the transmission corporation are transferred to and become the records of the authority on the coming into force of this Part.

(7) Without limiting subsection (5) (c) of this section, or section 383.1 of the *Land Title Act*, if a right, property or asset referred to in subsection (1) of this section is registered or recorded in the name of the transmission corporation,

(a) the authority may, in its own name,

(i) effect a transfer, charge, encumbrance or other dealing with the right, property or asset, and

(ii) execute any record required to give effect to that transfer, charge, encumbrance or other dealing, and

(b) an official

(i) who has authority over a registry or office, including, without limitation, the personal property registry and a land title office, in which title to or interests in the right, property or asset is registered or recorded, and

(ii) to whom a record referred to in paragraph (a) (ii) executed by or on behalf of the authority is submitted in support of the transfer, charge, encumbrance or other dealing

must give the record the same effect as if it had been duly executed by the transmission corporation.

Transfer of obligations and liabilities

23 On the coming into force of this Part, all obligations and liabilities of the transmission corporation, except for obligations and liabilities under an excluded contract or excluded permit,

(a) are transferred to and assumed by the authority,

(b) become the authority's obligations and liabilities,

(c) cease to be obligations and liabilities of the transmission corporation, and

(d) may be enforced against the authority as if the authority had incurred them.

Records of transferred assets and liabilities

24 (1) Subject to subsection (2), a reference to the transmission corporation in any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate that relates to anything transferred to the authority under this Part, is deemed to be a reference to the authority.

(2) If, under this Part, a part of a right, property, asset, obligation or liability is transferred to the authority, any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate that relates to anything transferred to the authority under this Part, is deemed to be amended to reflect the authority's interests in that right, property, asset, obligation or liability.

Transfer is not a default

25 Despite any provision to the contrary in any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate, the transfer to the authority of a right, property, asset, included contract, included permit, share, obligation or liability under sections 22 and 23 does not constitute a breach or contravention of, or an event of default under, or confer a right to terminate the document, and, without limiting this, does not entitle any person who has an interest in the right, property, asset, included contract, included permit, share, obligation or liability to claim any damages, compensation or other remedy.

Legal proceedings

26 (1) Any legal proceeding being prosecuted or pending by or against the transmission corporation on the date this Part comes into force may be prosecuted, or its prosecution may be continued, by or against the authority, and may not be prosecuted or continued against the transmission corporation.

(2) A conviction against the transmission corporation may be enforced against the authority, and may not be enforced against the transmission corporation.

(3) A ruling, order or judgment in favour of or against the transmission corporation may be enforced by or against the authority, and may not be enforced by or against the transmission corporation.

(4) A cause of action or claim against the transmission corporation existing on the date this Part comes into force must be prosecuted against the authority.

(5) Subject to subsections (1) to (4), a cause of action, claim or liability to prosecution existing on the date this Part comes into force is unaffected by anything done under this Part.

Division 2 — Employees

Definitions

27 In this Division:

"adjustment plan" means an adjustment plan under section 54 of the *Labour Relations Code*;

"collective agreement" has the same meaning as in section 1 (1) of the *Labour Relations Code*.

Transfer of employees

28 (1) It is deemed that the persons who were, immediately before the coming into force of this Part, employees of the transmission corporation are, on the coming into force of this Part, transferred to and become employees of the authority.

(2) A question or difference between the authority and

(a) a transferred employee who is a member of a unit of employees for which a trade union has been certified under the *Labour Relations Code*, or

(b) a trade union representing transferred employees, respecting the application of the *Labour Relations Code*, or the interpretation or application of this Division, may be referred to the Labour Relations Board in accordance with the procedure set out in the *Labour Relations Code* and its regulations.

(3) The Labour Relations Board may decide a question or difference referred to in subsection (2) in any of the ways, and by applying any of the remedies, available under the *Labour Relations Code*.

(4) On the date this Part comes into force, in respect of employees who are members of units of employees for which a trade union has been certified under the *Labour Relations Code*, the authority is the successor employer of those employees for the purposes of section 35 of the *Labour Relations Code*, without prejudice to the authority's right to apply for consolidation or merger of the bargaining units.

(5) If the authority or any trade union representing transferred employees makes an application to the Labour Relations Board to consolidate or merge the bargaining units representing transferred employees into a single bargaining unit for each trade union, the Labour Relations Board must consider that application having regard to the principles of business efficiency and without reference to the labour relations history at the authority or the transmission corporation relating to the presence of more than one bargaining unit for each trade union.

Continuous employment

29 (1) The transfer of a transferred employee does not constitute a termination of the transferred employee's employment for the purposes of

(a) an applicable collective agreement,

(b) any employment contract involving the transferred employee, and

(c) the *Employment Standards Act*.

(2) A transferred employee who is not subject to a collective agreement is deemed to have been employed by the authority without interruption in service.

(3) The service, with the transmission corporation, of a transferred employee who is not subject to a collective agreement is deemed to be service with the authority for the purpose of determining probationary periods and benefits, and any other employment related entitlements, under

(a) the *Employment Standards Act*,

(b) any other enactment, and

(c) any employment contract.

(4) For the purposes of seniority, a transferred employee who is subject to a collective agreement is deemed to have been employed by the authority without interruption in service, unless the authority and the trade union representing the transferred employee have agreed to other seniority terms in an adjustment plan within 60 days after notice under section 54 of the *Labour Relations Code* is given, in which case the applicable terms respecting seniority in the adjustment plan apply.

(5) The service, with the transmission corporation, of a transferred employee who is subject to a collective agreement is deemed to be service with the authority for the purpose of determining probationary periods and benefits, and any other employment related entitlements, under

(a) the *Employment Standards Act*,

(b) any other enactment, and

(c) any collective agreement,

unless the authority and the trade union representing the transferred employee have agreed to other probationary periods, benefits and entitlements in an adjustment plan within 60 days after notice under section 54 of the *Labour Relations Code* is given, in which case the applicable terms respecting probationary periods, benefits and entitlements in the adjustment plan apply.

(6) A transferred employee is deemed not to have been constructively dismissed solely by virtue of the transfer under section 28.

(7) Nothing in this Part

(a) prevents the employment of a transferred employee from being lawfully terminated after the transfer under section 28,

(b) prevents any term or condition of the employment of a transferred employee from being lawfully changed after the transfer under section 28, or

(c) removes any right or remedy of a person who is terminated after the transfer under section 28 or in respect of whom a term or condition of employment has been changed after the transfer under section 28.

Pensions

30 (1) For the purposes of the *Pension Benefits Standards Act*, the transfer of a transferred employee does not constitute a termination of membership in the transmission corporation's registered pension plan, or any other pension arrangement sponsored by the transmission corporation.

(2) Despite section 36 (1) of the *Hydro and Power Authority Act*, the authority does not require the approval of the Lieutenant Governor in Council to amend the authority's registered pension plan to implement the provisions of this Part, including the authority's assumption of all liability for the pension benefits payable under the transmission corporation's registered pension plan.

(3) Despite any enactment or law to the contrary, on the coming into force of this Part, all of the rights, property and assets that comprise

(a) the balance of fund account of the pension fund of the transmission corporation's registered pension plan are transferred to and vested in the balance of fund account of the pension fund of the authority's registered pension plan, and

(b) the index reserve account and past service index reserve account of the pension fund of the transmission corporation's registered pension plan are transferred to and vested in the index reserve account of the pension fund of the authority's registered pension plan,

and the resulting pension fund must be held by the trustee of the pension fund of the authority's registered pension plan.

(4) Section 22 (5) applies to the transfer and vesting effected by subsection (3) of this section.

Division 3 — General

Commission subject to direction

31 (1) The minister, by regulation, may issue a direction to the commission with respect to the exercise of powers and the performance of duties of the commission regarding any matter relating to a transfer made under this Part or to the service or rates referred to in section 32.

(2) The commission must comply with a direction issued under subsection (1) despite

(a) any provision of, or regulation under, the *Utilities Commission Act*, except any direction issued under section 3 of that Act, and

(b) any previous decision of the commission.

(3) This section is repealed on July 1, 2011.

Utilities Commission Act

32 (1) No approval, authorization, permit, certificate, exemption, permission, registration or order is required under the *Utilities Commission Act* with respect to

(a) the transmission corporation's ceasing to provide the service referred to in subsection (2) (a), or

(b) any transfer under this Part.

(2) The authority is deemed to have all the approvals, authorizations, permits, certificates, exemptions, permissions, registrations or orders that, under the *Utilities Commission Act*, are or may be required to continue

(a) to provide the service the transmission corporation provided immediately before the coming into force of this Part, and

(b) to charge, collect and enforce the rates the transmission corporation charged, collected and enforced immediately before the coming into force of this Part.

(3) The commission must not, except on application by the authority, cancel, suspend or amend

(a) any approval, authorization, permit, exemption, permission, registration, order or certificate, except for the certificate issued by commission Order C-4-08, that, under the *Utilities Commission Act*, the authority requires to provide the service and to charge, collect and enforce the rates referred to in subsection (2), or

(b) the service or rates referred to in subsection (2).

(4) Subsection (3) is repealed on July 1, 2011.

Designated agreements

33 On the coming into force of this Part, the agreements designated under section 3 of the *Transmission Corporation Act* have no force or effect.

PART 8 — REGULATIONS

Division 1 — Regulations by Lieutenant Governor in Council

General

34 (1) The Lieutenant Governor in Council may make regulations referred to in section 41 of the *Interpretation Act*.

(2) In making a regulation under this Act, the Lieutenant Governor in Council may do one or more of the following:

(a) delegate a matter to a person;

(b) confer a discretion on a person;

(c) make different regulations for different persons, places, things, decisions, transactions or activities.

Regulations

35 Without limiting section 34 (1), the Lieutenant Governor in Council may make regulations as follows:

(a) respecting forecasts for the purposes of the definition of "electricity supply obligations" in section 6 (1);

(b) adding a heritage asset to Schedule 1 of this Act;

(c) prescribing water conditions for the purposes of the definition of "heritage energy capability" in section 6 (1);

(d) modifying or adding to British Columbia's energy objectives, except for the objective specified in section 2 (g);

(e) for the purposes of sections 44.1, 44.2, 46 and 71 of the *Utilities Commission Act*, respecting the application of British Columbia's energy objectives to public utilities other than the authority;

(f) establishing factors or guidelines the commission must follow in respect of British Columbia's energy objectives, including guidelines regarding the relative priority of the objectives set out in section 2;

(g) respecting consultations the authority must carry out in relation to

(i) the development of an integrated resource plan and of an amendment to an integrated resource plan,

(ii) an integrated resource plan submitted under section 3 (6), and

(iii) an amendment to an integrated resource plan submitted under section 3 (7);

(h) prescribing submission dates for the purposes of section 3 (6);

(i) respecting the authority's obligation under section 6 (3), including, without limitation, regulations permitting the authority to enter into contracts respecting the electricity referred to in section 6 (2) (a) and (b) and prescribing the terms and conditions on which, and the volume of electricity about which, the contracts may be entered into;

(j) respecting the program referred to in section 9, including prescribing classes of customers and terms;

(k) prescribing storage capability for the purposes of the definition of "prohibited projects" in section 10, including, without limitation, prescribing storage capability in terms of time, impoundment, mechanism or area;

(l) respecting the standing offer program to be established under section 15, including, without limitation, regulations that

(i) prescribe requirements, technologies, generation facilities and classes of generation facilities for the purposes of the definition of "eligible facility" in section 15 (1),

(ii) prescribe a capacity for the purposes of the definition of "maximum nameplate capacity" in section 15 (1),

(iii) prescribe circumstances for the purposes of section 15 (2), and

(iv) prescribe requirements for the purposes of section 15 (3);

(m) respecting the feed-in tariff program that may be established under section 16, including, without limitation, regulations that

(i) prescribe regions and technologies for the purposes of the definition of "feed-in tariff program" in section 1 (1),

(ii) require the authority to establish the feed-in tariff program,

(iii) prescribe requirements for the purposes of section 16 (2),

(iv) prescribe amounts and periods for the purposes of section 16 (3), and

(v) prescribe costs for the purposes of section 8 (1) (b);

(n) for the purposes of the definition of "prescribed undertaking" in section 18, prescribing classes of projects, programs, contracts or expenditures that encourage

(i) the use of

(A) electricity, or

(B) energy directly from a clean or renewable resource

instead of the use of other energy sources that produce higher greenhouse gas emissions, or

(ii) the use of natural gas, hydrogen or electricity in vehicles, and the construction and operation of infrastructure for natural gas or hydrogen fueling or electricity charging.

Division 2 — Regulations by Minister

General

36 (1) In making a regulation under this Act, the minister may do one or more of the following:

(a) delegate a matter to a person;

(b) confer a discretion on a person;

(c) make different regulations for different persons, places, things, decisions, transactions or activities.

(2) The minister may make a regulation defining, for the purposes of this Act, a word or expression used but not defined in this Act.

Regulations

37 The minister may make regulations as follows:

(a) prescribing resources for the purposes of the definition of "clean or renewable resource" in section 1 (1);

(b) prescribing exclusions for the purposes of the definition of "demand-side measure" in section 1 (1);

(c) authorizing the authority for the purposes of sections 3 (5), 6 and 13;

(d) describing the projects, programs, contracts and expenditures referred to in section 7 (1), including, without limitation, by specifying the property, interests, rights, activities, contracts and rates that comprise the projects, programs, contracts and expenditures;

(e) specifying sections of the *Utilities Commission Act* for the purposes of section 7 (1);

(f) respecting reports to be provided to the minister by the authority under section 8 (4), including, without limitation, regulations respecting the jurisdictions with which comparisons are to be made, the rate classes to be considered, the factors to be used in making the comparisons and conducting the assessments, and the meaning to be given to the word "competitive";

(g) for the purposes of section 17, respecting smart meters and smart-grids and their installation, including, without limitation,

(i) prescribing the types of smart meters to be installed, including the features or functions each meter must have or be able to perform,

(ii) prescribing types of smart grids to be installed, including, without limitation, equipment to detect unauthorized use or consumption of electricity, equipment to facilitate distributed generation and associated telecommunication and back-up systems, and

(iii) prescribing the classes of users for whom smart meters must be installed, and, without limiting section 36 (1) (c), requiring the authority to install different types of smart meters for different classes of users;

(h) prescribing targets, guidelines, public utilities and classes of public utilities for the purposes of section 19;

(i) issuing a direction for the purposes of section 31.

Division 3 — Regulations by Treasury Board

Regulations

38 Treasury Board may make regulations as follows:

(a) prescribing classes of projects and authorizations for the purposes of the definition of "power project" in section 20 (1), including, without limitation, prescribing classes of projects by reference to whether, or the extent to which, a project is a project of any organization of the government reporting entity, within the meaning of that definition;

(b) prescribing amounts and percentages for the purposes of section 20 (3), (4) (b) and (5) (a).

PART 9 — TRANSITION

Transition

39 (1) The Lieutenant Governor in Council may make regulations considered appropriate for the purpose of more effectively bringing this Act into operation, and to remedy any transitional difficulties encountered in doing so, and for that purpose, may make regulations disapplying or varying any provision of this Act.

(2) Subject to subsection (3), this section is repealed on the date that is 2 years after the coming into force of this section and, on this section's repeal, any regulations made under it are also repealed.

(3) The Lieutenant Governor in Council, by regulation, may substitute for the date referred to in subsection (2) a date that is no later than 3 years after the coming into force of this section.

PART 10 — CONSEQUENTIAL AMENDMENTS

BC Hydro Public Power Legacy and Heritage Contract Act

40 Section 1 of the BC Hydro Public Power Legacy and Heritage Contract Act, S.B.C. 2003, c. 86, is amended by repealing the definition of* "protected assets"*.

41 Section 2 is repealed.

42 Section 4 (2) (a) is amended by striking out ", the *Hydro and Power Authority Act* and the *Transmission Corporation Act*;***" and substituting "***and the *Hydro and Power Authority Act*;***".***

43 The Schedule is repealed.

Environmental Assessment Act

44 Section 11 (2) (b) of the Environmental Assessment Act, S.B.C. 2002, c. 43, is amended by adding "**, including potential cumulative environmental effects" after "**assessment***".***

Financial Information Act

45 Schedule 1 of the Financial Information Act, R.S.B.C. 1996, c. 140, is amended by striking out "**Transmission Corporation Act".***

Forest Act

46 Section 47.6 (2.11) (b) of the Forest Act, R.S.B.C. 1996, c. 157, as enacted by section 18 (c) of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, S.B.C. 2008, c. 20, is amended by striking out everything after "**has received notification" and substituting "**under section 79.1.***"***

47 Section 47.7 (f) (ii) is amended by adding "**other than a forestry licence to cut issued under section 47.6 (2.11)" after "**forestry licence to cut***".***

48 Section 47.72, as enacted by section 20 of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, is amended

> ***(a) in subsection (1) (f) by striking out "**a regulation made under section 151.6 (2).***" and substituting "**section 79.1.***", and***
>
> ***(b) in subsection (2) by striking out "**of harvest completion***" and substituting "**in accordance with section 79.1***" and by striking out "**a regulation made under section 151.6 (2)***" and substituting "**section 79.1.***"***

49 Section 47.73, as enacted by section 20 of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, is amended by striking out everything after "**gave the notification" and substituting "**in accordance with section 79.1.***"***

50 Section 47.9, as enacted by section 22 of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, is amended by striking out "**a regulation made under section 151.6 (2)" and substituting "**section 79.1***".***

51 The following Division is added after section 79:

Division 4.1 — Miscellaneous

Order respecting notice

79.1 (1) During the term of an agreement under section 12, the minister may order that the agreement holder must notify the minister, in accordance with the requirements specified in the order, whether the agreement holder has abandoned or intends to abandon any rights the agreement holder has in respect of Crown timber that has been cut under the agreement but has not been removed from an area specified in the order.

(2) If an agreement holder referred to in subsection (1) notifies the minister that the agreement holder has abandoned or intends to abandon the rights referred to in subsection (1), the minister may order the agreement holder not to destroy or otherwise deal with the Crown timber referred to in that subsection.

(3) If an agreement holder referred to in subsection (1) notifies the minister that the agreement holder has not abandoned and does not intend to abandon the rights referred to in subsection (1), the minister may order the agreement holder not to destroy the Crown timber referred to in that subsection, if the minister is satisfied that a market exists for that Crown timber.

(4) A person to whom an order under this section has been given must comply with the order.

Freedom of Information and Protection of Privacy Act

52 Schedule 2 of the Freedom of Information and Protection of Privacy Act, R.S.B.C. 1996, c. 165, is amended by striking out the following:

Public Body:	British Columbia Transmission Corporation
Head:	Chair *.*

Hydro and Power Authority Act

53 Section 1 of the Hydro and Power Authority Act, R.S.B.C. 1996, c. 212, is amended in the definition of "power" by adding ", except in sections 12 (1) and 38 (2),***" before "***includes energy***".***

54 Section 12 (1) is repealed and the following substituted:

(1) Subject to this Act and the regulations, the authority has the capacity and the rights, powers and privileges of an individual of full capacity and, in addition, has

(a) the power to amalgamate in any manner with a firm or person, and

(b) any other power prescribed.

(1.1) The authority's purposes are

(a) to generate, manufacture, conserve, supply, acquire and dispose of power and related products,

(b) to supply and acquire services related to anything in paragraph (a), and

(c) to do other things as may be prescribed.

(1.2) The authority may not engage in activities or classes of activities prescribed for the purposes of this subsection without obtaining an applicable approval as prescribed.

55 Section 32 is amended

(a) in subsection (7) (c) by adding "section 32 and***" before "***Division***",***

(b) in subsection (7) by adding the following paragraph:

(c.01) the *Clean Energy Act*; ***,***

(c) in subsection (7) (x) by adding "44.1,***" after "***sections***", and***

(d) by repealing subsection (8).

56 Section 38 is amended by renumbering the section as section 38 (1) and by adding the following subsection:

(2) Without limiting subsection (1), the Lieutenant Governor in Council may make regulations

(a) prescribing powers for the purposes of section 12 (1),

(b) prescribing purposes of the authority for the purposes of section 12 (1.1), and

(c) for the purposes of section 12 (1.2), prescribing activities, classes of activities and approval requirements.

Transmission Corporation Act

57 The Transmission Corporation Act, S.B.C. 2003, c. 44, is repealed.

Utilities Commission Act

58 Section 1 of the Utilities Commission Act, R.S.B.C. 1996, c. 473, is amended by repealing the definitions of* "demand-side measure" *and

"government's energy objectives" ***and substituting the following:***

"British Columbia's energy objectives" has the same meaning as in section 1 (1) of the *Clean Energy Act*;

"demand-side measure" has the same meaning as in section 1 (1) of the *Clean Energy Act*; ***.***

59 Section 1 is amended by repealing the definition of **"transmission corporation"*.***

60 Section 3 (2) is amended by striking out "or***" at the end of paragraph (a) and by adding the following paragraph:***

(a.1) any provision of the *Clean Energy Act* or the regulations under that Act, or ***.***

61 Section 5 (0.1) and (4) to (9) is repealed.

62 Section 28 is amended

(a) in subsection (1) by striking out "90***" and substituting "***200***", and***

(b) by adding the following subsections:

(2.1) If required to do so by regulation, the commission, in accordance with the prescribed requirements, must set a rate for the authority respecting the service provided under subsection (1).

(2.2) A requirement prescribed for the purposes of subsection (2.1) applies despite

(a) any other provision of this Act or any regulation under this Act, except for a regulation under section 3, or

(b) any previous decision of the commission.

63 Section 29 is amended by striking out "90***" and substituting "***200***".***

64 Section 43 (1.1) is repealed.

65 Section 44.1 is amended

(a) by repealing subsections (1) and (4), and

(b) by repealing subsection (8) (a) and (b) and substituting the following:

(a) the applicable of British Columbia's energy objectives,

(b) the extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, ***.***

66 Section 44.2 is amended

(a) in subsection (3) by striking out "subject to subsections (5) and (6),***" and substituting "***subject to subsections (5), (5.1) and (6),***",***

(b) in subsection (5) by adding "filed by a public utility other than the authority***" after "***expenditure schedule***" and by repealing paragraphs (a) and (c) and substituting the following:***

(a) the applicable of British Columbia's energy objectives,

(c) the extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, , and

(c) by adding the following subsection:

(5.1) In considering whether to accept an expenditure schedule filed by the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*,

(c) the extent to which the schedule is consistent with the requirements under section 19 of the *Clean Energy Act*, and

(d) if the schedule includes expenditures on demand-side measures, the extent to which the demand-side measures are cost-effective within the meaning prescribed by regulation, if any.

67 Section 46 is amended

(a) in subsection (3) by striking out "Subject to subsections (3.1) and (3.2),***" and substituting "***Subject to subsections (3.1) to (3.3),***",***

(b) in subsection (3.1) by adding "applied for by a public utility other than the authority***" after "***under subsection (3)***" and by repealing paragraphs (a) and (c) and substituting the following:***

(a) the applicable of British Columbia's energy objectives,

(c) the extent to which the application for the certificate is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, ***, and***

(c) by adding the following subsection:

(3.3) In deciding whether to issue a certificate under subsection (3) to the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*, and

(c) the extent to which the application for the certificate is consistent with the requirements under section 19 of the *Clean Energy Act*.

68 Section 58.1 (2) (a) (ii) is amended by striking out "or 125.1 (4) (f)***".***

69 Part 3.1 is repealed.

70 Section 71 is amended

(a) in subsection (2.1) by adding "filed by a public utility other than the authority***" after "***whether an energy supply contract***" and by repealing paragraphs (a) and (c) and substituting the following:***

(a) the applicable of British Columbia's energy objectives,

(c) the extent to which the energy supply contract is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, ***,***

(b) by adding the following subsection:

(2.21) In determining under subsection (2) whether an energy supply contract filed by the authority is in the public interest, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*,

(c) the extent to which the energy supply contract is consistent with the requirements under section 19 of the *Clean Energy Act*,

(d) the quantity of the energy to be supplied under the contract,

(e) the availability of supplies of the energy referred to in paragraph (d),

(f) the price and availability of any other form of energy that could be used instead of the energy referred to in paragraph (d), and

(g) in the case only of an energy supply contract that is entered into by a public utility, the price of the energy referred to in paragraph (d). ***,***

(c) in subsection (2.5) by adding "with respect to a submission by a public utility other than the authority***" after "***under subsection (2.4)***" and by repealing paragraphs (a) and (c) and substituting the following:***

(a) the applicable of British Columbia's energy objectives,

(c) the extent to which the application for the proposed contract is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, and ***, and***

(d) by adding the following subsection:

(2.51) In considering the public interest under subsection (2.4) with respect to a submission by the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*, and

(c) the extent to which the application for the proposed contract is consistent with the requirements under section 19 of the *Clean Energy Act*.

71 Section 125 (2) is amended by adding the following paragraph:

(e) requiring the commission to set a rate for the purposes of section 28 (2.1) and prescribing requirements for the purposes of that section.

72 Section 125.1 is amended

(a) by repealing subsections (2), (3) and (4) (a), (c), (d), (f) and (j) to (n), and

(b) in subsection (4) (e) by adding "and***" at the end of subparagraph (ii), by striking out "***, and***" at the end of subparagraph (iii) and by repealing subparagraph (iv).***

73 Section 125.2 (3) is amended by striking out "transmission corporation***"***

and substituting "authority***".***

Wildfire Act

74 Section 7 of the Wildfire Act, S.B.C. 2004, c. 31, is amended

(a) by adding the following subsections:

(2.1) A person who is in a prescribed class of persons and who carries out an industrial activity or a prescribed activity on an area must, within the prescribed period and to the prescribed extent, abate a fire hazard on the area.

(2.2) A person referred to in subsection (2) is not required to abate a fire hazard on an area if a person referred to in subsection (2.1) is required to abate the fire hazard. ***, and***

(b) in subsection (3) by striking out "subsection (2)***" in both places and substituting*** "subsections (2) and (2.1)***" and by adding*** "applicable***" before*** "person***".***

75 Section 43 (3) is amended by striking out "section 7 (2) or (4),***" and substituting*** "section 7 (2), (2.1) or (4),***".***

76 Section 72 (2) (g) is repealed and the following substituted:

(g) respecting the abatement of fire hazards, including, without limitation,

(i) prescribing classes of person, activities and time periods for the purposes of section 7 (2.1), and

(ii) specifying, for the purposes of section 7 (2.1), the extent to which a fire hazard must be abated, .

Commencement

77 The provisions of this Act referred to in column 1 of the following table come into force as set out in column 2 of the table:

Item	Column 1 **Provisions of Act**	Column 2 **Commencement**
1	Anything not elsewhere covered by this table	The date of Royal Assent
2	Section 20	July 5, 2010
3	Section 42	July 5, 2010
4	Section 45	By regulation of the Lieutenant Governor in Council
		By regulation of the Lieutenant

5	Section 52	Governor in Council
6	Section 55 (d)	July 5, 2010
7	Section 57	July 5, 2010
8	Section 59	July 5, 2010
9	Section 73	July 5, 2010

Schedule 1

Heritage Assets

Those generation and storage assets commonly known as the following:

Aberfeldie

Alouette

Ash River

Bridge River

Buntzen/Coquitlam

Burrard Thermal

Cheakamus

Clowhom

Duncan

Elko

Falls River

Fort Nelson

G. M. Shrum

Hugh Keenleyside Dam (Arrow Reservoir)

John Hart

Jordan

Kootenay Canal

La Joie

Ladore

Mica, including units 1 to 6

Peace Canyon

Prince Rupert

Puntledge

Revelstoke, including units 1 to 6

Ruskin

Site C

Seton

Seven Mile

Shuswap

Spillimacheen

Stave Falls

Strathcona

Waneta

Wahleach

Walter Hardman

Whatshan

Schedule 2

Prohibited Projects

The projects of the authority, as set out in appendix F-8 of the authority's long-term acquisition plan, exhibit B-1-1, filed with the commission on June 12, 2008, are prohibited projects for the purposes of section 10, in particular, the following projects identified in appendix F-8:

(a) Murphy Creek;

(b) Border;

(c) High Site E;

(d) Low Site E;

(e) Elaho;

(f) McGregor Lower Canyon;

(g) Homathko River;

(h) Liard River;

(i) Iskut River;

(j) Cutoff Mountain;

(k) McGregor River Diversion.

Explanatory Note

This Bill sets out British Columbia's energy objectives, requires the British Columbia Hydro and Power Authority to submit an integrated resource plan describing what it plans to do in response to those objectives, and requires the authority to achieve electricity self-sufficiency by the year 2016. The Bill also prohibits certain projects from proceeding, ensures that the benefits of the heritage assets are preserved for British Columbians, provides for the establishment of energy efficiency measures and establishes the First Nations Clean Energy Business Fund. The Transmission Corporation and the authority are also to be unified under this Bill.

Appendix B-4

ENERGY PLAN 2002
ENERGY FOR OUR FUTURE: A PLAN FOR BC

(View Attachments Panel)

Note: in an effort to reduce unnecessary paper consumption
this appendix has been provided in electronic format ONLY
hardcopy production will be provided only upon request.

Renewable Fuels Notice – Carbon Tax

Carbon Tax Act

This notice provides important information on changes to legislation announced in the September Budget Update 2009, as a result of the coming into force of the renewable fuel standard (RFS) under the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act* on January 1, 2010. The RFS requires that the total volume of gasoline and diesel class fuels (i.e. light fuel oil) sold in the province contain an average of 5% renewable fuel (e.g. ethanol and renewable diesel fuel).

Effective January 1, 2010, ethanol and renewable diesel fuel are subject to tax under the *Carbon Tax Act*. Carbon tax will apply to ethanol at the same rate as gasoline, and to renewable biodiesel fuel at the same rate as light fuel oil. Renewable diesel fuel includes both biodiesel and hydrogenated-derived renewable diesel fuel.

The carbon tax rates for gasoline and light fuel oil will each be reduced by 5% in recognition of the RFS.

For information on carbon tax rates, please see ***Carbon Tax Rates by Fuel Type – to December 31, 2009*** and ***Carbon Tax Rates by Fuel Type - From January 1, 2010***.

Inventory Reporting Requirements

If you are a deputy collector or retail dealer and sell gasoline, light fuel oil, gas liquids or pentanes plus, you will be required to determine the amount of these fuels that you own, or are deemed to own, immediately after midnight on December 31, 2009. You must file an inventory return and pay the additional security due on that inventory to the ministry by January 15, 2010. If you do not own any of these fuels on January 1, 2010, you must still provide the ministry with an inventory return stating "nil" or "no inventory".

If you are required to provide an inventory under the C*arbon Tax Act* and, at the time you take your inventory, you have the capacity to store 1,000 litres of fuel, you will be provided an inventory allowance of $250.

Additional information regarding inventory reporting requirements and transitional rules for the purchase and use of fuel on, or after, January 1, 2010, is being prepared and will be available shortly.

Fixed Price Contracts

A refund is available to purchasers who entered into fixed price contracts before September 1, 2009, to purchase ethanol and renewable diesel fuel.

You are entitled to a refund of the carbon tax you pay on, or after, January 1, 2010, on ethanol or renewable diesel fuel if:

- you entered into a fixed price contract before September 1, 2009, to purchase the ethanol or renewable diesel,
- the ethanol or renewable diesel is delivered before July 1, 2010,
- the contract specifies the amount of ethanol or renewable diesel to be delivered under the contract,
- the amount of ethanol or renewable diesel delivered is at least 5% of the total fuel delivered under the contract, and
- you cannot recover the tax paid under the contract.

You are not entitled to a refund of the tax paid on any ethanol or renewable diesel you receive in excess of the amount specified in the contract.

For related information on renewable fuels and motor fuel tax, please see the ***Renewal Fuels Notice – Motor Fuel Tax.***

For information on other changes announced in the September Budget Update 2009, please see the notice, ***September Budget Update 2009 – Tax Change Summary***.

Reporting Tax on Sales Invoices

As a reminder, please note that, effective January 1, 2010, if you sell fuel:

- from a bulk storage facility, cardlock or terminal rack,
- for resale,
- to a registered consumer, or
- to a customer that requests an invoice,

you must provide an invoice to your customer showing:

- the date of the sale,
- your name and address,
- the name and address of the person you sold the fuel to,

- the quantity of each type of fuel sold, and
- the rates for motor fuel tax and carbon tax, for each type of fuel sold, as separate lines or columns on the invoice.

Further Information

If you have any questions, please call us at 604 660-4524 in Vancouver, or toll-free at 1 877 388-4440, or e-mail your questions to **CTBTaxQuestions@gov.bc.ca**

You can also find information on our website at **www.sbr.gov.bc.ca /business/Consumer_Taxes/Carbon_Tax/carbon_tax.htm**

Printer-friendly version

Backgrounder(s) & FactSheet(s): Backgrounder

NEWS RELEASE

For Immediate Release
2007OTP0139-001194
Sept. 26, 2007

Office of the Premier
Ministry of Community Services
Union of BC Municipalities

B.C. COMMUNITIES COMMIT TO CARBON NEUTRALITY BY 2012

VANCOUVER – Local governments from across B.C. signed a Climate Action Charter with the Province and the Union of BC Municipalities today, committing to a goal of becoming carbon neutral by 2012.

"Our government is committed to taking action on climate change and, by working in partnership with local governments, we will be more effective in reducing our greenhouse gas emissions," Premier Gordon Campbell said today, as he joined with UBCM president Brenda Binnie to sign a memorandum of understanding with the goal of local governments becoming carbon neutral over the next five years. "By signing the BC Climate Action Charter today, we are taking a key step toward improving the quality of life for our residents and communities tomorrow."

Sixty-two communities signed the Charter during Wednesday's UBCM session in Vancouver. In addition to a goal of becoming carbon neutral by 2012, local governments pledged to measure and report on their community's greenhouse gas emissions profile and work to create compact, more energy efficient communities. Regional district boards and municipal councils across the province have been considering adoption of the agreement's goals over the two weeks leading up to convention and it is expected more communities will sign on in the coming weeks.

"Local governments have provided a fast, positive response to the Premier's invitation to sign on to the BC Climate Action Charter," said Binnie. "The challenges posed by climate change require intergovernmental partnerships at all levels, so we anticipate many more signatories in the near future."

Carbon neutrality involves measuring the greenhouse gas emissions that come from government operations such as buildings and fleet vehicles and then reducing those emissions to net zero. Governments achieve carbon neutrality by reducing emissions where possible, by purchasing carbon offsets to compensate for its greenhouse gas emissions or by developing projects to offset emissions. Such projects may include converting to energy efficient buildings and replacing old fleet vehicles and buses with hybrids.

UBCM and the provincial government will establish a Joint Provincial-UBCM Green Communities committee and Green Communities Working Groups to define a range of actions that can affect climate change, build local government capacity to plan and implement climate change initiatives, support local governments in taking actions to make their own operations carbon neutral by 2012, and share information to support climate change activities.

To view a copy of the BC Climate Action Charter, visit www.cserv.gov.bc.ca/ministry/docs/climate_action_charter.pdf online.

-30-

1 backgrounder(s) attached.

Media contact:	Mike Morton Office of the Premier 250 213-8218	Anne McKinnon Ministry of Community Services 250 812-4012 (cell)
	Paul Taylor UBCM 250 356-2938	

For more information on government services or to subscribe to the Province's news feeds using RSS, visit the Province's website at www.gov.bc.ca.

BC Bioenergy Strategy

Growing Our Natural Energy Advantage

British Columbia
The Best Place on Earth

Table of Contents

Honourable Gordon Campbell
Premier of British Columbia

"The Province is addressing these challenges head on. The BC Bioenergy Strategy will help turn existing challenges into new opportunities – for both forestry and agriculture."

Human activity has changed our world. It has led to numerous advances – from instant power to airline travel to the farthest reaches of the globe. For a long time, these advances carried with them the unseen cost of rising greenhouse gas emissions, which has led to the monumental challenges of global warming and climate change.

The Province is addressing these challenges head on. The BC Bioenergy Strategy will help turn existing challenges into new opportunities – for both forestry and agriculture.

The BC Bioenergy Strategy sets us on a path to diversify rural economies and turn adversity into opportunity by recovering maximum value from all our forests and creating new economic opportunities for mountain pine beetle damaged timber through conversion into bioenergy.

Bioenergy provides new opportunities for agriculture. It will be developed from B.C.'s landfills, crop residues and agricultural wastes.

Bioenergy is a positive, practical approach that will involve all regions and all British Columbians in preparing for a low-carbon future. The bioenergy we generate from our abundant resources in B.C. can help meet greenhouse gas reduction targets at home and in other jurisdictions, creating enduring economic benefits.

This strategy builds upon a solid foundation of expertise, innovation and experience. Many B.C. forest companies already convert wood residues into electricity and heat used in their mills, and some supply surplus amounts into the power grid. Established community energy projects and landfill methane-capture systems demonstrate the success and commitment to bioenergy that exists in B.C. right now.

With the support of government, industry and partners in the Western Climate Initiative, this strategy will help launch British Columbia as a carbon-neutral energy powerhouse in North America.

The BC Bioenergy Strategy will help B.C. achieve its targets for zero net greenhouse gas emissions from energy generation, improved air quality, electricity self-sufficiency and increased use of biofuels.

Bioenergy holds the promise of innovation, investment and job creation. All are within our grasp if we're willing to look to the future and embrace the changes that are upon us.

Honourable Gordon Campbell
Premier of British Columbia

Honourable Richard Neufeld
Minister of Energy, Mines and Petroleum Resources

Honourable Rich Coleman
Minister of Forests and Range

Honourable Pat Bell
Minister of Agriculture and Lands

Honourable Richard Neufeld
Minister of Energy, Mines and Petroleum Resources

Honourable Rich Coleman
Minister of Forests and Range

Honourable Pat Bell
Minister of Agriculture and Lands

HIGHLIGHTS

CLEANER, GREENER

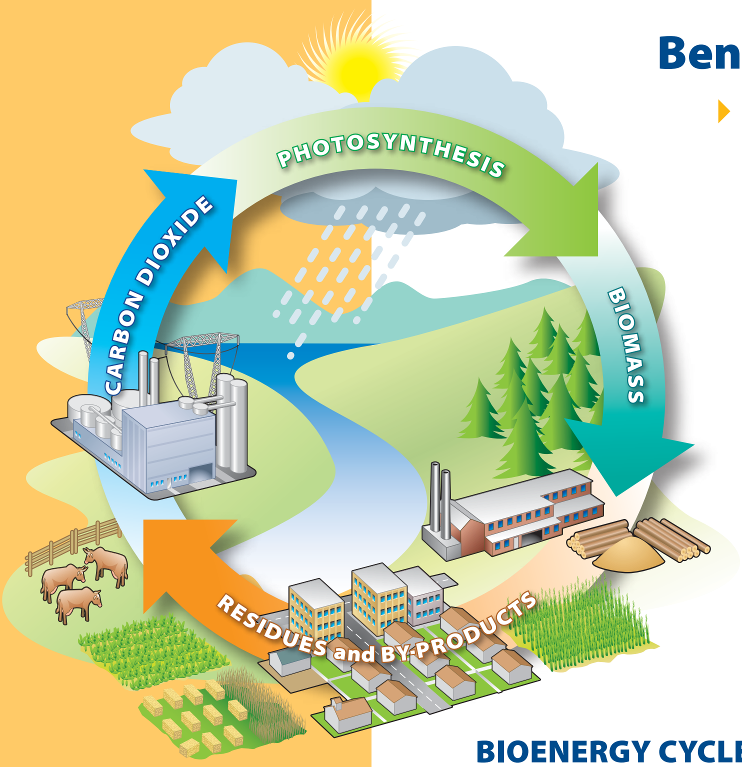
Bioenergy is energy derived from organic biomass sources – such as trees, agricultural crops, food processing and agricultural wastes and manure. Biomass can be generated from logging, agriculture and aquaculture, vegetation clearing and forest fire hazard areas. When used for energy, biomass such as organic waste, wood residues and agricultural fibre is considered clean or carbon neutral because it releases no more carbon into the atmosphere than it absorbed during its lifetime. When used to replace non-renewable sources of energy, bioenergy reduces the amount of greenhouse gases released into the atmosphere.

The BC Bioenergy Strategy will help British Columbia and other places in North America reduce greenhouse gas emissions and strengthen our long-term competitiveness and electricity self-sufficiency. Bioenergy is absolutely critical to achieving B.C.'s climate goals and economic objectives. It turns the challenges of the mountain pine beetle infestation into new opportunities and looks to future bioenergy technologies. This strategy directly supports the commitments made in the BC Energy Plan and is a key contributor to helping our partners in the Western Climate Initiative achieve their emission reduction goals.

Building Opportunities for Rural British Columbia

British Columbia's bioenergy assets include top researchers, innovative companies, committed partners, forward-thinking communities, and half of the entire country's biomass electricity-generating capacity.

- Establish $25 million in funding for a provincial Bioenergy Network for greater investment and innovation in B.C. bioenergy projects and technologies.
- Establish funding to advance provincial biodiesel production with up to $10 million over three years.
- Issue a two-part Bioenergy Call for Power, focusing on existing biomass inventory in the forest industry.



BIOENERGY CYCLE

Benefits for British Columbians

- We will aim for B.C. biofuel production to meet 50 per cent or more of the province's renewable fuel requirements by 2020, which supports the reduction of greenhouse gas emissions from transportation.
- We will develop at least 10 community energy projects that convert local biomass into energy by 2020.
- We will establish one of Canada's most comprehensive provincial biomass inventories that creates waste to energy opportunities.

Developing Our Bioenergy Resources

British Columbia is world-renowned for its plentiful natural resources and strong environmental values. Through the BC Bioenergy Strategy, British Columbia will take its proven track record one step further. We will develop the province's bioenergy resources to enhance both the environmental and economic benefits for the people who live here. Next steps include:

- Collaborate with the Western Climate Initiative and the Pacific NorthWest Economic Region.
- Create First Nations bioenergy opportunities.
- Require methane capture from our largest landfills.
- Utilize waste wood from phased-out beehive burners to produce clean energy.
- Provide energy providers with information to develop new opportunities.
- Support wood gasification research, development and commercialization.

WHAT IS BIOMASS?

Biomass is renewable organic matter like crops, trees, wood chips, aquatic plants, manure and municipal waste. British Columbians produce biomass from daily activities. Biomass can take the form of organic garbage, yard and garden waste, sewage, and wood from demolition and construction sites.

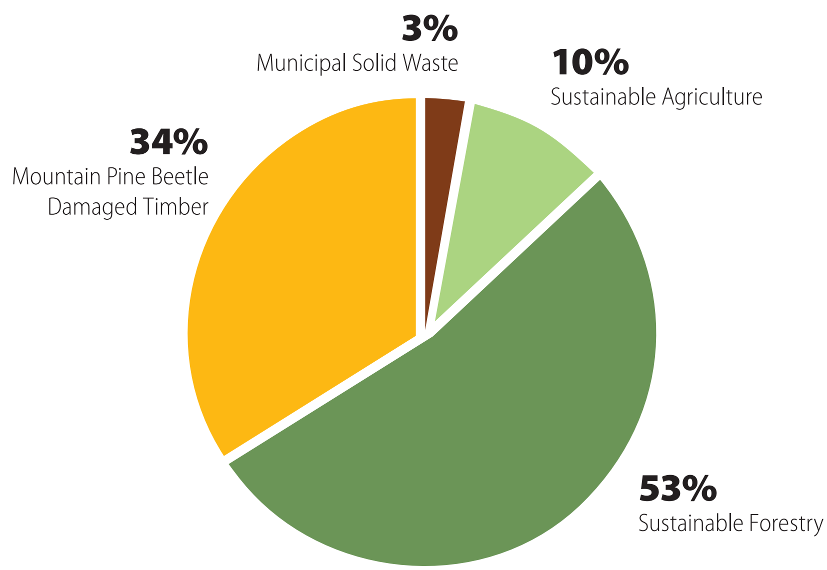
The province's main sources of biomass come from forest and agricultural activities. Food processing, aquaculture and other industries also produce large amounts of biomass.

Biomass can be used to produce heat and electricity, liquid and gaseous fuels (such as ethanol from grain and cellulose, biodiesel from oilseed and waste greases and biogas from anaerobic digestion), solid fuels (pellets and briquettes), and various other products.

British Columbia has 50 per cent of the biomass electricity-generating capacity of the entire country within our province.

B.C.'s Biomass Resources

British Columbia is committed to developing our abundant natural resources in an environmentally responsible manner. Through the implementation of the BC Bioenergy Strategy, Government will create new economic opportunities for forestry, agriculture, municipalities and First Nations communities. It will establish British Columbia as the hub of a global supply network of bioenergy resources, technologies and services.



Sustainable Forestry
This includes forest residues from logging practices, road clearing and other forestry activities. Site preparation, early tree removal and tree stand establishment could increase forest residues and be a source of biomass.

Mountain Pine Beetle Damaged Timber
The increased annual allowable cut to remove beetle-killed timber and non-recoverable pine are temporary sources of biomass, which will be available for approximately 20 years.

Sustainable Agriculture
Crop residues that are not utilized, which could include stalks, husks, straw and other post-harvest fibre, are available as a biomass source. Crops grown for biodiesel and ethanol production may include grain and canola. In future, livestock manure and dedicated crop growth are potential agricultural sources for biomass.

Municipal Solid Waste
Municipal landfills contain biomass that can become a source of fuel through landfill gas collection or direct combustion.

Canada has approximately seven per cent of the world's land mass, and 10 per cent of its forests. Unused biomass from Canada's forestry and farming operations that is not otherwise required for soil health or ecosystem restoration could provide as much as 27 per cent of our national energy needs.

Biomass Supply Estimates

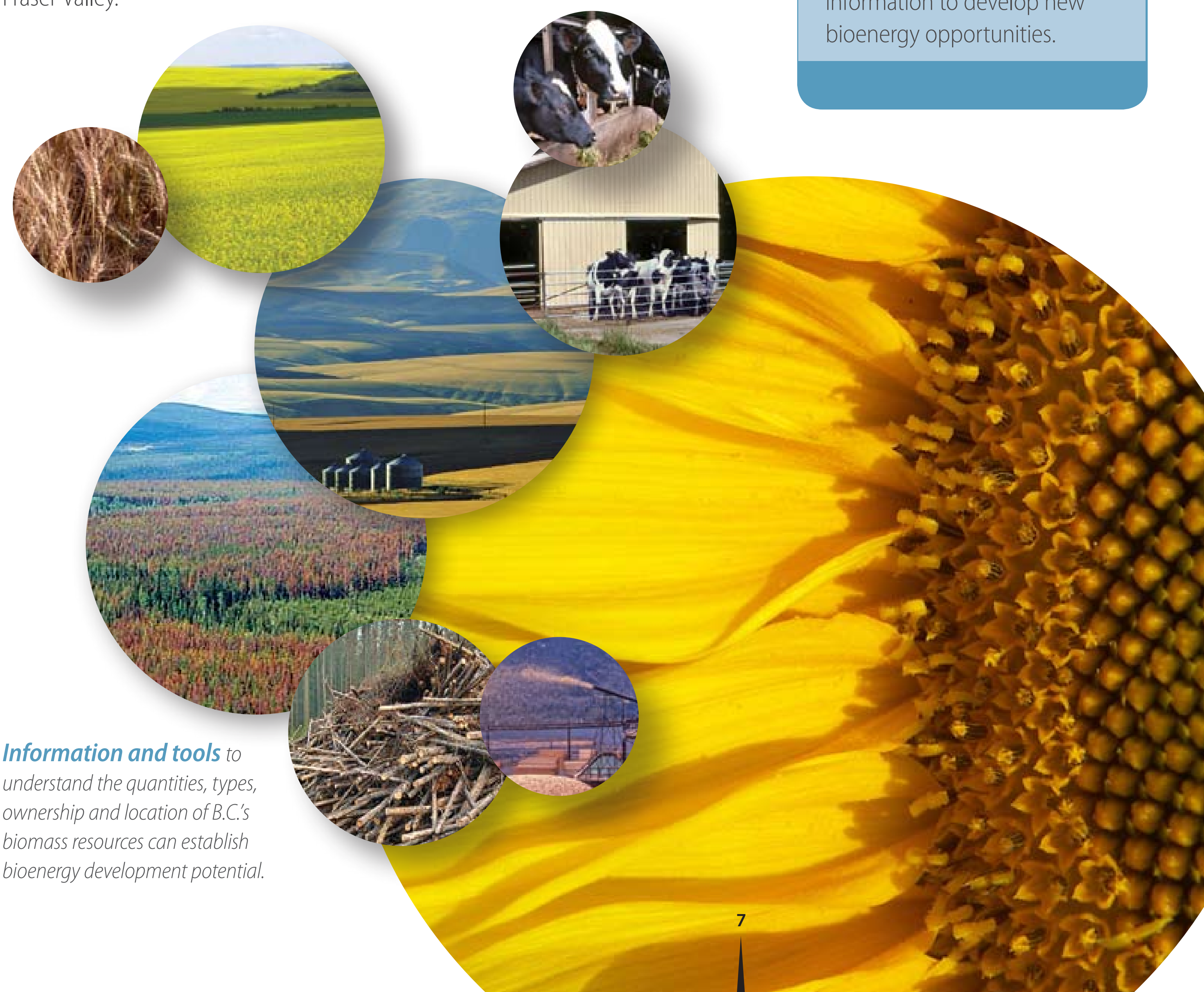
The Ministry of Forests and Range has begun work on wood Biofuel Supply Estimates. These supply estimates, highlight the bioenergy potential of different regions and can assist independent power producers and other energy developers in evaluating bioenergy opportunities from wood.

The Ministry of Agriculture and Lands is also developing an inventory mapping system to chart the volume, availability and geographic distribution of agricultural and agri-food by-products, starting with the Fraser Valley.

NEXT STEPS

A comprehensive inventory of the province's biomass resources will:

- Total the approximate volume of biomass available.
- Consolidate information and make it available in a user-friendly, easily accessed, online format.
- Provide energy producers with information to develop new bioenergy opportunities.



Information and tools *to understand the quantities, types, ownership and location of B.C.'s biomass resources can establish bioenergy development potential.*

BIOENERGY CALL FOR POWER

BC Hydro will issue a two-part Bioenergy Call for Power early in 2008. This call will follow up on the March 2007 Request for Expressions of Interest for power production to convert underutilized wood into electricity.

The Bioenergy Call for Power will provide communities that are dependent on forestry and agriculture with new opportunities to partner with industry, First Nations and government to maximize economic benefits and improve air quality.

For further information visit **www.bchydro.com/2007/bioenergy**

BIODIESEL PRODUCTION

The Province will provide up to $10 million in funding over three years to encourage the development of biodiesel production in B.C. This will help diversify rural economies, improve competitiveness for B.C. biodiesel producers and provide new clean energy opportunities.

Government and its partners will collaborate to develop B.C. bioenergy projects utilizing energy from wood waste, agriculture, renewable fuels and municipal waste.

Energy from Wood Waste

The opportunities to use both wood waste and mountain pine beetle damaged timber are endless. The City of Revelstoke is a leader in bioenergy. Wood waste from a local sawmill fuels a biomass boiler that enables the municipality to recover heat in the form of low pressure steam for drying lumber at the sawmill and providing hot water to a community energy system for buildings in the downtown core. The Revelstoke community energy project, in operation since 2005, increases energy efficiency, reduces wood waste from sawmills and improves local air quality.

Energy from Agriculture

Bioenergy presents exciting economic prospects for B.C.'s agriculture sector. The development of biofuels from grains, oilseeds, waste fats and greases may better exploit unused crop residues and agricultural by-products. At the same time, bioenergy has the potential to address animal manure and other waste management challenges.

As technology advances, biofuels will be produced from an even broader range of sources, such as algae, straw and plants that thrive in less fertile regions. These opportunities will help balance the development of bioenergy from agriculture with global food requirements.

The Fraser Valley, North Okanagan, Cariboo, Northeast B.C. and Northwest B.C. have an abundance of livestock facilities which could produce a continuous supply of feedstock for anaerobic digestion. Anaerobic digestion uses bacteria to convert organic waste into a biogas composed primarily of methane and carbon dioxide.

Government is funding an Anaerobic Digestion Feasibility Study to explore long-term bioenergy opportunities in rural regions throughout B.C.

Energy from Renewable Fuels

Government has set out to establish a low carbon fuel standard for British Columbia and is committed to implementing a five per cent average renewable fuel standard for diesel and to increasing the ethanol content of gasoline to five per cent by 2010. Farmers in the Peace Region stand to benefit from rising demand for grain used in ethanol production. A study completed in April 2007 for the B.C. Grain Producers Association shows potential for a 22-million-litre-per-year biodiesel production facility in the area using 56,000 tonnes of canola.

Energy from Municipal Waste

Turning municipal waste into green energy offers endless potential. The Hartland Landfill near Victoria captures landfill gases through a series of underground pipes. The gas is collected, then cooled, compressed and transported to a generating facility where it creates enough electricity for about 1,400 homes.

A similar system at Vancouver's Delta landfill can generate up to 50 gigawatt hours of power and provides heat to local greenhouses. The SEEGEN project, owned by the Greater Vancouver Regional District, incinerates waste to produce up to 125 gigawatt hours of power and low pressure steam for use in a nearby paper recycling plant.

NEXT STEPS

- The Province will develop legislation to phase in requirements for methane capture at landfills, the source of about nine per cent of B.C.'s greenhouse gas emissions. This methane could be used for clean energy.
- The Province will collaborate to streamline the regulatory and permitting environment and address the current waste management challenge posed by agricultural residues such as animal manure.
- The Province will develop regulatory measures to eliminate beehive burners, which will help divert those wood residues to higher value, lower pollutant bioenergy production.
- The Province will promote wood pellet production and facilitate market development opportunities within the province and around the world.
- The Province will improve access to wood fibre feedstocks for the generation of heat and power in collaboration with the forest and energy industries, utilities and provincial government partners.
- The Province will review the *Safety Standards Act* Power Engineers, Boiler, Pressure Vessel and Refrigeration Safety Regulation to accelerate adoption of bioenergy technology in the forest industry.
- The Province will work with the bioenergy industry and others to develop new fine particulate standards for industrial boilers to improve air quality.

BIOFLEET is an initiative to expand the development and use of biodiesel in Western Canada. This project will continue to build market confidence in biodiesel to increase the purchase and use of clean, renewable fuel and will also reduce greenhouse gas emissions generated by vehicle fleets. British Columbia will consume more than 500 million litres of biofuel annually by 2010.

BC BIOENERGY NETWORK

To support B.C.'s clean energy goals, capture value from beetle damaged timber and help rural agriculture and forest communities diversify and remain competitive, Government will establish funding for a $25 million Bioenergy Network. It will set the course to reduce greenhouse gas emissions, while increasing home-grown renewable energy production and strengthening the forest and agriculture industries.

This commitment will build on the existing foundation of bioenergy production sites, research centres and technology development projects, leading the way to greater investment in innovation and affirming B.C.'s role as a world leader and global partner for sustainable bioenergy solutions.

British Columbia has a strong bioenergy and biorefining network of academic and industry talent, as well as a number of active projects.

Building on the Existing Bioenergy and Biorefining Network

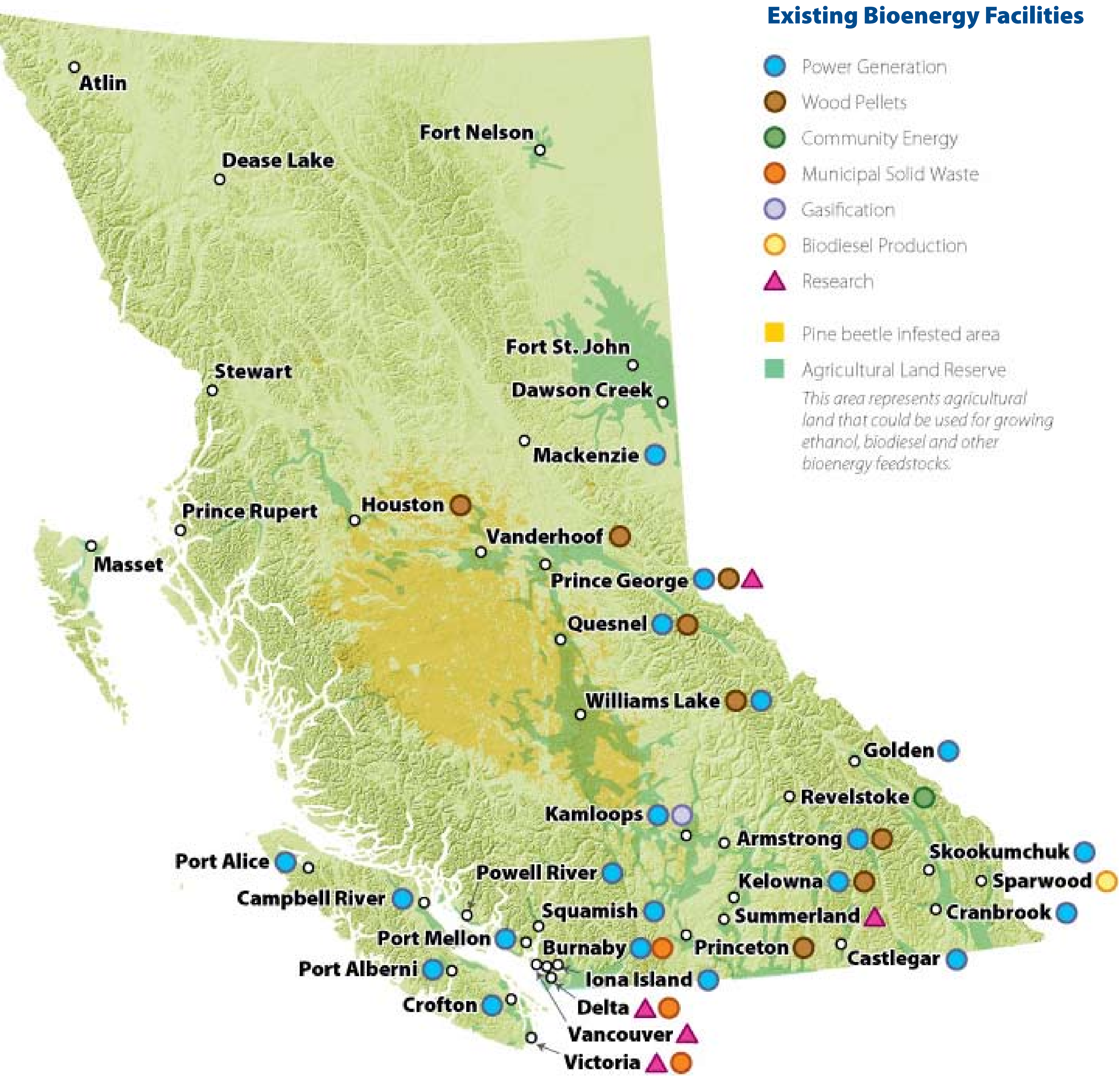
The purpose of the Network is to achieve greenhouse gas emission reductions, improve air quality and capitalize on B.C.'s bioenergy potential through the development of projects which could include:

- New bioenergy technology and production capacity to better utilize beetle damaged timber and other woodwaste in sawmills and pulp mills.
- Agricultural biogas production from animal and food processing wastes.
- Next-generation biofuels such as ethanol from woodwaste and biodiesel from algae.
- Projects to convert municipal waste and landfill gas to electricity and other fuels.

The Network strengthens the development of world-class bioenergy research and technology expertise in British Columbia. This will include the creation of at least one academic leadership chair in bioenergy.

British Columbia's current bioenergy network already includes:

- Over 800 megawatts of biomass electricity capacity is installed in British Columbia, primarily within the forest sector – enough for 640,000 households.
- The British Columbia wood pellet industry enjoys a 16 per cent share of the growing European Union market for bioenergy feedstock. In 2007, British Columbia produced over 900,000 tonnes of wood pellets, of which 90 per cent was exported for thermal power production overseas.
- British Columbia's pulp and paper mills meet over 33 per cent of their electricity needs through cogeneration of electricity and steam on site.


Existing Bioenergy Facilities
Power Generation
Wood Pellets
Community Energy
Municipal Solid Waste
Gasification
Biodiesel Production
Research
Pine beetle infested area
Agricultural Land Reserve
This area represents agricultural land that could be used for growing ethanol, biodiesel and other bioenergy feedstocks.
Atlin
Fort Nelson
Dease Lake
Fort St. John
Stewart
Dawson Creek
Mackenzie
Houston
Prince Rupert
Vanderhoof
Masset
Prince George
Quesnel
Williams Lake
Golden
Revelstoke
Kamloops
Armstrong
Skookumchuk
Port Alice
Powell River
Kelowna
Sparwood
Campbell River
Squamish
Summerland
Cranbrook
Port Mellon
Burnaby
Princeton
Castlegar
Port Alberni
Iona Island
Crofton
Delta
Vancouver
Victoria

Building Bioenergy Capacity

When it comes to using renewable fuels, British Columbians are among the most receptive consumers, and the demand for biodiesel and ethanol is growing. Municipalities including Vancouver, Richmond, Whistler, Delta, Burnaby and North Vancouver are using biodiesel in their fleet vehicles, and so are BC Transit and other commercial fleets. There is significant potential to expand the production and use of biofuels in the Peace River Region and other areas of the province. Community energy projects increase energy self-sufficiency, address waste management issues, diversify local industries and create new jobs. Projects underway include:

- Highlighting biomass and bioproduct development potential in Quesnel through an inventory of available wood fibre.
- A biomass energy system to heat schools in Nakusp.
- An engineering assessment and business model for a biomass heat-and-power community energy system in Port Hardy.
- A biomass gasification community energy project at Dockside Green in Victoria.

British Columbia is expanding its bioenergy capacity through government funding for bioenergy programs, including:

- Up to $10 million in funding over three years for biodiesel production.
- A biodiesel production feasibility study to encourage the development of oilseed crushing and biodiesel facilities in the Peace Region.
- A feasibility study conducted by the BC BioProducts Association on building an anaerobic digestion and gas processing facility in the Fraser Valley.
- The Anaerobic Digester Calculator Project, an electronic tool to assess the environmental benefit and economic viability of constructing anaerobic digestion facilities in specific locations.

Ethanol BC, a program to support value-added uses for wood residue, has funded:

- Research and development of softwood residue-to-ethanol technology by Lignol Innovations.
- Advances in wood gasification technology by Nexterra.
- Fuel pellet design, engineering and emission performance assessments testing wood, agricultural fibre and other feedstocks.

The Province is promoting a Product Commercialization Roadmap that will enhance the export success of British Columbia's bioproducts by guiding companies through business planning, financial analysis and processes for product and market development.

NEXT STEPS

The Province will establish the Bioenergy Network to:

- Support wood gasification research, development and commercialization in collaboration with the University of Northern British Columbia, University of British Columbia, Forest Products Innovation, the National Research Council, the forestry and energy sectors, industry and other partners.
- Advance biorefining for multiple, value-added product streams, such as biochemicals, in conjunction with bioenergy production in new facilities and/or at existing industrial operations by working with the BC Bioproducts Association, First Nations, agricultural and forest sectors.
- Encourage the development of pilot and demonstration projects with industries and communities in key biomass resource areas.
- Support research into socially and environmentally responsible dedicated energy crop production and enhance enzymatic and other biotechnology solutions for biomass-to-energy conversion.
- Advance the development of biofuels, such as cellulosic ethanol and renewable diesel from algae and other resources, through the Green Energy and Environmentally Friendly Chemical Technologies Project and other initiatives.

WITHIN OUR POWER

British Columbia has an abundance of underutilized wood in the form of sawmill residues and logging debris, and a growing supply of timber killed by the mountain pine beetle.

British Columbia currently leads the nation in wood energy production and consumption. However, it is estimated that about 1.2 million bone-dry tonnes of mill residues per year – an amount that could produce approximately 1,900 gigawatt hours of electricity – are incinerated in beehive burners in the province with no energy recovery and impacts on air quality. These resources and wood residues in other regions present an opportunity for bioenergy in British Columbia.

WOOD PELLETS are produced from wood residue collected from sawmills and wood product manufacturers. Heat and pressure are used to turn wood residue into pellets without chemical additives, binders or glue.

4 | BUILD BIOENERGY PARTNERSHIPS

CROSS-GOVERNMENT COLLABORATION

The Province will work with federal agencies such as Sustainable Development Technology Canada, Natural Resources Canada, and the Western Diversification Office to:

- Promote bioenergy research and project development, support the efficient use of biomass, address current waste challenges and diversify community economies.
- Streamline and coordinate the development of bioenergy policies and programs to advance the Province's goals for energy, the economy and the environment.

B.C. is viewed around the world as a bioenergy hot spot, and its increasing profile in the global economy highlights the importance of strong relationships with other jurisdictions with shared interests in bioenergy development.

Nationally and internationally, many view British Columbia as the hub of a growing bioenergy and biorefining network. The Western Climate Initiative allows B.C. to foster economic opportunities through the development of new technologies and innovation. B.C. and western states have engaged in electricity trading for the past 30 years, and the Government has signed a joint statement with Sweden that strengthens a partnership of information exchange and best practices for the development and use of bioenergy and biorefining technologies. The BC Bioenergy Strategy affirms B.C.'s commitment in an agreement with Manitoba to reduce greenhouse gas emissions by broadening renewable energy portfolios to include biomass power.

The expertise gained through the BC Bioenergy Strategy offers other jurisdictions the potential to benefit, while creating new economic opportunities for British Columbians. With our plentiful biomass resources, industry and academic leadership, and the Government commitment to bioenergy, British Columbia will continue to:

- Develop, deploy and export British Columbia's clean and alternative energy technologies.
- Maximize bioenergy market opportunities.
- Advance bioenergy research, collaborate in project development and build upon shared interests with other jurisdictions in Canada and around the world.

NEXT STEPS

- The Province will advance joint interests and share information on best practices in bioenergy research and development with the Western Climate Initiative and the Pacific NorthWest Economic Region.
- Under the British Columbia/Alberta Memorandum of Understanding on Energy Research, Technology Development and Innovation, the Government will develop a joint framework for bioenergy research, technology demonstration and deployment.
- The Province will create First Nations bioenergy opportunities and invite representatives to speak about biomass community energy systems.
- The Province will release an information guide on pursuing biomass energy opportunities and technologies in British Columbia for First Nations, small communities, local government and industry.

CONCLUSION

With our strengths in bioenergy, British Columbia will pursue our alternative energy advantage. Bioenergy is critical in meeting that objective. The know-how, researchers and partner communities here today are committed to making this happen. The enhanced BC Bioenergy Network, funding to advance biodiesel production and the two-part Bioenergy Call for Power, will take B.C. the next step in realizing our full natural resource potential.

The BC Bioenergy Strategy will benefit communities by helping make cleaner, greener energy available for use in our homes and vehicles. It will benefit our economy by tapping into the potential of B.C.'s biomass resources, unleashing the energy of materials that previously went to waste and promoting the development of new industries and markets. In turn, it will benefit our environment by helping meet our growing energy demands with clean, renewable and environmentally responsible energy resources.

BIOENERGY TECHNOLOGY DEVELOPMENT TIMELINE

NOW

TECHNOLOGIES IN USE IN B.C.

WOOD TO ELECTRICITY BY COMBUSTION AND STEAM TURBINES

Technology available–economics drive the decision

WOOD TO SOLID FUEL PELLETS

Technology available–economics drive the decision

WOOD TO SYNGAS FOR WOOD DRIERS

Recently implemented in B.C.–driven by high natural gas prices

WOOD TO SYNGAS FOR PULP MILL LIME KILNS

Further research and development required to maintain clean syngas stream

2010 - 2015

TECHNOLOGIES EXPECTED TO BE IN USE

BIOMASS TO CLEAN SYNGAS TO POWER INTERNAL COMBUSTION ENGINE FOR UP TO 10MW ELECTRICITY GENERATION

To be piloted–high probability of success

BIOMASS TO HIGH GRADE SYNGAS FOR LIQUID FUEL PRODUCTION

Needs research and development, large-scale pilots and further research and development on catalysts to adapt current technology for coal conversion

WOOD TO CLEAN SYNGAS TO POWER TURBINE FOR ELECTRICITY GENERATION

Needs pilot trials and research and development

** SYNGAS is synthetic gas produced through the thermal gasification of biomass.*

TECHNOLOGIES EXPECTED TO BE IN USE

CELLULOSE TO ETHANOL

Needs large-scale pilots and further research and development on enzymes

AGRICULTURAL WASTE/ MANURE TO POWER

Technology available– economics drive the decision

ENERGY CROPS LIKE GRAIN AND OILSEEDS TO RENEWABLE FUELS

Technology available– economics drive the decision

ANAEROBIC DIGESTION AND ALGAE FARMING FOR BIO-OIL

Needs pilot scale trials and research and development

2015 - 2020

BIOREFINING: BIOMASS TO ENERGY, BIOCHEMICALS AND OTHER PRODUCTS

Needs extensive research and development

Four key drivers spurred the development of the BC Bioenergy Strategy:

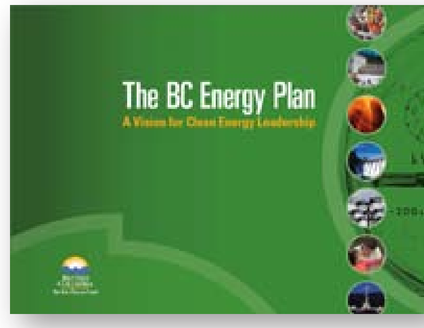
1 **Environment** – bioenergy can lower greenhouse gas and other air emissions and encourage the shutdown of beehive burners, organic garbage conversion, methane capture from landfills and better agricultural waste management.

2 **Mountain Pine Beetle Infestation** – bioenergy can help capture value from a deteriorating resource and help the forest sector, as well as impacted communities, remain competitive.

3 **Electricity Self-sufficiency** – bioenergy can help B.C. meet its future energy demands and become energy self-sufficient with made-in-B.C. energy resources from the forest and agricultural sectors.

4 **Long-term Competitiveness** – bioenergy can create new bioeconomic opportunities for forestry, agriculture, municipalities and First Nation communities and establish British Columbia as a global supplier of bioenergy resources, technologies and services.

The BC Bioenergy Strategy supports these BC Energy Plan Policy Actions:



- Ensure self-sufficiency to meet electricity needs, including "insurance" by 2016.
- Establish a standing offer for clean electricity projects up to 10 megawatts.
- All new electricity generation projects will have zero net greenhouse gas emissions.
- Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.
- Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.
- Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.
- Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.
- Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.
- Establish the Innovative Clean Energy Fund to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.
- Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.
- Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.
- Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.
- Support the federal action of increasing the ethanol content of gasoline to five per cent by 2010 and adopt quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions.
- Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.
- Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.

For more information on the BC Bioenergy Strategy contact:

Ministry of Energy, Mines and Petroleum Resources
1810 Blanshard Street
PO Box 9318 Stn Prov Govt
Victoria, BC V8W 9N3
Tel: 250.952.0156

www.energyplan.gov.bc.ca/bioenergy

BRITISH COLUMBIA
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Appendix C

SECONDARY RESEARCH REPORTS

NREL National Renewable Energy Laboratory
Innovation for Our Energy Future
A national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy

Green Power Marketing in the United States: A Status Report (2008 Data)

Lori Bird, Claire Kreycik, and Barry Friedman

Technical Report
NREL/TP-6A2-46581
September 2009

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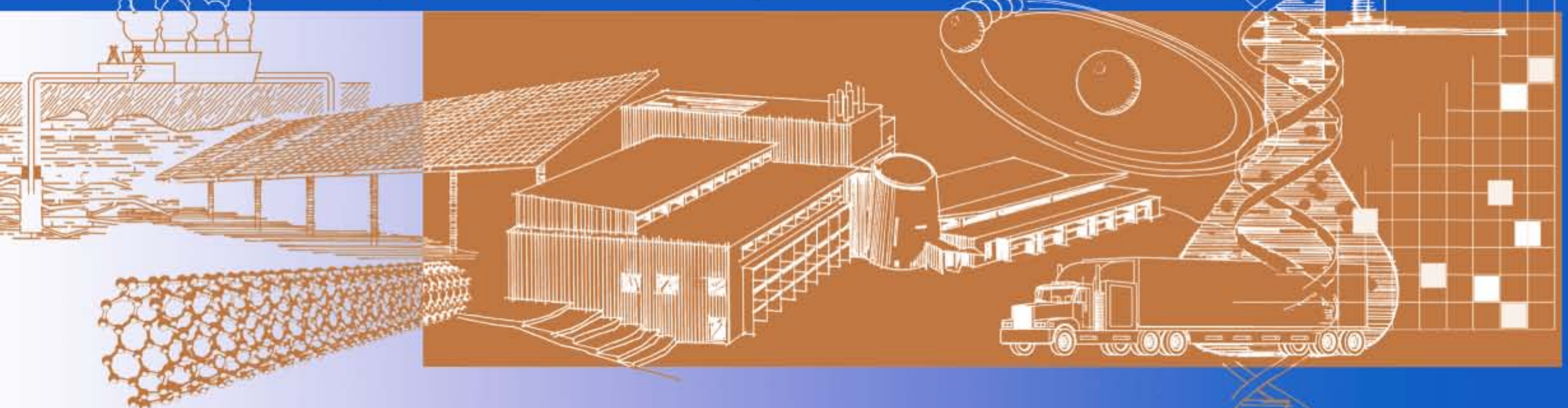

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Prepared under Task No. SAO9.3004

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List of Acronyms

aMW	average megawatt
DOE	Department of Energy
EEPS	energy efficiency portfolio standards
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ESC	energy savings certificate
FCA	fuel-cost adjustment
kWh	kilowatt-hour
M&V	measurement and verification
MW	megawatt
MWh	megawatt-hour
NREL	National Renewable Energy Laboratory
NYSERDA	New York State Energy Research and Development Authority
OG&E	Oklahoma Gas & Electric
PG&E	Pacific Gas & Electric
REC	renewable energy certificate
RGGI	Regional Greenhouse Gas Initiative
RPS	renewable portfolio standard
TRC	tradable renewable certificates

Table of Contents

List of Figures

List of Tables

Introduction

Voluntary consumer decisions to buy electricity supplied from renewable energy sources represent a powerful market support mechanism for renewable energy development. In the early 1990s, a small number of U.S. utilities began offering "green power" options to their customers.[1] Since then, these products have become more prevalent, both from traditional utilities and from renewable energy marketers operating in states that have introduced competition into their retail electricity markets or offering renewable energy certificates (RECs) online. Today, more than half of all U.S. electricity customers have an option to purchase some type of green power product directly from a retail electricity provider, while all consumers have the option to purchase RECs.

More than 850 utilities, or about 25% of utilities nationally, offer green power programs to customers. These programs allow customers to purchase some portion of their power supply as renewable energy—almost always at a higher price—or to contribute funds for the utility to invest in renewable energy development. The term "green pricing" is typically used to refer to these utility programs offered in regulated or noncompetitive electricity markets.

In states with competitive (or restructured) retail electricity markets, electricity customers can often buy electricity generated from renewable sources by switching to an alternative electricity supplier that offers green power. In some of these states, default utility electricity suppliers offer green power options to their customers in conjunction with competitive green power marketers.[2] Nearly a dozen states that have opened their markets to retail competition have experienced some green power marketing activity.

Finally, regardless of whether they have access to a green power product from their retail power provider, any consumer can purchase green power through renewable energy certificates (RECs), which represent the "environmental attributes" of electricity generated from renewable energy-based projects. Consumers can also support renewable energy development through REC purchases without having to switch to an alternative electricity supplier. Today, several dozen companies actively market RECs to residential or business customers throughout the United States. Many REC marketers also sell greenhouse gas emissions offsets sourced from renewable energy projects.

This report documents green power marketing activities and trends in the United States. First, we present aggregate green power sales data for all voluntary purchase markets across the United States. The next three sections provide summary data on 1) utility green pricing programs offered in regulated electricity markets; 2) green power marketing activity in competitive electricity markets, as well as green power sold to voluntary purchasers in the form of RECs; and 3) renewable energy sold as greenhouse gas offsets in the United States. These sections are

[1] The term "green power" generally refers to electricity supplied in whole or in part from renewable energy sources, such as wind and solar power, geothermal, hydropower (typically low-impact or small hydro), and various forms of biomass.
[2] Under these programs, consumers can buy renewable energy from independent renewable energy marketing companies without switching their electricity service from the default or standard-offer service provider.

followed by a discussion of key market trends and issues. The final section offers conclusions and observations. The data presented in this report are based on figures provided to NREL by utilities and independent renewable energy marketers.[3]

[3] Green power market data for previous years are available in Bird et al. (2008), Bird et al. (2007), Bird and Swezey (2006), Bird and Swezey (2005a), Bird and Swezey (2004), Bird and Swezey (2003), Swezey and Bird (2000), and Swezey and Bird (1999).

Green Power Market Summary and Trends

Green Power Sales

Overall, retail sales of renewable energy in voluntary purchase markets exceeded 24 billion kilowatt-hours (kWh) in 2008, or about 0.6% of total U.S. electricity sales.[4] This includes sales of renewable energy derived from both "new" and "existing" renewable energy sources, consistent with the generally accepted market definition,[5] with most sales supplied from new sources. In 2008, renewable energy sources supplied about 85% of renewable energy sold into voluntary purchase markets.[6] In addition, greenhouse gas offsets sourced from new renewable energy resources–totaling nearly 250,000 tons of CO_2 equivalent–were sold to U.S. voluntary purchasers in 2008.

Wind energy represented 71% of total green power sales; followed by biomass energy sources, including landfill gas (17%); hydropower (primarily low impact or small hydro) (9%); geothermal (2%); solar (<1%); and unknown sources (1%) (Figure 1). Based on the sales data presented in this report, we estimate the market value of green power sales in 2008 to be between $110 million and $190 million.

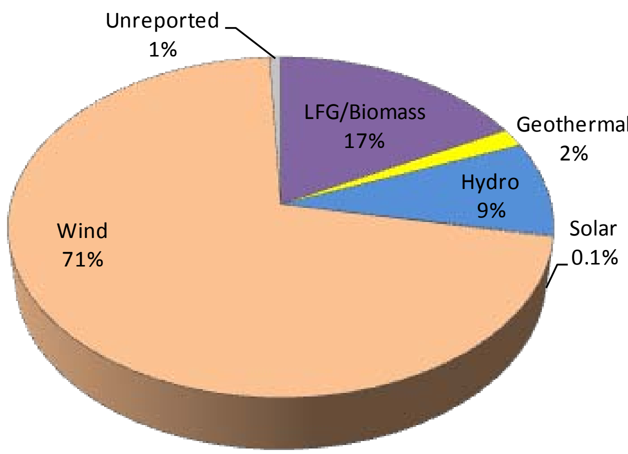


Figure 1. Estimated green power sales by renewable energy source, 2008

[4] U.S. electricity sales totaled 3,765 billion kWh in 2007 (2008 data are not yet available), according to the U.S. Energy Information Administration (EIA). See http://www.eia.doe.gov/cneaf/electricity/epa/epat7p2.html. The remaining renewable energy generation is rate-based by utilities or used to meet renewable portfolio standards.
[5] With green power, a distinction is often made based on the vintage of the renewable energy generator. The green power industry generally follows the *Green-e Energy* National Standard, which defines a "new" renewable generation facility as one placed in operation or repowered on or after January 1, 1997. Therefore, an "existing" generation facility is one placed in service before January 1, 1997. For more information on the *Green-e Energy* National Standard, see http://www.green-e.org/getcert_re_stan.shtml.
[6] Estimates presented in this report are primarily based on data provided by utilities and marketers and supplemented with other available data. Because we are unable to obtain data from all market participants, the estimates presented here likely underestimate the size of the entire market.

Green power sales (in kilowatt-hours) increased by 34% in 2008, with annual average growth of 41% since 2004 (Table 1). REC sales have been driving much of the growth, increasing 47% in 2008. Overall, REC markets represent nearly two-thirds of industry sales.[7] Sales in competitive markets and green pricing program grew moderately in 2008; green pricing sales were dampened by the termination of one of the largest programs (Florida Power and Light Sunshine Energy Program).[8]

Sales to nonresidential customers continued to outpace those to residential consumers, with more than three-quarters of all sales by volume to the nonresidential sector in 2008 (Table 2). Nearly all REC sales were to business and institutional customers, while residential customers played a larger role in green pricing programs and competitive markets, where they accounted for more than 50% of renewable energy sales (Table 3).

Table 1. Estimated Annual Green Power Sales by Market Sector, 2005-2008*
(Millions of kWh)

Market Sector	2005	2006	2007	2008	% Change 2004/2005	% Change 2005/2006	% Change 2006/2007	% Change 2007/2008
Utility Green Pricing	2,500	3,400	4,300	4,800	33%	39%	25%	12%
Competitive Markets	2,200	1,700**	3,200	3,900	-19%	-20%**	88%**	22%
REC Markets***	3,900	6,800	10,600	15,600	126%	75%	55%	47%
Retail Total	**8,500**	**11,900**	**18,100**	**24,300**	**37%**	**41%**	**53%**	**34%**

*Includes sales of new and existing renewable energy. Totals and growth rates may not calculate due to rounding.
**2006 sales figures may be underestimated because of data gaps.
***Includes only RECs sold to end-use customers separate from electricity.

Table 2. Estimated Annual Green Power Sales by Customer Segment, 2005-2008*
(Millions of kWh)

Customer Segment	2005	2006	2007	2008	% Change 2005/2006	% Change 2006/2007	% Change 2007/2008
Residential	3,000	3,200	4,500	5,500	8%	39%	22%
Nonresidential	5,500	8,700	13,600	18,800	58%	56%	38%
Total	**8,500**	**11,900**	**18,100**	**24,300**	**41%**	**53%**	**34%**
% Nonresidential	65%	73%	75%	77%	--	--	--

*Totals and growth rates may not compute due to rounding.

[7] The REC sales figures reflect sales to end-use customers separate from electricity. RECs bundled with electricity and sold to end-use customers through utility green pricing programs or in competitive electricity markets are counted in these other categories.

[8] The Florida Public Service Commission (PSC) initially acted to discontinue the program as a result of concerns over the amount of program revenues spent on marketing compared to expenditures on the renewable energy resources used to supply the program, as well as its support for out-of-state resources. However, the final basis for the decision to terminate the program, after a subsequent program audit, was related to the commission's assessment that a voluntary program was not needed after the Florida Legislature mandated an RPS. By Order No. PSC-08-0600-PAA-EI, issued September 16, 2008, in Docket No. 070626-EI, the commission terminated the program. http://www.floridapsc.com/library/filings/08/08720-08/08-0600.ord.doc

At the end of 2008, kilowatt-hour sales of renewable energy in voluntary markets represented a generating capacity equivalent of about 7,300 MW, with about 6,300 MW of that from "new" renewable energy sources (Table 4).[9] Since 2000, the amount of renewable energy capacity serving green power markets has increased more than 40-fold (see Appendix A).

Table 3. Estimated Annual Green Power Sales by Customer Segment and Market Sector, 2008 (Millions of kWh)

Customer Segment	Green Pricing	Competitive Markets	REC Markets	Total
Residential	2,600	2,700	200	5,500
Nonresidential	2,100	1,200	15,400	18,700
Total	**4,700**	**3,900**	**15,600**	**24,300**
% Residential	55%	69%	1%	23%

Note: Totals may not add due to rounding.

Table 4. Estimated Cumulative Renewable Energy Capacity Supplying Green Power Markets, 2005-2008 (Megawatts)

Market	2005 Total Renewables Capacity	2005 *New* Renewables Capacity	2006 Total Renewables Capacity	2006 "New" Renewables Capacity	2007 Total Renewables Capacity	2007 "New" Renewables Capacity	2008 Total Renewables Capacity	2008 *New" Renewables Capacity
Utility Green Pricing	800	700	1,100	1,000	1,400	1,300	1,500	1,400
Competitive Markets/RECs	1,700	1,300	2,400	2,100	3,700	3,000	5,800	4,900
Total	**2500**	**2000**	**3,500**	**3,100**	**5,100**	**4,300**	**7,300**	**6,300**

Note: "New" renewables capacity is a subset of total renewables capacity supplying green power markets.

Customer Participation

Based on our estimates, nearly one million electricity customers nationwide purchased green power products in 2008 through regulated utility companies, from green power marketers in a competitive-market setting, or in the form of RECs (Table 5).[10] Utility green pricing programs have shown continued customer growth as the number of utility programs has increased and as existing programs have grown; however, in 2008, customer numbers did not grow in aggregate. This is largely due to the cancellation of the Florida Power and Light (FPL) Sunshine Energy Program, a large program with more than 35,000 participants prior to its termination.

Competitive-market green power participation has expanded during the past few years but has been less consistent over time, as some markets have grown and then contracted (such as in

[9] Capacity estimates are calculated based on reported green power kilowatt-hours sales assuming capacity factors for each renewable resource type. For wind, a capacity factor of 33% was assumed, 90% for landfill gas, 80% for biomass, 96% for geothermal, 40% for hydroelectric, and 15% for solar electric.

[10] It is important to note that there is greater uncertainty in our customer estimates for competitive and REC markets because of data limitations. For more detailed estimates by state for 2006 and 2007, see data from U.S. EIA 2008 in Appendix C. Generally, our estimates are consistent with the EIA estimates when adjusted for customers in Ohio, who participated in community aggregations in 2005 and earlier. We excluded these customers from our estimates because they purchase products with very low renewable energy content (1% to 2%).

California and Pennsylvania). The most recent growth in competitive markets has been concentrated in Texas and northeastern states. In 2008, the number of customers buying RECs increased from more than 10,000 to about 30,000, but it still represents a small fraction of the total green power market on a customer basis (but not a kilowatt-hour basis). Despite the limited number of residential customers purchasing RECs, REC sales represent nearly two-thirds of all green power kilowatt-hour sales and have grown dramatically in recent years as a result of several very large purchases (see Appendix B for a list of top green power purchasers).

Table 5. Estimated Cumulative Green Power Customers by Market Segment, 2002-2008

	2002	2003	2004	2005	2006	2007	2008
Utility Green Pricing	230,000	270,000	330,000	390,000	490,000	550,000	550,000
Competitive Markets	~150,000	>170,000	>140,000	>180,000	~210,000	300,000	390,000
REC Markets*	< 10,000	< 10,000	< 10,000	< 10,000	~10,000	>10,000	30,000
Retail Total	**~390,000**	**~450,000**	**~480,000**	**~580,000**	**~710,000**	**~860,000**	**~970,000**
% Change	**~39%**	**~15%**	**~7%**	**~21%**	**~22%**	**~21%**	**13%**

Note: In some cases, estimates have been revised from those reported in previous NREL reports as updated data have become available. Totals may not add due to rounding.
*Includes only end-use customers purchasing RECs separate from electricity.

Average participation rates among utility green pricing programs increased slightly from 2.0% to 2.2% in 2008, with a median value of 1.2%; top performing programs have achieved rates ranging from 5% to 21%. Competitive markets have experienced green power customer penetration rates ranging from 1% to 2% in the states with the most active markets; however, participation in competitive markets has been subject to market conditions and rules, and has been more volatile than in traditionally regulated markets.

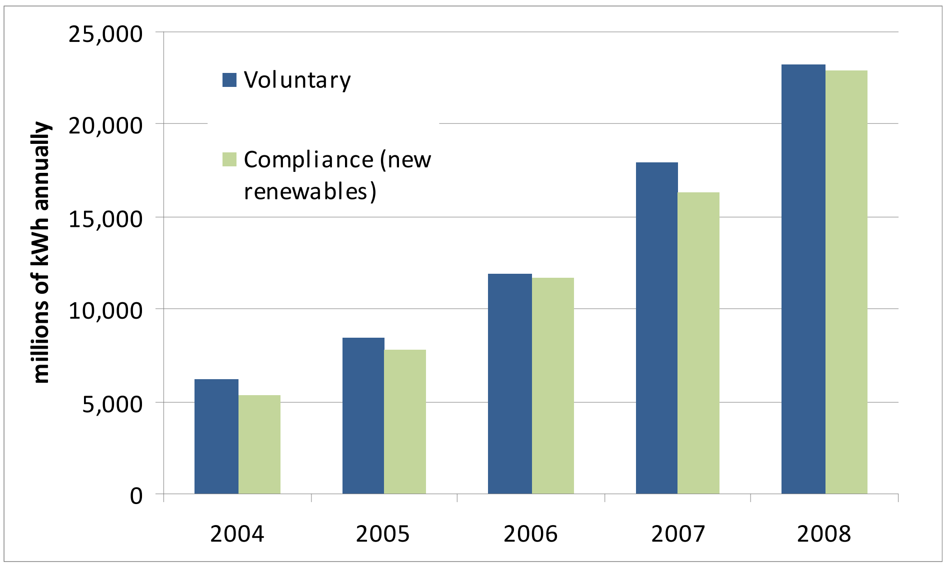
Comparison of Voluntary and Compliance Markets

In 29 states and the District of Columbia, renewable portfolio standard (RPS) policies require that utilities or load-serving entities include a certain percentage of renewable energy within their power generation mix; the percentages required and eligibility requirements vary among the states. Eligible renewable energy may either be purchased by load-serving entities to meet their RPS requirements, or may be bought by consumers or businesses wanting to buy renewable energy on a voluntary basis. However, green power certification programs and state RPS policy rules generally ensure that there is no double counting between the two markets (i.e., that the same kilowatt-hour is not used for more than one purpose).[11] Ensuring the absence of double-counting is important to the integrity of the market in that consumers who pay a premium for green power want to support renewable energy that would not have been otherwise supported through regulatory requirements.

In 2008, state RPS policies collectively called for utilities to procure about 23 billion kWh of "new" renewable energy generation (Barbose 2009), compared to about 24 billion kWh sold into

[11] For additional detail on the treatment of voluntary green power purchases in state RPS policies, see Holt and Wiser 2007.

the voluntary green power market.[12] Figure 2 shows that between 2004 and 2008, voluntary market demand for renewables slightly exceeded compliance market demand for new renewables. However, renewable energy demand to meet RPS policies is expected to grow rapidly in coming years. By 2010, RPS policies collectively call for utilities to obtain more than 60 billion kWh of new renewables, increasing to about 100 billion kWh in 2012; voluntary market growth rates would have to increase to keep pace.[13]



Note: Compliance market data sourced from Lawrence Berkeley National Laboratory (LBNL) (Barbose 2009)

Figure 2. Comparison of voluntary and compliance markets for renewable energy, 2004-2008

[12] Although RPS policies generally allow pre-existing renewable energy generation sources (i.e., those installed prior to the adoption of the RPS) to meet their targets, the estimates presented here reflect only the amount of new renewable energy generation that these policies are expected to stimulate. These figures are compared to the voluntary market estimates, because voluntary markets primarily support generation from new renewable energy projects (i.e., those installed after voluntary green power markets were established). Estimates of compliance market demand assume that RPS targets are fully met.

[13] This figure does not include the Kansas RPS because the Kansas Corporation Commission has not yet developed the methodology for calculating utility's peak demand, so the amount of renewable generation required to meet the RPS is not yet known.

Utility Green Pricing

This section provides information specific to utility green pricing programs, a subset of the market. The number of utilities offering green pricing has grown steadily in recent years—today, more than 850 investor-owned, public, and cooperative utilities in most states offer green pricing programs. Appendix D provides a list of utilities offering green pricing, and Appendix E provides Web links to all green power product offerings.[14] Because a number of small municipal or cooperative utilities offer programs developed by their power suppliers, the number of distinct green pricing programs is about 160. Some states have adopted laws requiring utilities to offer consumers green power options, which have driven the development of new programs in some states.[15]

Green Pricing Products and Premiums

Typically, green pricing programs are structured so that customers can either purchase green power for a certain percentage of their electricity use (often called "percent-of-use products") or in discrete amounts or blocks at a fixed price ("block products"), such as a 100 kWh block. Most utilities offer block products but may also allow customers to buy green power for their entire monthly electricity use. Utilities that offer percent-of-use products generally allow residential customers to elect to purchase 25%, 50%, or 100% of their electricity use as renewable energy, while a few offer fractions as small as 10%. Under these types of programs, larger purchasers, such as businesses, can often purchase green power for some fraction of their electricity use as well.

In 2008, the price of green power for residential customers in utility programs ranged from -1.0¢/kWh (a savings compared to standard service) to 8.8¢/kWh above standard electricity rates, with an average premium of 1.8¢/kWh and median of 1.5¢/kWh. These premiums have been adjusted to account for any fuel-cost exemptions granted to green power program participants.[16] In 2008, the utility programs with the lowest premiums for energy derived from new renewable sources had premiums ranging from -1.0¢/kWh (a savings) to 0.9¢/kWh. On average, consumers spend about $5.40 per month above standard electricity rates for green power through utility programs, which is consistent with previous years.

Since 2000, the average price premium has dropped at an average annual rate of 8% (Table 6; Figure 3). Some of this reduction can be attributed to lower market costs for renewable energy supplies, although changes in market conditions since mid-2008 have made these trends less clear. In recent years, increases in the price of natural gas narrowed the price gap between renewables and gas-fired generation alternatives, leading to lower initial premiums for many new programs; however, since the economic downturn in mid- to late-2008, natural gas prices have fallen dramatically, reversing this trend. Although wind was generally competitive with wholesale power prices in 2008, a drop in these prices may pose additional challenges for its

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[14] For an up-to-date list of utilities with green pricing programs, see the U.S. Department of Energy's Green Power Network Web site at http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=1.

[15] These states include Colorado, Iowa, Minnesota, Montana, New Mexico, Oregon, Vermont, and Washington.

[16] For example, some utilities exempt green pricing customers from monthly or periodic fuel charges imposed to pay higher than expected fossil-fuel costs. For a more detailed discussion of this topic, see Bird et al. (2008).

competitiveness in 2009 (Wiser and Bolinger 2009). The competitiveness of wind and other renewables with conventional generation, as well as regional demand from state renewable energy standards (and national demand if a federal standard is adopted), will affect premiums in coming years.

Table 6. Residential Price Premiums of Utility Green Power Products (¢/kWh), 2001-2008

	2001	2002	2003	2004	2005	2006	2007*	2008*
Average Premium	2.93	2.82	2.62	2.45	2.36	2.12	1.85	1.8
Median Premium	2.5	2.5	2	2	2	1.78	1.5	1.5
Range of Premiums	0.9-17.6	0.7-17.6	0.6-17.6	0.33 - 17.6	(0.7)-17.6	(0.1)-17.6	0.09-7.5	(-1.0)-8.8
10 Programs with Lowest Premiums**	1.0-1.5	0.7-1.5	0.6-1.3	0.33-1.0	(0.7)- 0.9	(0.1)-1.0	0.09-0.8	(-1.0)-0.9
Number of Programs Represented	60	80	91	101	104	97	71	86

*In later years, calculations of premiums were based on programs that responded to the questionnaire. In previous years, a larger sample of programs was used to calculate the premium, as data were available.

**Represents the 10 utility programs with the lowest price premiums for new customer-driven renewable energy. This includes only programs that have installed—or announced firm plans to install or purchase power from—new renewable energy sources. In 2001 the discrepancy between the low end of the range for all programs and the Top 10 programs results from the program with the lowest premium (0.9¢/kWh) not being eligible for the Top 10 because it was either selling some existing renewables or had not installed any new renewable capacity for its program.

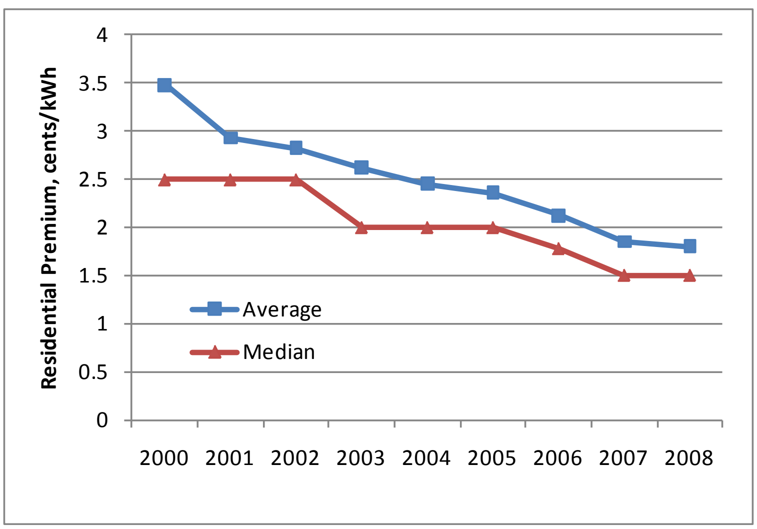

Figure 3. Trends in utility green pricing premiums, 2000-2008

Green Pricing Customer Participation

At the end of 2008, about 550,000 customers were participating in utility green pricing programs in regulated electricity markets (Table 7).[17] As in the past, a relatively small number of green power programs account for the majority of customers, with just 10 programs accounting for almost 70% of all participants (Appendix F)**.**[18] From 2001 to 2007, the number of customer participants increased more than threefold, but this trend reversed in 2008. With the cancellation of the large FPL program, nearly 40,000 customers left the market, and total participants in utility programs nationwide fell slightly. Without the loss of the FPL program, the number of participants in utility green power programs would have grown modestly, by about 6%.[19]

The decline in the economy, particularly in the second half of 2008, likely contributed to smaller gains in participants relative to previous years and a number of programs reported losses in the total number of participants. Perhaps surprisingly, nonresidential participant growth was on par with 2007; while the reason for this increase is unclear, one possible explanation could be heightened interest in renewable energy issues in an election year in which renewables and climate change were a focus. It is also possible that some programs placed greater emphasis on attracting commercial customers to make up for residential customer losses, as a number of programs that reported losing residential customers, reported overall gains in sales as a result of increased nonresidential sales.

Table 7. Estimated Cumulative Number of Customers Participating in Utility Green Pricing Programs (Regulated Electricity Markets Only)

Customer Segment	2001	2002	2003	2004	2005	2006	2007	2008
Residential	166,300	224,500	258,700	323,700	383,400	470,800	526,700	519,700
Nonresidential	2,500	3,900	6,500	8,100	11,300	15,500	20,200	26,100
Total	**168,800**	**228,400**	**265,200**	**331,800**	**394,700**	**486,300**	**546,900**	**545,800**
% Total Annual Growth	**27%**	**35%**	**16%**	**25%**	**19%**	**23%**	**12%**	**0%**
% Residential Growth	27%	35%	15%	25%	18%	23%	12%	-1%
% Nonresidential Growth	47%	56%	67%	25%	40%	37%	30%	29%

Table 7 delineates residential and nonresidential customer participation in utility green pricing programs over time. The vast majority of participants are residential customers, with

[17] NREL obtained consumer response data for about two-thirds of utility green pricing programs in 2008, including all of the major programs. The remaining programs, which are smaller in size, do not have a large impact on overall participant numbers. Wherever possible, other sources and previously reported data were used to estimate data gaps.

[18] NREL issues five different Top 10 lists based on total sales of renewable energy to program participants, total number of customer participants, customer participation rates, green power sales as a fraction of total utility sales, and the premium charged to support new renewables development. These lists can be found at http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=3.

[19] The Florida Public Service Commission (PSC) initially acted to discontinue the program as a result of concerns over the amount of program revenues spent on marketing compared to expenditures on the renewable energy resources used to supply the program, as well as its support for out-of-state resources. However, the final basis for the decision to terminate the program, after a subsequent program audit, was related to the commission's assessment that a voluntary program was not needed after the Florida Legislature mandated an RPS. By Order No. PSC-08-0600-PAA-EI, issued September 16, 2008, in Docket No. 070626-EI, the commission terminated the program. http://www.floridapsc.com/library/filings/08/08720-08/08-0600.ord.doc

nonresidential customers accounting for only 5% of all participants. However, nonresidential participation is growing at a faster rate than residential participation, which is having a significant positive impact on overall sales volume because of the larger size of nonresidential purchases.

At the end of 2008, the average participation rate in utility green pricing programs among eligible utility customers was 2.2%, with a median of 1.2% (Table 8). These industry-wide rates have shown little change in recent years. The overall lack of improvement in participation rates results from a number of factors, including a customer unwillingness to pay a premium for green power, and varied levels of interest among utilities in marketing and promoting the program (Holt and Holt 2004, Swezey and Bird 2001). However, the top-performing programs continue to show improvement, with participation rates ranging from about 5% to 21% in 2008, compared to a range of 3% to 6% in 2002. The 20% participation threshold was exceeded for the first time in 2007.

Table 8. Customer Participation Rates in Utility Green Pricing Programs, 2002-2008

Participation Rate	2002	2003	2004	2005	2006	2007	2008
Average	1.2%	1.2%	1.3%	1.5%	1.8%	2.0%	2.2%
Median	0.8%	0.9%	1.0%	1.0%	1.0%	1.3%	1.2%
Top 10 Programs	3.0% - 5.8%	3.9% - 11.1%	3.8% - 14.5%	4.6% - 13.6%	5.1% - 16.9%	5.2%- 20.4%	5.0% - 21.0%

In 2008, utilities reported that an average of 5.5% and a median of 2.5% of customers dropped out of green pricing programs. Retention rates are still relatively high despite the fact that electricity and energy prices remained high in most regions of the country throughout most of the year. This finding suggests that customers tend to be "sticky" and maintain participation in green power programs, despite electricity and other energy cost increases. While data on the reason for dropouts is not available, anecdotal evidence from some utilities suggests that customer moves can be a significant source of dropouts. Most utilities (about 70%) do not impose minimum periods for which customers must subscribe to the green power program. If a minimum term is imposed, it is most commonly one year—although there are several programs that offer fixed-price green power for contracts of longer durations.

Green Pricing Renewable Energy Sales

Utility green pricing sales continue to exhibit some growth, but growth has slowed in the past two years, in particular. Collectively, utilities in regulated electricity markets sold about 4.8 billion kWh of green power to customers in 2008 (Table 9). Green pricing program sales to all customer classes grew by 11% in 2008, compared to rates ranging from 26% to 56% in recent years (Table 9 and Figure 4). The loss of the FPL program had a noticeable impact on sales. Without the termination of the FPL program, utility green pricing program sales would have grown at a rate of 22% in 2008, similar to growth in 2007.

Sales growth is mostly attributed to increases in the number of nonresidential customers and larger purchases; in 2008, the average nonresidential purchase nearly doubled from the 2007 average (Table 10). Although the reason for these increased purchases is not known, it could be attributed to declines in green power prices for nonresidential retail customers, or enrollment of larger commercial and industrial customers. As noted earlier, some programs may have also placed greater emphasis on marketing to the commercial sector to make up for residential customer losses.

Table 9. Annual Sales of Renewable Energy through Utility Green Pricing Programs (Regulated Electricity Markets Only), Millions of kWh, 2002-2008

	2002	2003	2004	2005	2006	2007	2008
Sales to Residential	660	870	1,300	1,610	2,100	2,550	2,660
Sales to Nonresidential	230	410	540	840	1,300	1,630	2,150
Total Sales to All customers	**900**	**1,280**	**1,840**	**2,450**	**3,400**	**4,290**	**4,810**
% Annual Growth in Total	**56%**	**43%**	**43%**	**33%**	**39%**	**26%**	**12%**
% Nonresidential of Total Sales	26%	32%	30%	34%	38%	38%	32%

Note: Totals may not add due to rounding.

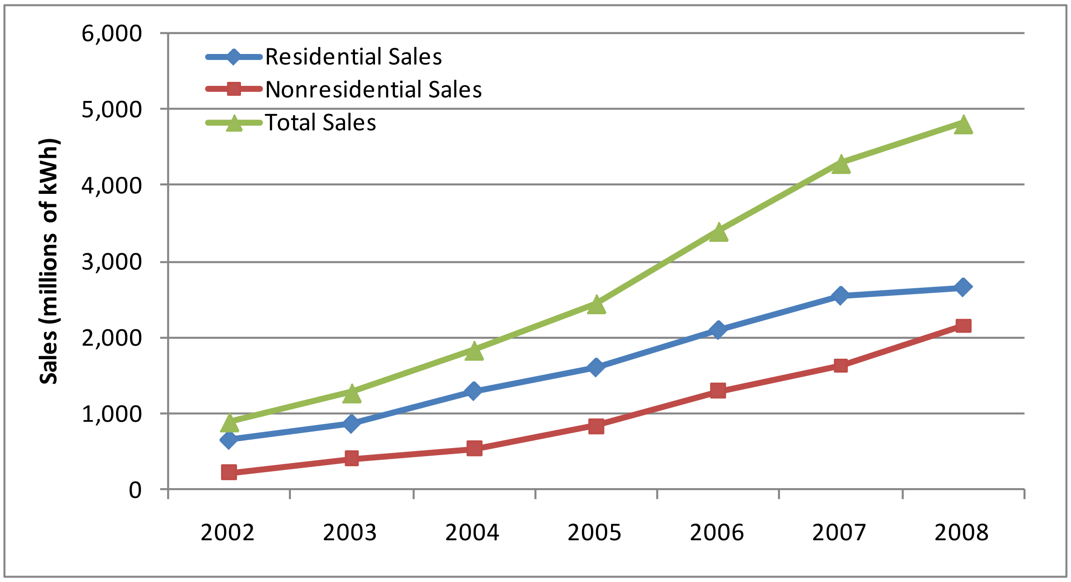

Figure 4. Annual sales of renewable energy through utility green pricing programs, 2002-2008 (regulated electricity markets only)

Table 10. Average Purchases of Renewable Energy per Customer (kWh per Year), 2002-2008

	2002	2003	2004	2005	2006	2007	2008
Residential Customers	2,900	3,400	4,000	4,200	4,400	4,900	5,500
Nonresidential Customers	60,000	63,100	67,200	74,500	85,700	77,400	141,300
All Customers	3,900	4,800	5,500	6,200	6,700	7,400	20,800

About 95% of the renewable energy sold to consumers through green pricing programs was supplied from projects meeting the generally accepted industry definition of "new." Renewable energy sold through green pricing programs in 2008 represents an equivalent renewable energy capacity of more than 1,500 MW, with more than 1,400 MW of this represented by "new" renewable energy resources (Table 11).[20] Wind, solar, landfill gas, and other biomass are the renewable resources most commonly included in utility programs; although solar, in particular, may be used to supply a small fraction of kilowatt-hour sales. Wind energy represents the largest portion of the total capacity. In 2007, sales of renewable energy through green pricing programs represented more than 1,400 MW of renewable energy capacity, with about 1,300 MW of that from new renewable energy sources. Table 4 and Appendix A present estimates of new capacity serving green pricing programs in earlier years.

Table 11. Renewable Energy Generation and Capacity Supplying Green Pricing Programs, 2008

	Landfill Gas	Other Biomass	Geo-thermal	Hydro	Solar	Wind	Unknown	Total
Sales MWh	343,000	202,000	75,000	52,000	9,000	3,993,000	143,000	4,817,000
% of Total Sales	7%	4%	2%	1%	0.2%	83%	3%	100%
Total MW	44	29	9	15	7	1,381	33	1,517
MW New RE	41	28	9	14	7	1,341	-	1,440

In 2008, green power sales represented a small but increasing proportion of a utility company's overall energy sales. Table 12 shows that, on average, renewable energy sold through green pricing programs in 2008 represented approximately 1% of total utility electricity sales (on a kWh basis), while a few utilities reported fractions as high as about 5% to 6% of total retail electricity sales. On a residential basis, green power sales represented a higher fraction of total utility electricity sales, with one utility reporting a fraction as high as 23%.

Table 12. Renewable Energy Sales as a Percent of Utility Electricity Sales, 2007-2008

	2007			2008		
Customer Class	**Avg.**	**Med.**	**Range**	**Avg.**	**Med.**	**Range**
Residential	1.4%	0.6%	0% - 17.4%	1.5%	0.5%	0% - 23.4%
Nonresidential	0.5%	0.2%	0% - 6.3%	0.8%	0.2%	0% - 12.0%
All customers	0.8%	0.3%	0% - 5.7%	1.0%	0.4%	0% - 6.4%

[20] Capacity estimates are calculated based on reported green power kilowatt-hours sales assuming capacity factors for each renewable resource type. For wind, a capacity factor of 33% was assumed, 90% for landfill gas, 80% for biomass, 96% for geothermal, 40% for hydroelectric, and 15% for solar electric. Estimates of megawatts in previous years' projections were higher on a relative basis due to the capacity factor assumed for wind. In prior years a 30% capacity factor was assumed, but in 2008 estimates of MW were based on a 33% capacity factor to reflect improvements in capacity factors as a result of the movement toward larger turbines as well as greater reliance on projects in areas with strong wind resources. For every million MWh, this accounts for a discrepancy of 35 MW of capacity in the estimates.

Competitive Green Power and REC Markets

This section provides greater detail on green power sold in competitive (or restructured) electricity markets as well as in the form of RECs—subsets of the entire green power market. About one-quarter of U.S. states have restructured their electricity markets for retail service competition. Currently, electricity consumers in the following states can purchase competitively marketed green power: Connecticut, Illinois, Maine, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, Rhode Island, Texas, and the District of Columbia.[21,22] Competitively marketed green power offerings are also available to nonresidential consumers in a few other states.

Initially, buying green power in competitive retail markets entailed switching electricity service from the incumbent utility to a green power supplier. However, with few exceptions, green power marketers have found it difficult to compete or to persuade customers to switch suppliers. As a remedy, a number of states now require default suppliers (which are often the incumbent distribution utilities) to offer green power options to their customers. These load-serving entities typically provide customers with underlying electricity generation, combined with a choice of several green products offered by competing green power marketers. In addition, several utility suppliers have voluntarily teamed with a single green power marketer to offer a green power option to their customers. Such programs are now offered in Connecticut, Massachusetts, New Jersey, New York, Pennsylvania, and Rhode Island.

RECs provide another alternative to switching electricity suppliers. Also known as green certificates, green tags, or tradable renewable certificates (TRCs), RECs represent the "green" attributes of renewable energy generation and can be sold separately from commodity electricity. REC-based products may be supplied from a variety of renewable energy sources throughout the country and sold to customers nationally, or they may be supplied from renewable energy sources in a particular region or locality and marketed as such to local customers. More than 25 companies offer certificate-based green power products to retail customers via the Internet, and a number of other companies market RECs solely to commercial and industrial customers.[23]

RECs are also sold in the wholesale market and are frequently used by utilities and marketers who bundle RECs with commodity electricity to sell green power to retail customers. In fact, RECs are used to supply most of the programs where default suppliers have teamed with green

[21] For an up-to-date list of products offered by competitive green power marketers, see the U.S. Department of Energy's Green Power Network Web site at: http://apps3.eere.energy.gov/greenpower/markets/marketing.shtml?page=1.

[22] We do not include Oregon and Virginia in this list. In Oregon, only large commercial and industrial customers are able to switch to competitive green power providers; residential and small commercial customers have access to green power options offered by the incumbent utilities, which we categorize as green pricing. In Virginia, at least one retail electricity provider provided green power options in 2007 and earlier, but does not do so currently.

[23] For an up-to-date list of companies offering REC-based green power products, see the U.S. Department of Energy's Green Power Network Web site at: http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=1. For a list of REC suppliers serving commercial or wholesale customers, see: http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=4.

power marketers. Therefore, it can be difficult to distinguish REC products from other green power offerings. This is particularly true when REC products are supplied from renewable sources located in the same region where they are marketed.

REC and Competitive-Market Products and Pricing

Green power products offered in competitive markets tend to differ from those offered by utilities in regulated markets, as they are more likely to be sourced from RECs because suppliers may be less able to enter into long-term contracts with generators. In addition, price premiums may fluctuate more frequently.

Initially, green power marketers in competitive markets were often forced to offer existing renewables because of a lack of "new" renewable energy supplies, but most marketers now offer primarily new renewables. In 2008, about 85% of competitive-market and REC sales were supplied from new renewable energy sources. This movement toward increased reliance on new renewables has also been encouraged by green power product certification programs, which set standards for product quality, and have required increasing amounts of "new" renewables. Beginning January 1, 2007, the *Green-e Energy* certification program began requiring that all certified products be supplied exclusively from "new" renewable energy projects.[24] Similarly, the U.S. Environmental Protection Agency's (EPA) Green Power Partnership requires its partners to purchase "new" renewables to meet its purchase criteria.[25] Both Green-e and EPA define "new" as those facilities put into service on or after January 1, 1997, which is generally considered to be the inception of the voluntary green power market.

The price premium charged for competitive-market products depends on several factors including the price of standard offer or default service, the availability of incentives to green power marketers or suppliers, and the cost of renewable energy generation available in the regional market. Some marketers have charged prices close to or even below the default market price in recent years (e.g., in Texas); others have offered fixed-price products, providing customers with protection against increasing prices for a specified period of time, usually one year.

Competitively marketed green power products generally carry a price premium of between 1¢/kWh and 2.5¢/kWh for residential and small commercial customers, although offerings have ranged from small discounts to a premium of about 10¢/kWh in recent years. In addition, price premiums can change frequently with changes in market conditions. Higher-priced products often contain a larger fraction of "new" renewable energy content or resources that are more desirable to consumers, such as new wind and solar.

Similar to competitively marketed products, retail prices charged for REC products typically range from about 1¢/kWh to 2.5¢/kWh for residential and small commercial customers, although some are priced as high as 5.5¢/kWh. In most cases, larger customers are able to negotiate lower

[24] Administered by the San Francisco-based Center for Resource Solutions, the *Green-e Energy* program certifies retail and wholesale green power products that meet its environmental, product content, and marketing standards. For details on the *Green-e Energy* National Standard, see the *Green-e* Web site at: http://www.green-e.org/.
[25] See the EPA's Green Power Web site at: http://www.epa.gov/greenpower.

prices. Nearly all REC products are sourced from new renewable energy generation projects as a result of product certification requirements.

REC buyers often seek certification out of concerns over "double counting" and to ensure a level of oversight and auditing because RECs are generally not subject to the same regulatory scrutiny as electricity and mandatory renewable requirements. Table 13 shows *Green-e Energy* certified retail transactions in 2007 and 2008. *Green-e Energy* certified more than 13 billion kWh of retail transactions in 2008. Compared to NREL's total voluntary market retail sales figure of 24 billion kWh, *Green-e Energy* certified 54% of voluntary market retail sales (Karelas 2009).

Table 13. Total Retail Sales of *Green-e Energy* Certified Renewable Energy, 2007 and 2008 (Million kWh)

	Residential		Commercial		Total Retail	
Year	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**
RECs	82	50	7,305	10,490	7,387	10,540
Green Pricing	834	1,413	367	753	1,201	2,166
Competitive Electricity	148	171	250	170	398	341
Total	1,064	1,634	7,922	11,413	8,986	13,047

Source: Karelas 2009

The *Green-e Energy* program also certifies wholesale renewable energy transactions, which exceeded 13 billion kWh in 2008. It is important to note that 8.2 billion kWh sold in certified wholesale transactions were resold in *Green-e Energy* certified retail transactions. The remaining 4.9 billion kWh were sold in non-*Green-e Energy* certified transactions, most likely to utilities and electric service providers, power marketers, or retail customers.

Removing the instances of renewable energy certified by *Green-e Energy* at both the wholesale and retail levels, *Green-e Energy* certified sales of 17.4 billion unique kilowatt-hours in 2008. This is an increase of 49% from 2007. Assuming that all kilowatt-hours certified at the wholesale level were ultimately sold in retail voluntary sales, 74% of the total kilowatt-hours sold in the retail voluntary market in 2008 were involved in a *Green-e Energy* certified transaction at some point in their chain of custody.

REC and Competitive-Market Customer Participation

Based on data received from green power marketers, we estimate that nearly 425,000 retail customers were buying green power from competitive suppliers or as unbundled RECs at the end of 2008 (Table 14). This number includes nearly 122,000 participants in utility/marketer programs available in competitive markets. Participation in utility/marketer partnership programs in competitive markets has doubled since 2005, although the number of customers remained relatively constant between year-end 2007 and 2008. Figure 5 shows growth both in sales and customer participation in utility/marketer programs in competitive markets. Between 2005 and 2007, sales and customer growth rates were nearly equivalent; but, in 2008, customer numbers grew by only 4% compared to 35% growth in sales.

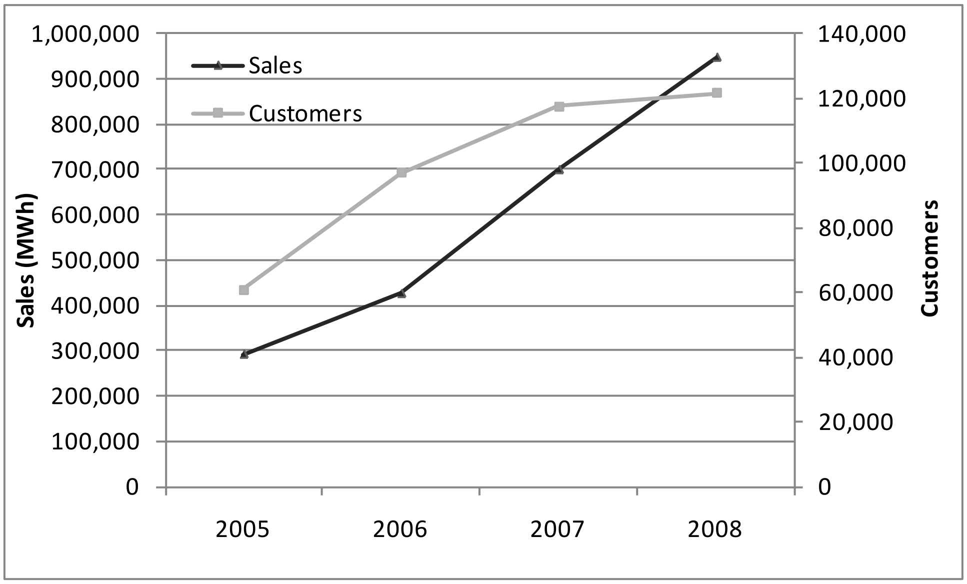

Figure 5. Growth in retail sales and customer participation for utility/marketer partnerships in competitive markets, 2005-2008

In competitive markets, the vast majority of customers buying green power are residential customers. Of the approximately 425,000 retail customers in competitive markets, fewer than 10% purchase REC-only products. The number of REC-only buyers increased from about 13,000 to 30,000 customers in 2008, showing some increase in traction with residential consumers—but the fraction of overall customers in the market is still quite small. The reason for the increase in residential REC purchasers is unknown, but could be a result of more targeted efforts to market RECs to residential consumers in some regions. While most of the REC buyers are residential customers, the majority of REC sales on a kilowatt-hour basis are made to nonresidential customers due to the much larger purchase sizes.

Table 14. Estimated Cumulative Number of Customers Buying RECs or Green Power from Competitive Marketers, 2003-2008

	2003	2004	2005	2006	2007	2008
Competitive Markets	~170,000	<140,000	>180,000	~ 210,000	~300,000	~390,000
RECs*	<10,000	<10,000	<10,000	~ 10,000	~13,000	~30,000
Total	**~180,000**	**<150,000**	**~190,000**	**~ 220,000**	**>310,000**	**~425,000**
% Change	13%	-17%	27%	16%	37%	37%

*Includes only end-use customers purchasing RECs separate from electricity.
Note: Totals may not add due to rounding.

In recent years, most of the customer gains in competitive markets resulted from utility/marketer partnership programs in the Northeast as well as customers who switched from default service to retail green power providers in a few states, most notably Texas. These gains have been tempered by losses in some states, where marketers have struggled to provide electricity service to consumers amidst adverse market conditions and increasing costs. During 2007, EIA data show declines in the number of green power customers in Virginia but gains in Texas, Maryland, Pennsylvania, and Washington, D.C (see Appendix C).

REC and Competitive-Market Green Power Sales

An estimated 19.5 billion kWh of renewable energy was sold to retail customers by competitive green power and REC marketers in 2008 (Table 15). This figure includes renewable energy from both pre-existing and new sources. In 2008, about 85% of the REC and green power competitive-market retail kilowatt-hour sales were supplied from new renewable energy sources.

An estimated 3.9 billion kWh were sold as a bundled green power product in competitive electricity markets—more than a 20% increase from 2007. The competitive-market sales figure includes renewable energy sales through default utility/marketer programs or individual utility/marketer partnerships in competitive markets, which amounted to approximately 950 million kWh in 2008, a 35% increase from 2007 (see Figure 5). Retail REC sales increased by nearly 50%, reaching 15.6 billion kWh in 2008. Most of the growth in REC-only sales is attributable to the nonresidential sector.

Table 15. Retail Sales of Renewable Energy in Competitive Markets and RECs* (Million kWh), 2004-2008

	2004	2005	2006	2007	2008
Competitive Markets					
Residential	2,140	1,330	1,000	1,800	2,700
Nonresidential	510	820	710	1,400	1,200
Subtotal	**2,650**	**2,150**	**1,720****	**3,200**	**3,900**
% Change	40%	-19%	-20%**	88%**	22%
% Residential	81%	62%	59%	56%	69%
Unbundled RECs* **					
Residential	40	40	110	60	200
Nonresidential	1,690	3,840	6,700	10,500	15,400
Subtotal	**1,720**	**3,890**	**6,810**	**10,500**	**15,600**
% Change	160%	126%	75%	55%	49%
% Residential	2%	1%	2%	1%	1%
Total Sales	**4,370**	**6,040**	**8,530**	**13,800**	**19,500**
% Change	**71%**	**38%**	**41%**	**62%**	**41%**

*Totals may not add due to rounding.
**2006 are likely underestimated because of data gaps.
***Includes only RECs sold to end-use customers separate from electricity.

Table 15 also delineates green power sales by customer segment. In 2008, residential customers represented more than two-thirds of green power sales in competitive markets. In contrast, nonresidential customers represented nearly all unbundled REC sales. Generally, nonresidential customers find REC-only products attractive because of their flexibility and the greater potential for cost savings because they can be sourced from renewable energy projects in more favorable resource locations; also, the electricity does not have to be delivered directly to the customer, which lowers transaction costs. On the other hand, residential customers may not be aware that RECs are available or may not understand them. As noted above, the slight uptick in residential REC purchasers in 2008 may have resulted from more targeted efforts to market RECs to residential customers in some regions; however, the actual cause of the increase is not known. For commercial and institutional customers that operate facilities in multiple locations across the country, RECs may also provide a more efficient green power sourcing solution than working with utilities in each individual utility territory.[26]

In 2008, renewable energy sold in competitive markets or as unbundled RECs represented an equivalent renewable energy capacity of nearly 5,800 MW, with almost 4,900 MW of this total coming from "new" renewable energy resources (Table 16). This is up from 3,700 MW of equivalent capacity and 3,000 MW of new capacity in 2007. Equivalent figures for 2006 are 2,400 MW and 2,100 MW, respectively. Capacity estimates for earlier years are provided in Table 4 and Appendix A.

Table 16. Renewable Energy Sources Supplying Competitive and REC Markets, 2008

	Biomass/ Landfill Gas	Geo-thermal	Hydro	Solar	Wind	Unknown	Total
MWh Sales	3,697,000	345,000	2,124,000	23,000	13,293,000	44,000	19,526,000
% of Total Sales	19%	2%	11%	0.12%	68%	<1%	100%
Total MW	**500**	**40**	**610**	**20**	**4,590**	**10**	**5,770**
MW New RE	**420**	**3**	**130**	**20**	**4,270**	**--**	**4,860**

Information on new content is unavailable in some instances.

[26] For example, the EPA Green Power Partnership reports that the majority of its Top 25 partners purchase RECs (Appendix B), see http://www.epa.gov/greenpower/. In addition, the Green Power Market Development Group promotes the purchase of RECs among its members, see the organization's Web site at: http://www.thegreenpowergroup.org/.

The Voluntary Carbon Offsets Market

Green power markets are affected by other related markets, such as the emerging U.S. market for greenhouse gas (GHG) offsets. Because green power and GHG offset markets have converged in recent years, this section addresses GHG offsets sourced from renewables. A GHG offset (sometimes referred to as a carbon offset) is a tradable commodity representing a unit of GHG emissions reduction or avoidance—typically, one metric ton of carbon dioxide equivalent (CO_2e). Corporations and individuals are buying these products to "offset" their own emissions, such as those associated with energy used for heating, product manufacturing processes, automobile use, and air travel.

GHG offsets can be derived from a variety of project types that reduce or avoid GHG emissions, which use diverse methods for measuring these reductions. Examples of GHG reduction projects include renewable electricity generation, energy efficiency measures, methane capture at landfill sites, soil carbon sequestration, and forestry projects. Developers of these project types can sell GHG offsets to consumers or businesses to help finance their projects. For GHG offsets sourced from renewable energy generation projects, the equivalent emissions reduction of replacing conventional generation with renewable generation must be calculated. More than 25 companies offer offset products derived at least, in part, from renewable energy generation projects.[27]

Offsets sourced from renewable energy differ from green power in that they are sold in tons of CO_2e, while RECs and other forms of green power are sold in kilowatt-hours. In addition, certification standards for offsets differ from those for renewable energy and not all RECs can be converted to offsets. Generally, offsets must demonstrate additionality, meaning that the emissions reductions are additional to what would have occurred anyway (or under business as usual). Retail customers typically purchase green power or RECs equivalent to a portion or all of their electricity consumption. In contrast, retail customers buying GHG offsets generally purchase tons of CO_2e to match their carbon emissions. There is overlap in the sense that many green power purchasers are motivated to buy green power for their electricity consumption out of concern about climate change and to address their electricity-related GHG emissions. Currently, renewable energy could provide either a GHG offset (ton of CO_2) or a kilowatt-hour of green power—however; there are double-counting concerns if the same kilowatt-hour is sold as both an offset and a REC. Certifiers generally do no allow this type of double counting.

Eight out of approximately 20 GHG offset providers that offer products at least partially sourced from U.S.-based renewable generation reported 2008 offset sales to NREL. The carbon offsets sourced from renewables totaled nearly 250,000 metric tons of $C0_2$ equivalent, which is equivalent to about 340,000 MWh of renewable energy generation.[28]

[27] The Green Power Network tracks GHG offset providers and products that are available nationally and are derived at least in part from U.S.-based renewable energy generation projects

[28] The EPA's national average electricity emissions factor for nonbaseload generation (eGRID 2009) was used to estimate the equivalent in MWh.

Table 17. GHG Offsets Sourced from U.S.-Based Renewable Energy Sources, 2008

	Metric Tons CO2e	Equivalent in MWh
Residential	31,200	43,500
Non Residential	214,700	299,000
Total	**245,900**	**342,500**

Several independent certifiers have created standards for verifying emissions GHG reductions to ensure that they are real, measurable, and beyond business as usual and any regulatory requirement. They also establish ownership of the actual emission reductions so that multiple parties do not claim the carbon reduction. GHG offset providers responding to the NREL questionnaire reported that some, if not all, of their offsets were verified by the following organizations: Center for Resource Solutions,[29] Environmental Resources Trust,[30] or the Chicago Climate Exchange (CCX).[31]

Proposed federal or regional cap and trade programs have the potential to impact the ability for renewables located within capped regions to provide GHG offsets once emissions caps take effect, depending on program design details. Because renewables provide indirect emissions reductions by displacing emissions from fossil fuel generators, they may not have a claim to the emissions reductions under a cap and trade program, unless provisions such as allowance set asides are adopted. The Regional Greenhouse Gas Initiative in the Northeast, the only cap currently in effect in the U.S., includes a voluntary renewable energy set aside through which states retire CO2 allowances on behalf of voluntary renewable energy purchases, ensuring emission reductions associated with the renewable generation.

[29] In February 2008, the Center for Resource Solutions certified its first retail products under Green-e Climate, a consumer-protection program requiring verification of GHG reductions based on a project-level certification program that ensures the reductions have taken place, are permanent, and come from projects that would not have happened under a "business-as-usual" scenario. Sellers must undergo a yearly audit to ensure their supply of offsets matches their sales, and comply with Green-e Climate's consumer-disclosure and truth in advertising requirements. The Green-e Climate Protocol for Renewable Energy requires that GHG emissions reductions from renewable energy must meet all the Green-e Climate verification standards as well as additionality requirements to ensure that they are beyond business as usual. The protocol requires that the RECs associated with the renewable energy generation certified under Green-e Climate be retired and not resold in the voluntary green power markets or used for compliance with renewable energy standards. The generator and/or seller must verify that the attributes are only sold once, and not double counted. For more information, see the protocol at http://www.green-e.org/docs/climate/Green-e_Climate_Protocol_for_RE.pdf.

[30] The Environmental Resource Trust/Winrock International verifies carbon offsets in partnership with the American Carbon Registry. The American Carbon Registry allows flexibility for members to choose among methodologies set out by the Clean Development Mechanism (CDM) and the Voluntary Carbon Standard (VCS). A carbon offset is considered an emissions reduction ton (ERT) if it is real, additional, permanent, and that ownership is incontestable. After verification, the Registry assigns each offset a unique serial number. For more information on the ERT certification, see http://www.winrock.org/common/files/Solution_Stories/acr_capabilities.pdf.

[31] The Chicago Climate Exchange guidelines for carbon offsets sourced from renewable energy generation were established in 2006. To qualify, RE systems must have been activated on or after January 1, 2005. Project proponents must demonstrate ownership rights associated with the environmental attributes, (i.e. must not have sold the RECs, or used them for compliance purposes). Under the verification process, for CCX Offsets to be issued, the RECs are surrendered to and retired by CCX. For more information on the CCX guidelines, see http://www.chicagoclimatex.com/news/publications/pdf/CCX_Renewable_Offsets.pdf

Voluntary Green Power Market Trends and Issues

As the voluntary green power market continues to grow, a few trends and issues have surfaced. This section explores the appropriate level of marketing costs for utility green pricing programs, highlights trends in REC prices in both the compliance and voluntary markets, and explores the future role of the voluntary market as compliance markets expand.

Program Marketing Expenditures: Finding the Right Balance

In 2008, some market observers raised concerns about optimal levels of spending for marketing green pricing programs. As a percentage of program revenues, programs spent a median of 18.8% on marketing their program in 2008 and 16.6% in 2007, with the smallest utilities (with less than 25,000 in their eligible customer base) spending 49% of revenues, significantly more than the overall median. Figure 6 shows 2008 marketing and administration expenditures by utility size.[32]

Figure 6. Average program marketing and administration expenditures (2008), by utility size

[32] Some caveats must be understood with respect to these data. Programs' data collection methods and proficiency tend to be inconsistent. There is no single set of accounting definitions to which programs adhere. Some programs do not collect these data at all, and some collect but do not report it to NREL. In addition, there is likely an inherent "survivorship" bias, or tendency for programs to under-report data showing poor results or high acquisition costs. Several programs either have no budgets or rely on broader utility marketing budgets for some or all of their marketing expenditures and/or labor costs. In such cases, these costs are paid for by all ratepayers rather than solely by program participants, resulting in a lower reported expenditure. The recent increased scrutiny on these data suggests improving and standardizing accounting and collection practices.

Budgets for marketing and administration of green pricing programs are a function of several factors: the region of the country; the size of the utility service area; the customer base and media markets encompassed within that service area; the point or stage in the lifespan of the program; and certainly, not least, the utility's commitment to and goals for the program. All of these factors vary significantly among programs.

Conclusions about what might be the optimal level of program expenditures for marketing often rest on whether such expenditures are framed as consumer education in the public interest. As in many businesses, programs must balance investing in consumer education, expanding program participation, keeping participation affordable, and maintaining standards for product quality and supporting new renewable energy development. These goals are not mutually exclusive; strong marketing has been shown to support robust participation, which can enable a program to support more new renewable energy projects. How a program strategy is designed depends on what the strategy is meant to accomplish. Some utilities have comprehensive environmental goals or goals intended to green their brand. Other utilities aim only to make a renewable option available to customers and spend little or nothing on marketing.

While program experience has shown that marketing expenditures are important for program growth, the question of the optimal amount of marketing expenditures has arisen largely in the context of product quality, specifically around the perception that participant dollars could be better put to use through greater investment in more new renewable capacity than in marketing. Yet active marketing need not come at the expense of product quality—spending more to attract more participation can instead grow the size of the market and result in more new development.

Like any new business, some programs tend to spend more on marketing in their "start-up" phase (the first two to three years of a new program), during which time the program feels its greatest burden to educate customers about the new offering and entice them to enroll. Even those that do not spend significantly more on marketing in early years subsequently spend less as a percentage of revenues over time, simply because their revenues tend to increase over time. Like any business, the start-up phase is a relatively costly investment for which programs sometimes do not see a return for several years.

In the start-up phase of a business—which can be a different length of time for different industries—the new business has a disproportionate need to spend money on several cost components that tend to lessen in subsequent years. These include the following:

- Hiring and training staff and call center representatives
- Conducting market research
- Developing a business plan and designing the program
- Establishing a brand and building product awareness
- Identifying the target market and message
- Building a Web site
- Identifying and purchasing wholesale products
- Developing and creating marketing materials
- Establishing mechanisms for billing and for processing sales.

On the other hand, it can become more costly to attract customers in the later years in the life of a program, after the "low-hanging fruit"—the customers most inclined to sign up—are already enrolled. In this later phase, some programs engage in more expensive marketing tactics, such as direct mail or telemarketing. Program managers might do this for a combination of reasons. For example, they might conclude that the less expensive bill inserts or bangtails have accomplished what they can, they could be limited in the number of bill inserts that their program can use because of competition from other internal utility programs, or they might tailor specific messages to residential customer segments that have been less inclined to participate. As a result, marketing costs could increase again in the later years of a program.

The question of program marketing expenditures inevitably leads to broader issues of program transparency, the value customers are receiving for their premium, and the question of how well the expenditures are accomplishing their stated goals. On the question of transparency, the *Green-e Energy* certification program, which has become the leading certification standard for green pricing programs, does not require public disclosure of the renewable energy projects supported by a green pricing program, or disclosure of the budgets or breakout data on program expenditures. However, some consumer advocates have said that a "best practice" standard should include project disclosure, contending that consumers have a right to know which projects their premiums are supporting.

To better understand recent concerns about marketing costs, particularly among investor-owned utilities, it is useful to view current issues in light of the original impetus for green pricing. The first programs were launched in the mid- to late 1990s during the movement toward retail electricity restructuring and its concomitant emphasis on customer choice. Green pricing programs were by design the first, and they remain the only, non-price-based differentiator for electricity commodity. They are the only option for customers to choose electricity not as a commodity but as a product reflecting customer values.

Yet from the outset, customer confusion about the new product made consumer education a necessary element to the success of green pricing programs. Such educational efforts, and the increased costs associated with them relative to other utility programs, have been supported by some regulators as squarely within the public interest. This is primarily because of the product's promise as a solution to environmental and other public concerns, and the notion of the public's interest in having a value-based choice in their energy supply.

Product or Donation: Why has the question of marketing expenditures arisen?

It is unusual for the level of a private, unregulated for-profit company's marketing expenditures to be questioned, although charities may face such questions. One would assume that a company has incentive to spend only the amount of money justified by the expected return on that expenditure, so that the free market can be trusted because of these built-in incentives. But energy is a regulated industry, and regulators are charged with protecting customer value. In addition, green pricing programs bear similarities to charitable organizations and may well be facing more scrutiny because of those similarities. In fact, some utilities have marketed programs as charitable contributions which, in some cases, are tax-deductible.[33] However, the industry has more typically framed green power conceptually as a "product," a quantity of renewable energy that matches all or part of consumers' electricity consumption. Of the more than 850 U.S. green pricing programs, about 15-20 call themselves "contribution" programs.[34]

Unlike private businesses, charitable organizations' value *is* evaluated in part on how little they spend on marketing and administration. The question is asked far less of for-profit companies. And, in the case of green pricing programs, if *more* marketing expenditure results in greater demand for renewable energy or in greater program participation, should that reduce the importance of the question of how much was spent on marketing? In determining optimal levels for programs to spend on marketing, it is helpful to appreciate the ambiguity in the nature of the green pricing product and premium. Is the premium a *payment* for a product or a *donation* supporting a cause? Customers are purchasing a product, in that in the vast majority of programs, they are paying for a specific quantity of renewable energy to match their electricity consumption. Yet green pricing programs bear important similarities to charities. The comparison of green pricing programs to charities is made for several reasons. Perhaps the most important is the similarity in messaging, with its emphasis on doing the right thing, "making a difference," and the legacy message with a call to action for future generations and for the environment. Similar to charitable organizations, green pricing programs typically craft "cause marketing" messages that resemble a request for a donation in that an appeal is made to make a difference or do the right thing. Typical examples of marketing claims and calls to action in green pricing marketing materials include the following:

- a…way to support our environment.
- leaving our family a brighter future.
- develop new renewable energy resources.
- make an impact…on the environment.

In addition to the messaging similarities to "cause" marketing, there is a question regarding the green power product itself: Because it has no tangible personal benefit or, at the very least, the benefit is *primarily* public, can it be said that those "buying" it are buying a product? The similarity to charitable causes is an important one in the context of marketing expenditures, because it is only in this similarity that the question has been asked in the first place; companies selling products and services are rarely, if ever, scrutinized on this basis. In their 2008 case before the Florida Public Service Commission, Green Mountain Energy Company raised the applicability of the question, as follows:

"*[A] utility company might contract with a local General Motors dealer to purchase a fleet of trucks. The utility pays the dealer the agreed-upon price… After the dealer has covered the cost of purchasing and delivering the trucks, any revenue left over from the purchase price belongs to the dealer. Any inquiry into the dealer's advertising, selling or other costs is inappropriate and demonstrates a misunderstanding of the legal and economic basis of the relationship between the dealer and FPL.*"

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[33] For example, NC Greenpower, a program which is offered to utility customers throughout North Carolina, offers tax deductions for "contributions" to the green power program. For more information, see http://www.ncgreenpower.org/signup/online_contributions.html.
[34] For more information, see greenpower.energy.gov.

The green pricing premium could be compared to a donation to public radio, where consumers and businesses "buy" the product for their neighbors, not just for themselves; they pay for a service they are receiving and for a public good at the same time. On the other hand, because green pricing participants are receiving a product tied to specific quantities based on the amount of energy they use, the purchase could also be seen as more akin to a product purchase than a charitable donation—in these cases, people generally donate money based on what they can afford or wish to contribute.

Energy-based green pricing programs can be distinguished from charities on the basis of the specific amount of energy delivered to the grid. When making a charitable contribution, donors give what they can afford in expectation that the beneficiary will put their contribution to "good use." The efficacy of the charity is judged in part on the portion of the donation spent on the "cause." This ratio is not always known at the time the donation is solicited. In addition, because some companies now use renewable energy to claim emissions reductions, it is important to understand that such claims are made on the basis of a purchase of renewable energy, as distinguished from a donation.

In contrast, an energy-based green pricing program typically offers a firm quantity of renewable energy at a firm price. The price, terms, and conditions are disclosed in standardized language in most cases and always in the case of *Green-e Energy* certified programs. For example, when programs offer a 100% usage option, if a customer on average uses 1,000 kWh per month and the offered green premium is 1.5 cents per kWh, then the consumer can be confident that the enrollment will result in 1,000 kWh of renewable energy being added to the grid at a cost of $15 per month added to their bill. The customer can evaluate whether they perceive the offering to be a good value.

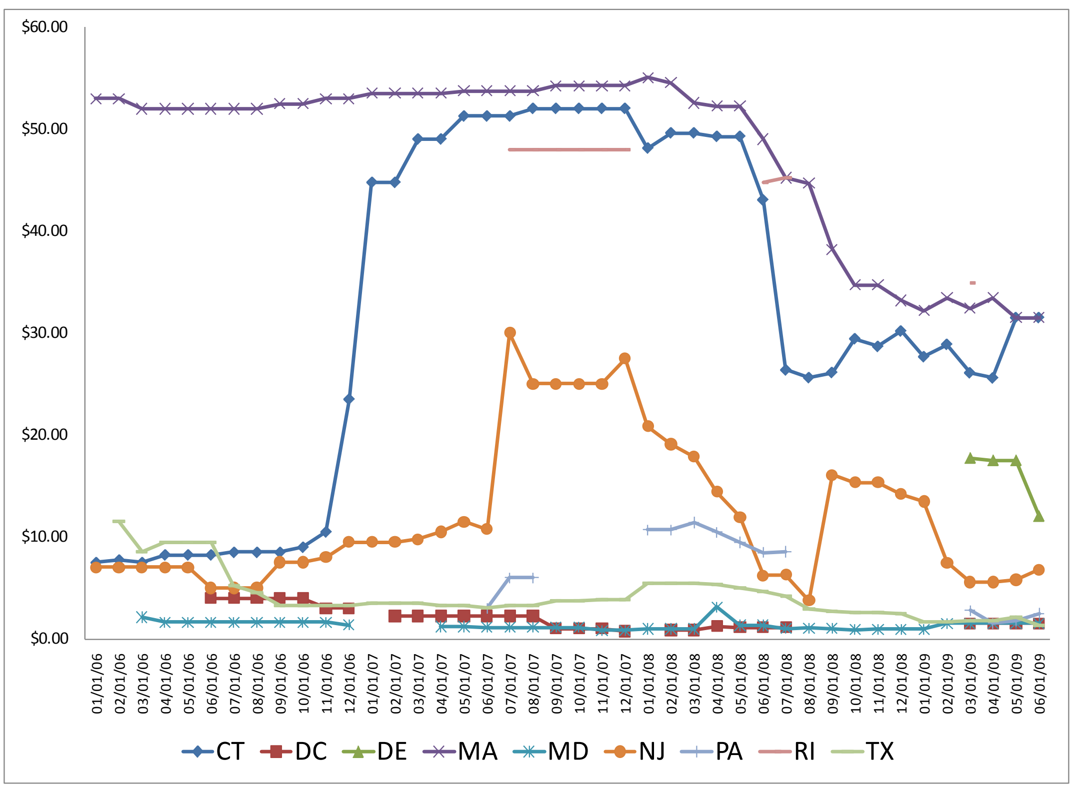
In the final analysis, it is only in considering the hybrid nature of voluntary programs that a balanced assessment of "how much is too much" marketing costs can be made. Furthermore, there is no clear optimal level of marketing expenditure; rather, appropriate costs may vary by type of program, customer base, age of program, and a variety of other factors.

Renewable Energy Certificate Prices

This section provides an overview of wholesale REC prices in voluntary and compliance markets in recent years based on indicative data available from brokers and third-party data providers. With a few exceptions, there is little price transparency in REC markets. Most transactions are conducted as bilateral contracts between parties, and prices are not reported. In addition, prices can vary widely by region. Therefore, data presented here are only indicative and should be used with caution.

In general, REC values depend on a number of factors, including whether the RECs are bought to meet compliance obligations or serve voluntary retail consumers, the technology, the vintage (year in which it was generated), the volume purchased, whether they are eligible for certification, and the region in which the generator is located.

The region from which RECs are sourced is particularly important because often there are regional differences in renewable energy resource quality (i.e., wind speed) and electricity prices that determine the cost-effectiveness of the renewable generation. In addition, the supply and demand of RECs often varies regionally. In regions where there have been shortages of renewables to meet RPS requirements, REC prices have reached or come near to levels for alternative compliance payment (ACP) of $50-$55/MWh; whereas, in other states or regions, compliance RECs have sold for less than $5/MWh. Figure 7 shows the wide variation in compliance-market REC prices among states for which data are available.



Sources: Evolution Markets, Spectron Group, Barbose 2009

Figure 7. Compliance market (primary tier) REC prices, 2006 to mid-2009

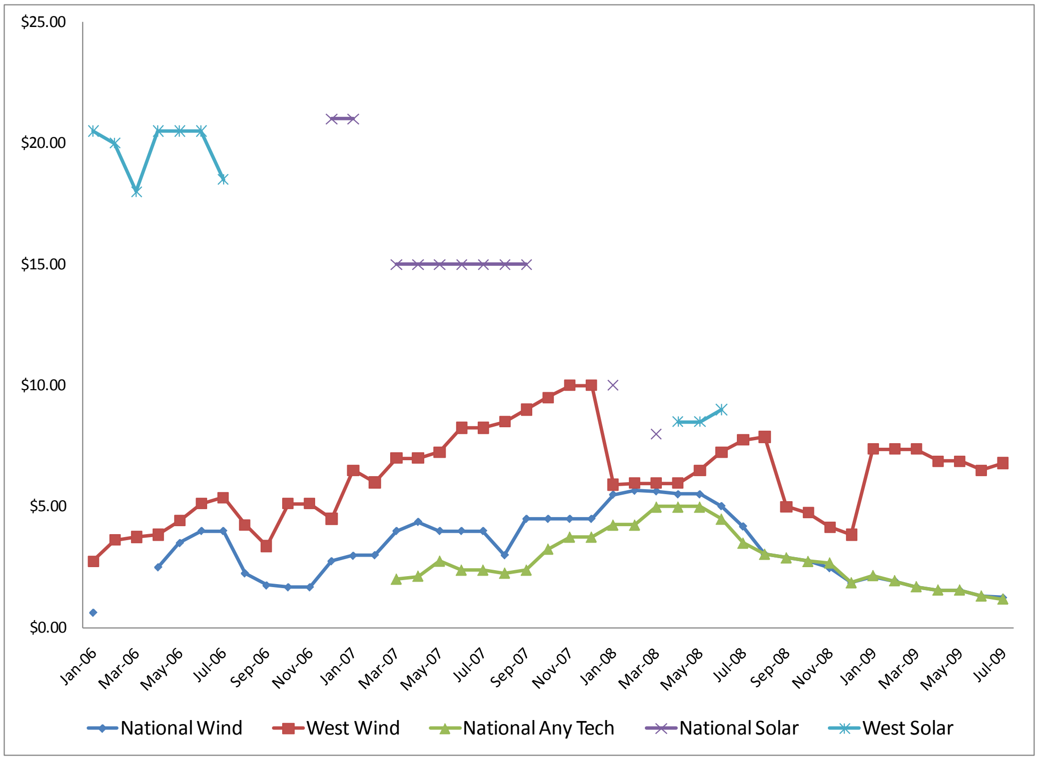
Solar RECs (SRECs) have higher value than RECs from other resource types in both compliance and voluntary markets. This is true for a number of reasons: 1) at least 18 state RPS programs have specific provisions to encourage solar or distributed generation (DG) (DSIRE 2009e); 2) the penalty price for noncompliance is often set higher for solar/DG tiers than for standard RPS compliance; and 3) SRECs can be desirable in the voluntary market, where customers may be willing to pay more for solar, which costs more than other renewables. Data availability is limited, but several price points are indicative of the higher market price for SRECs in compliance markets in 2009 (Table 18). Figure 8 compares voluntary solar RECs to generic and wind RECs. In the first half of 2008, both voluntary solar RECs (SRECs) sourced from anywhere in the nation and those from the Western region ranged from about \$7/MWh to \$10/MWh.

Table 18. 2009 Compliance Market SREC Prices

	Range of SREC Prices
New Jersey	\$665 -\$685
Delaware	\$225 - \$300
Maryland	\$350
Pennsylvania	\$275 - \$315

Source: Spectron Group 2009
Note: Values represent the midpoint of the bid and offer prices for current-year vintage.

While compliance RECs generally must be sourced from within some geographic region to be eligible for RPS compliance, voluntary RECs can be sourced either regionally or nationally. Most utility green pricing programs or marketers selling bundled electricity and REC products source their products from local or regional resources, with some exceptions. Buyers of nationally sourced RECs are often large corporations that have facilities in multiple locations across the country. In voluntary markets, RECs that are sourced locally (within the region) may have to compete with RPS demand or be subject to regional resource limitations. Therefore, regionally sourced RECs often sell at a premium to nationally sourced RECs, which are often derived from the most cost-effective renewable resources. As shown in Figure 8, wholesale RECs used in voluntary markets have generally traded in the range of \$1/MWh to \$10/MWh, based on available indicative data.



Sources: Evolution Markets, Spectron Group, Barbose 2009

Figure 8. Voluntary REC prices, 2006 to mid-2009

Table 19 presents wholesale REC prices for wind and for any renewable energy technology located nationally, as well as wind from within the Western Electric Coordinating Council (WECC). In 2008, prices paid for nationally sourced RECs from any technology ranged from about $1.50/MWh to $5.50/MWh; but, in the first half of 2009, these prices declined, ranging from about $1/MWh to $2/MWh (see Figure 8). Wind RECs, sourced both nationally and from WECC, netted higher prices, on average, than generic RECs sourced from any technology; but they also fell in late 2008. Prices differ not only by the technology and the location, but also by the vintage. Voluntary RECs sold in a given year can only be *Green-e Energy* certified if the renewable energy with which they are associated is generated in the calendar year in which the product is sold, the first three months of the following calendar year, or the last six months of the prior calendar year (CRS 2008). Table 19 shows price ranges for different vintages based on bids and offers in 2008 (ranges are based on the midpoint between bid and offer prices). Forward contracts for 2009 vintage RECs were sold at a slight premium during 2008.

Table 19. Range of Voluntary REC Prices in 2008 for Different Vintages ($/MWh)

Range Year	2007	2008	2009
National Any Technology	$1.5 - $4.7	$1.9 - $5.3	$2.7 - $5.5
National Wind	$1.5 - $4.7	$1.9 - $5.7	$2.7 - $6.1
WECC Wind	$2.3 - $6.4	$3.8 - $7.9	$6.1 -$8.6

Source: Spectron Group 2008

Regional REC Supply and Demand Balances

As the geographic coverage and stringency of state renewable portfolio standards (RPS) increases, and in light of the debate over a federal RPS, implementers have asked whether supplies will be adequate to meet these existing policies as well as demand from voluntary purchasers. Supply shortages have occurred in some regions, which has increased prices for RECs and limited supplies available to voluntary markets in a few instances. This has caused some concern that increased demand for renewables resulting from RPS policies will outstrip supplies and increase prices for RECs in coming years.

In an attempt to shed some light on these questions, a recent NREL analysis (Bird et al. 2009) examined the balance between the demand and supply of new U.S. renewable electricity on a regional basis through 2015. The analysis relied on estimates of renewable energy supplies compared to the demand for renewable energy generation necessary to meet existing state renewable portfolio standard (RPS) policies in 28 states as well as demand by consumers who voluntarily purchase renewable energy.[35] Note that the analysis did not consider the impacts of a potential federal RPS, only policies already in place. Two supply scenarios were examined: 1) a business-as-usual (BAU) scenario based on current growth rates in renewable energy supply in each region, and 2) a market-based scenario that differs only in an assumed higher overall level of wind energy development nationally (based on estimates from BTM Consult and referred to as "high wind case").

The analysis found an overall national surplus of renewable energy generation to meet existing RPS policy targets and voluntary market demand over the study period. However, based on the assumptions in the analysis, some regional shortages were projected, as well as regions with excess supplies. Figure 9 compares the two supply scenarios to renewable energy demand from RPS policies and voluntary markets in each of the regions considered in this analysis for 2015. It is important to note that the analysis did not take into account the effect of the global financial crisis, because of the uncertainty of the impacts.

Based on the assumptions in the analysis, deficits were projected for New England, New York, and the Mid-Atlantic areas, with notable surpluses in the Midwest, the Heartland, Texas, and the West. The BAU scenario, based on an extrapolation of recent development trends, found an internal shortfall for California; while, under the high wind energy scenario, California had excess generation except for one year (2010). The analysis did not assume trading among the regions specified in the analysis; however, in some cases, such trading may be feasible to the extent that it is not limited by transmission access or state RPS renewable energy certificate (REC) trading rules. For example, shortages in California—which is treated as an independent region in the analysis—could possibly be offset by surplus supply projected elsewhere in the West to the extent it can meet California's deliverability requirements.

[35] However, the analysis did not address demand by utilities that may procure cost-effective renewables through an integrated resource planning process or otherwise.

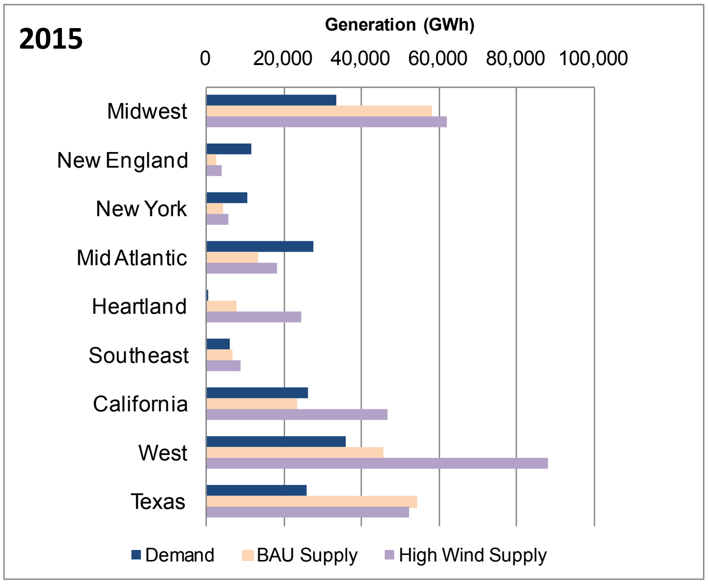


Figure 9. Snapshot of regional demand and supply under the two cases in 2015 (GWh)

In addition to interregional transfers where transmission is available, shortfalls could be addressed through price signals that may accelerate development of renewable energy resources that are currently uneconomic. This is particularly true in areas that have no or few market barriers. In areas with market barriers or transmission constraints, removing barriers to development, adding new transmission, and expanding interregional REC trading could alleviate potential regional shortfalls and enable states to access least-cost renewables. Key uncertainties in the analysis include the impact of the global financial crisis, potential changes in incentives or policies, the ability for renewable energy to access transmission, as well as the ability to develop offshore wind in the East.[36]

If renewable electricity shortages develop as projected in some regions by 2015, it is likely that REC prices will increase in those regions. Higher prices could dampen voluntary demand in affected regions, and RPS demand might even outbid some existing regional voluntary demand. However, prices for nationally sourced RECs would not necessarily be affected by regional shortages—as long as a national shortage does not develop, which has been the case in the recent past.

[36] While the pace of development in coming years will depend on the ability of the federal government and the financial industry to address the financial crisis and increase the availability of debt for project financing, the estimates presented in the analysis did not account for potential impacts of the crisis, because they are highly uncertain.

Conclusions and Observations

The green power market continues to exhibit strong growth and provide an important demand-driven stimulus for renewable energy development. Green power markets provide an additional revenue stream for renewable energy projects, and raise consumer awareness of the benefits of renewable energy. Based on this review, we have identified the following market trends:

- In 2008, total retail sales of renewable energy in voluntary-purchase markets exceeded 24 billion kWh, representing a capacity equivalent of 7,300 MW of renewable energy, including 6,300 MW from “new” renewable energy sources.
- Wind energy provided 71% of total green power sales, followed by biomass energy sources including landfill gas (17%), hydropower (9%), geothermal (2%), solar (<1%), with the remainder unknown (1%).
- Total market sales increased by nearly 35% in 2008, dominated by REC sales to nonresidential consumers, which increased by about 50%. Commercial and institutional REC markets now represent nearly two-thirds of green power market sales, surpassing sales in competitive electricity markets and utility green pricing programs.
- Overall, the total number of customers purchasing green power increased by nearly 15% in 2008, a slower rate than in previous years, with gains primarily in competitive and REC markets. Utility green pricing program participants remained essentially flat in aggregate, with some programs reporting customer losses, presumably due to the economic downturn.
- Utility green pricing programs in regulated electricity markets continued to grow on a sales basis, but at a slower rate than in previous years, with sales increasing by about 10% in 2008. A relatively small number of utility programs continue to dominate sales and customer numbers. In fact, the termination of one large program had a significant impact on market growth. Some programs experienced growth in sales even amidst customer losses, as a result of increased sales to commercial and institutional customers.
- Utility premiums for green pricing have continued to fall, which is attributed to a combination of higher prices of conventional generation fuels and lower renewable resource costs; however, these trends have become less clear with the economic declines in late 2008.
- In 2008, nearly 250,000 tons of CO_2e avoided from renewable energy facilities were marketed as offsets. This is the equivalent of about 340,000 MWh of renewable energy generation. Offset products sourced from renewables and sold to U.S. consumers are being certified by a number of organizations including CCX, *Green-e Climate*, and ERT.
- In 2008, sales to nonresidential customers continued to outpace those to residential customers, bringing the fraction of nonresidential sales to more than three-quarters of all green power sales on a kilowatt-hour basis. The growing dominance of nonresidential sales is a departure from the early history of green power markets when most products and programs were oriented toward residential customers.

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Appendix A. Estimates of New Renewable Energy Capacity Serving Green Power Markets, 2000-2004

Prior to 2005, estimates of the capacity serving green power markets were estimated based on renewable energy projects used to serve green pricing programs rather than derived from renewable energy sales. Therefore, the 2005 and more recent capacity estimates are not directly comparable to capacity estimates from previous years. However, the two approaches yield relatively consistent results.

Bird and Swezey (2005b) provide details on the derivation of capacity estimates for 2004 and earlier. Table A-1 presents estimates of the cumulative new renewable energy capacity serving voluntary markets from 2000 to 2004. A brief description of the methodology is included below.

Table A-1. Estimated Cumulative New Renewable Energy Capacity Supplying Green Power Markets, 2000-2004* (Megawatts)

Market	**2000**	**2001**	**2002**	**2003**	**2004**
Utility Green Pricing	77	221	279	510	706
Competitive Markets/RECs	**90**	**542**	**695**	**1,126**	**1,528**
Total**	167	764	974	1,636	2,233

*Data not directly comparable with Table 4.
**Totals may not add due to rounding.
Source: Bird and Swezey (2005b).

The estimates of capacity serving green power markets for 2004 and earlier focus on *new* renewable resources used to serve green power customers. New renewable resources are defined as projects or portions of projects built specifically to serve green power customers, or recently constructed projects that are used to supply green power customers and meet the regional *Green-e Energy* National Standard requirement to have come online on after January 1, 1997. The estimates do not include pre-existing renewable energy projects used for green power supply, or capacity used to meet state RPS requirements or other renewable energy mandates.

These estimates generally include the entire capacity of a given renewable energy project, regardless of whether the output has been fully subscribed by green power buyers (i.e., if a utility or developer completed a project before the entire output was sold to prospective customers). Therefore, the estimates may include some capacity for which a green power buyer was not yet secured. However, in cases where a portion of a project is used to meet a renewable energy mandate, only the remainder of the project is counted.

Appendix B. Leading Purchasers in the EPA Green Power Partnership

Table B-1. Top 25 Purchasers in the EPA Green Power Partnership Program, July 7, 2009

Ranking	Company	Annual Green Power Usage (kWh)	GP % of Total Electricity Use	Resource Type
1	Intel Corporation	1,301,300,000	48%	Biogas, Biomass, Geothermal, Small-hydro, Solar, Wind
2	PepsiCo	1,226,403,121	100%	Various
3	Whole Foods Market	790,459,000	105%	Solar, Wind
4	Kohl's Department Stores	600,990,000	50%	Biogas, Biomass, Small-hydro, Solar, Wind
5	Dell Inc.	553,708,000	158%	Biogas, Solar, Wind
6	City of Houston, TX	438,000,000	34%	Wind
7	U.S. Air Force	426,274,291	5%	Biogas, Biomass, Solar, Wind
8	The Pepsi Bottling Group Inc.	426,239,848	100%	Various
9	Cisco Systems Inc.	400,996,000	46%	Wind
10	Commonwealth of Pennsylvania	400,000,000	40%	Biomass, Wind
11	Johnson & Johnson	386,455,711	34%	Biogas, Biomass, Small-hydro, Solar, Wind
12	City of Dallas, TX	333,659,840	40%	Wind
13	HSBC North America	300,000,000	93%	Wind
14	U.S. Environmental Protection Agency	285,000,000	100%	Biogas, Biomass, Geothermal, Wind
15	Wal-Mart Stores, Inc/ California & Texas Facilities	243,328,000	8%	Solar, Wind
16	City of Chicago, IL	214,635,000	20%	Biomass, Wind
17	Starbucks	211,291,000	20%	Wind
18	Kimberly-Clark Corporation	192,730,000	7%	Biomass
19	University of Pennsylvania	192,727,000	46%	Wind
20	U.S. Department of Energy	188,599,600	4%	Various
21	DuPont Company	180,075,000	4%	Biomass, Solar, Wind
22	Wells Fargo & Company	175,000,000	14%	Wind
23	Los Angeles County Sanitation Districts	171,144,000	54%	Biogas
24	Deutsch Bank AG	160,000,000	97%	Wind
25	PepsiAmericas Inc.	157,128,393	100%	Various

Source: http://www.epa.gov/grnpower/toplists/top50.htm

Appendix C. Estimated U.S. Green Pricing Customers by State and Customer Class, 2006 and 2007

Table C-1. Estimated U.S. Green Pricing Customers by State and Customer Class, 2006 and 2007

State	Electric Industry Participants 2007 [a]	Participating Customers			
		2007			2006
		Residential	Non-Residential	Total	Total
Alabama	9	580	5	585	163
Alaska	1	520	10	530	356
Arizona	5	9,125	160	9,285	1,933
Arkansas	0	0	0	0	0
California	11	56,380	2,296	58,676	47,527
Colorado	23	55,635	1,866	57,501	48,093
Connecticut	3	90	6	96	0
Delaware	9	7,322	1,592	8,914	2,568
District of Columbia	3	1,351	3,503	4,854	3,716
Florida	6	37,536	297	37,833	29,301
Georgia	19	8,135	173	8,308	5,983
Hawaii	3	4,698	40	4,738	4,466
Idaho	6	4,669	148	4,817	4,130
Illinois	8	3,859	33	3,892	2,770
Indiana	14	4,244	55	4,299	2,039
Iowa	45	8,385	808	9,193	8,562
Kansas	1	1	0	1	0
Kentucky	13	1,322	16	1,338	889
Louisiana	0	0	0	0	0
Maine	2	2,266	228	2,494	2,146
Maryland	4	40,058	15,896	55,954	37,048
Massachusetts	5	5,882	273	6,155	5,655
Michigan	8	13,002	194	13,196	7,992
Minnesota	106	43,428	606	44,034	32,342
Mississippi	1	3	0	3	3
Missouri	17	1,417	22	1,439	459
Montana	13	974	21	995	460
Nebraska	5	6,831	60	6,891	4,887
Nevada	3	513	1	514	379
New Hampshire	1	0	1	1	0
New Jersey	3	146	295	441	363
New Mexico	13	19,339	1,934	21,273	15,577
New York	10	20,142	1,715	21,857	22,431
North Carolina	22	11,992	394	12,386	9,480
North Dakota	10	5,065	21	5,086	5,846
Ohio	14	1,784	5	1,789	252
Oklahoma	10	10,645	642	11,287	11,292
Oregon	17	97,400	3,195	100,595	80,733

State	Electric Industry Participants 2007 [a]	Participating Customers			
		2007			2006
		Residential	Non-Residential	Total	Total
Pennsylvania	4	38,301	798	39,099	37,355
Rhode Island	2	4,776	111	4,887	4,516
South Carolina	14	4,362	404	4,766	3,535
South Dakota	7	615	17	632	640
Tennessee	0	0	0	0	0
Texas	18	125,849	16,485	142,334	100,950
Utah	6	22,873	533	23,406	20,188
Vermont	2	4,281	236	4,517	4,537
Virginia	2	1,304	2	1,306	2,678
Washington	25	42,949	936	43,885	35,986
West Virginia	0	0	0	0	0
Wisconsin	60	34,252	2,092	36,344	31,335
Wyoming	8	9,090	4,135	13,225	3,606
Total	**591**	**775,398**	**62,260**	**835,651**	**645,167**

[a] Includes entities with green pricing programs in more than one state.
Note: Nonresidential may include some customers for whom no customer class is specified. Blank cells indicate no data was reported for the state or the number of customers in a class was zero. Totals may not sum due to rounding.
Source: Energy Information Administration, Green Pricing and Net Metering Programs, 2007. April 2009.
http://www.eia.doe.gov/cneaf/solar.renewables/page/greenprice/table5_1.html

Table C-2. Estimated U.S. Green Pricing Customers by Customer Class, 2002-2007

Year	Electric Industry Participants	Participating Customers		
		Customer Class		
		Residential	Non-residential*	Total**
2002	212	688,069	23,481	711,550
2003	308	819,579	57,547	877,126
2004	403	864,794	63,539	928,333
2005	442	871,774	70,998	942,772
2006	484	609,213	35,954	645,167
2007	591	775,398	62,260	835,651

*Note: Nonresidential may include some customers for whom no customer class is specified.
**Totals may not sum due to rounding.
Source: Energy Information Administration, Green Pricing and Net Metering Programs, 2006. July 2009. http://www.eia.doe.gov/cneaf/solar.renewables/page/greenprice/table4_h1.pdf and Green Pricing and Net Metering Programs, 2007. April 2009.
http://www.eia.doe.gov/cneaf/solar.renewables/page/greenprice/table5_1.html

Appendix D. Utilities Offering Green Pricing Programs in Regulated Markets, 2008

Table D-1. Utilities Offering Green Pricing Programs in Regulated Markets, 2008

Investor-Owned Utilities

AEP Appalachian Power
AEP Ohio
Alabama Power Company
Alliant Energy
AmerenUE
Arizona Public Service
Avista Utilities
Central Vermont Public Service
Cheyenne Light, Fuel and Power Company
Connecticut Light and Power
Consumers Energy
Dayton Power and Light
Dominion North Carolina Power
Dominion Virginia Power
DTE Energy
Duke Energy
El Paso Electric Company
Entergy Gulf States
E.ON U.S.
FirstEnergy
Georgia Power
Green Mountain Power
Gulf Power Company
Hawaiian Electric Company
Idaho Power Company
Indianapolis Power & Light Company
Kansas City Power & Light
Kentucky Power Co.
Kentucky Utilities Company
Louisville Gas and Electric Company
Madison Gas and Electric
MidAmerican Energy
Minnesota Power
NSTAR Electric
Nevada Power
Nevada Power
NorthWestern Energy
OG&E Electric Services
Otter Tail Power Company
PacifiCorp
Portland General Electric Company
Progress Energy
Public Service Company of New Mexico
Puget Sound Energy
SCE&G
Savannah Electric
Tampa Electric Company
Tucson Electric Power Company
UniSource Energy Services
United Illuminating
Upper Peninsula Power Company
Vectren Energy Delivery of Indiana
We Energies
Wisconsin Public Service Corporation
Xcel Energy

Electric Cooperatives

Alabama Electric Cooperative
Associated Electric Cooperative Inc.
Bandera Electric Cooperative
Basin Electric Power Cooperative
Boone Electric Cooperative
Buckeye Power
Central Electric Cooperative
Central Iowa Power Cooperative
Connexus Energy
Corn Belt Power Cooperatives
Dairyland Power Cooperative
Dakota Electric Association
Delaware Electric Cooperative
Deseret Power
Deseret Power/Mt. Wheeler Power Cooperative
East Kentucky Power Cooperative
Electric Cooperatives of Arkansas
Farmers Electric Cooperative
Flathead Electric Cooperative
Georgia Electric Membership Corporation
Golden Valley Electric Association
Great River Energy
Gunnison County Electric Association
Holy Cross Energy
Hoosier Energy
Intermountain Rural Electric Association
KAMO Electric Cooperative
Kauai Island Utility Cooperative (KIUC)
La Plata Electric Association
Lower Colorado River Authority
Lower Valley Energy
Midstate Electric Cooperative
Minnkota Power Cooperative
New-Mac Electric Cooperative
Orcas Power & Light
Oregon Trail Electric Cooperative
Palmetto Electric Cooperative
Park Electric Cooperative
Pedernales Electric Cooperative
Peninsula Light Company
PNGC Power
Prairie Power (formerly CCS/Soyland)
Southern Montana Electric G&T Cooperative
Tri-State Generation and Transmission Association
Vigilante Electric Cooperative
Wabash Valley Power Association
Western Farmers Electric Cooperative
Yampa Valley Electric Association
Federal

Municipal/Public Utilities

City of Alameda
American Municipal Power-Ohio
Anaheim Public Utilities
City of Ashland
Austin Energy
Austin Utilities (MN)
Benton County Public Utility District
City of Bowling Green
Braintree Electric Light Department
Burbank Water and Power
CPS Energy (San Antonio)
Cedar Falls Utilities
Central Minnesota Municipal Power Agency
Chelan County Public Utility District
Clallam County PUD
Clark Public Utilities
College Station Utilities (TX)
Colorado Springs Utilities
Columbia River PUD
Concord Municipal Light Plant
Cowlitz PUD
Edmond Electric
City of Eldridge (IA)
ElectriCities
Emerald People's Utility District
Estes Park Light and Power
Eugene Water & Electric Board
Fort Collins Utilities
Gainesville Regional Utilities
Grant County PUD
Grays Harbor PUD
Heartland Consumers Power District
Iowa Association of Municipal Utilities
Keys Energy Services
Lakeland Electric
Lansing Board of Water and Light
Lenox Municipal Utilities
Lewis County PUD
Lincoln Electric System
Lodi Utilities
Longmont Power & Communications
Los Alamos County (NM)
Los Angeles Department of Water and Power
Loveland Water & Power
Mason County PUD No. 3
Missouri Joint Municipal Electric Utility
Missouri River Energy Services
Moorhead Public Service
Muscatine Power and Water
City of Naperville
City of New Smyrna Beach
Northern Wasco County PUD
Oklahoma Municipal Power Authority
Omaha Public Power District
Owatonna Public Utilities
Pacific County PUD
City of Palo Alto Utilities
Pasadena Water & Power
Platte River Power Authority
Rochester Public Utilities (MN)
Roseville Electric
Sacramento Municipal Utility District
Salt River Project
San Francisco Public Utilities Commission
Santee Cooper
Seattle City Light

Consumer Protection

Federal Trade Commission
Green Pricing Accreditation
Low Impact Hydro Institute

Federal

Tennessee Valley Authority

Table D-2. Utility/Marketer Green Power Programs in Restructured Electricity Markets, 2008

Atlantic City Electric
Consumers Energy
Connecticut Light & Power
JP&L
Kennebunk Light and Power District
Long Island Power Authority
National Grid (Massachusetts Electric, Nantucket
Electric, Narragansett Electric, Niagara Mohawk)
NYSEG
Rochester Gas and Electric
Rockland Electric
PECO Energy
PSE&G
United Illuminating

Appendix E. Links to Utility Green Pricing Programs, and REC and Competitive-Market Green Power Offerings

Table of Utility Green Pricing Programs by State:
http://www.eere.energy.gov/greenpower/markets/pricing.shtml?page=1

Renewable Energy Certificate Retail Products:
http://www.eere.energy.gov/greenpower/markets/certificates.shtml?page=1

Retail Green Power Product Offerings in States with Retail Competition:
http://www.eere.energy.gov/greenpower/markets/marketing.shtml?page=1

Appendix F. Top Ten Utility Green Pricing Programs

Table F-1. Green Pricing Program Renewable Energy Sales (as of December 2008)

Rank	Utility	Resources Used	Sales (kWh/year)	Sales (aMW)[a]
1	Austin Energy	Wind, landfill gas	723,824,901	82.6
2	Portland General Electric [b]	Geothermal, wind	672,469,949	76.8
3	PacifiCorp [cde]	Wind, biomass, landfill gas, solar	492,892,222	56.3
4	Xcel Energy [ef]	Wind	362,040,082	41.3
5	Sacramento Municipal Utility District [e]	Wind, solar, biomass, landfill gas, hydro	325,275,628	37.1
6	Puget Sound Energy [e]	Wind, solar, biomass, landfill gas, hydro	291,166,600	33.2
7	Public Service Company of New Mexico	Wind	176,497,697	20.1
8	We Energies [e]	Wind, landfill gas, solar	176,242,630	20.1
9	National Grid [gh]	Biomass, wind, small hydro, solar	174,612,444	19.9
10	PECO [i]	Wind	173,375,000	19.8

a An "average megawatt" (aMW) is a measure of continuous capacity equivalent (i.e., operating at a 100% capacity factor).

b Marketed in partnership with Green Mountain Energy Company. For Portland General Electric, some products marketed in partnership with Green Mountain Energy Company.

c Includes Pacific Power and Rocky Mountain Power.

d Some Oregon products marketed in partnership with 3Degrees Group Inc.

e Product is *Green-e Energy* certified. For Xcel Energy, the Colorado and Minnesota Windsource products are *Green-e Energy* certified.

f Includes Northern States Power, Public Service Company of Colorado, and Southwestern Public Service.

g Includes Niagara Mohawk, Massachusetts Electric, Narragansett Electric, and Nantucket Electric.

h Marketed in partnership with Community Energy Inc., EnviroGen, Green Mountain Energy Company, Mass Energy, People's Power & Light, and Sterling Planet.

i Marketed in partnership with Community Energy Inc.

Table F-2. Total Number of Customer Participants (as of December 2008)

Rank	Utility	Program(s)	Participants
1	Xcel Energy [a]	*Windsource* [b] *Renewable Energy Trust*	71,571
2	Portland General Electric [cg]	*Clean Wind* *Green Source*	69,258
3	PacifiCorp [de]	*Blue Sky Block* [b] *Blue Sky Usage* [b] *Blue Sky Habitat*	67,252
4	Sacramento Municipal Utility District	*Greenergy* [b]	45,992
5	PECO [f]	*PECO WIND*	36,300
6	National Grid [hi]	*GreenUp*	23,668
7	Energy East (NYSEG/RGE) [f]	*Catch the Wind*	22,210
8	Puget Sound Energy	*Green Power Program* [b]	21,509
9	Los Angeles Department of Water & Power	*Green Power for* *a Green LA*	21,113
10	We Energies	*Energy for Tomorrow* [b]	19,615

a Includes Northern States Power, Public Service Company of Colorado, and Southwestern Public Service.

b Product is *Green-e Energy* certified. For Xcel Energy, the Colorado and Minnesota Windsource products are *Green-e Energy* certified.

c Some products marketed in partnership with Green Mountain Energy Company.

d Includes Pacific Power and Rocky Mountain Power.

e Some Oregon products marketed in partnership with 3Degrees Group Inc.

f Marketed in partnership with Community Energy Inc.

g Marketed in partnership with Green Mountain Energy Company.

h Includes Niagara Mohawk, Massachusetts Electric, Narragansett Electric, and Nantucket Electric.

i Marketed in partnership with Community Energy, EnviroGen, Green Mountain Energy Company, Mass Energy, People's Power & Light, and Sterling Planet.

**Table F-3. Customer Participation Rate
(as of December 2008)**

Rank	Utility	Customer Participation Rate	Program(s)	Program Start Year
1	City of Palo Alto Utilities [ab]	21.0%	*Palo Alto Green*	2003
2	Lenox Municipal Utilities [c]	10.5%	*Green City Energy*	2003
3	Portland General Electric [d]	9.7%	*Clean Wind* *Green Source* *Renewable Future*	2002
4	Madison Gas and Electric Company	9.6%	*Green Power Tomorrow*	1999
5	Silicon Valley Power [ab]	8.4%	*Santa Clara Green Power*	2004
6	Sacramento Municipal Utility District[b]	7.8%	*Greenergy*	1997
7	City of Naperville Public Utilities [e]	7.8%	*Renewable Energy Program*	2005
8	Pacific Power – (Oregon only) [ab]	6.2%	*Blue Sky Block* *Blue Sky Usage* *Blue Sky Habitat*	2002
9	River Falls Municipal Utilities [f]	5.3%	*Renewable Energy Program*	2001
10	Pacific Power [ab]	5.2%	*Blue Sky Block* *Blue Sky Usage* *Blue Sky Habitat*	2002

[a] Marketed in partnership with 3Degrees Group Inc.
[b] Product is *Green-e Energy* certified (www.green-e.org).
[c] Program offered in association with the Iowa Association of Municipal Utilities.
[d] Some products marketed in partnership with Green Mountain Energy Company.
[e] Marketed in partnership with Community Energy Inc.
[f] Power supplied by Wisconsin Public Power Inc.

Table F-4. Green Power Sales as a Percentage of Total Retail Electricity Sales (in kWh) (as of December 2008)

Rank	Utility	Program Name	% of Load
1	Edmond Electric [a]	*Pure & Simple*	6.4%
2	Austin Energy	*GreenChoice*	6.0%
3	River Falls Municipal Utilities [b]	*Renewable Energy Program*	5.8%
4	City of Palo Alto Utilities [ce]	*PaloAltoGreen*	5.7%
5	Portland General Electric [d]	*Clean Wind* *Green Source* *Renewable Future*	3.9%
6	Madison Gas and Electric Company	*Green Power Tomorrow*	3.8%
7	Pacific Power – (Oregon only) [ce]	*Blue Sky Usage* *Blue Sky Habitat*	3.3%
8	Sacramento Municipal Utility District [e]	*Greenergy*	3.0%
9	Fort Collins Utilities [e,f]	*Green Energy Program*	2.6%
10	Emerald People's Utility District	*EPUD Renewables*	2.2%

[a] Power supplied by Oklahoma Municipal Power Authority.
[b] Power supplied by Wisconsin Public Power Inc.
[c] Marketed in partnership with 3Degrees Group Inc.
[d] Marketed in partnership with Green Mountain Energy Company.
[e] Product is *Green-e Energy* certified (www.green-e.org).
[f] Power supplied by Platte River Power Authority

Table F-5. Price Premium Charged for New, Customer-Driven Renewable Power[a] (as of December 2008)

Rank	Utility	Resources Used	Premium (¢/kWh)
1	OG&E Electric Services [b]	Wind	-1.01
2	Edmond Electric [bc]	Wind	-0.94
3	Indianapolis Power and Light	Wind, landfill gas	0.07
4	Avista Utilities	Wind, landfill gas, biomass	0.33
5	Park Electric Cooperative	Wind	0.44
6	Austin Energy [be]	Wind, landfill gas	0.69
7	PacifiCorp [dg]	Wind, biomass, landfill gas, solar	0.78
8	Emerald People's Utility District	Wind	0.80
8	Basin Electric Power Cooperative [h]	Wind	0.80
8	Clallam County Public Utility District [b]	Landfill gas	0.80
10	Xcel Energy (Minnesota) [bdf]	Wind	0.91

[a] Includes only programs that have installed or announced firm plans to install or purchase power from 100% new renewable resources.
[b] Premium is variable; customers in these programs are exempt or otherwise protected from changes in utility fuel charges.
[c] Power supplied by Oklahoma Municipal Power Authority.
[d] Product is *Green-e Energy* certified (www.green-e.org).
e The price for new customers enrolling in the program (fifth batch of renewable energy capacity).
f Net premium of the Minnesota *Windsource* program.
g Pacific Power *Blue Sky Usage* and *Blue Sky Habitat* products; only available in Oregon. Product marketed in partnership with 3Degrees Group Inc.
h A number of Basin Electric Power Cooperatives offer green power at a premium of 0.8¢/kWh.

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13. **SUPPLEMENTARY NOTES**

14. **ABSTRACT** *(Maximum 200 Words)*
Voluntary consumer decisions to buy electricity supplied from renewable energy sources represent a powerful market support mechanism for renewable energy development. In the early 1990s, a small number of U.S. utilities began offering “green power” options to their customers. Since then, these products have become more prevalent, both from traditional utilities and from renewable energy marketers operating in states that have introduced competition into their retail electricity markets or offering renewable energy certificates (RECs) online. Today, more than half of all U.S. electricity customers have an option to purchase some type of green power product directly from a retail electricity provider, while all consumers have the option to purchase RECs. This report documents green power marketing activities and trends in the United States including utility green pricing programs offered in regulated electricity markets; green power marketing activity in competitive electricity markets, as well as green power sold to voluntary purchasers in the form of RECs; and renewable energy sold as greenhouse gas offsets in the United States. These sections are followed by a discussion of key market trends and issues. The final section offers conclusions and observations.

15. **SUBJECT TERMS**
NREL; Lori Bird; Claire Kreycik; Barry Friedman; renewable energy certificates; RECs; energy consumers; electricity; green power marketing; green pricing; renewable energy; electricity markets; utilities; greenhouse gas offsets

16. **SECURITY CLASSIFICATION OF:**			17. **LIMITATION OF ABSTRACT**	18. **NUMBER OF PAGES**	19a. **NAME OF RESPONSIBLE PERSON**
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Table Of Contents

INTRODUCTION

Carbon footprint, CO2 sequestration, greenhouse gas emissions. Consumers are getting used to hearing these technical and science-based terms from the mass media on a daily basis. Global warming is front and center, and customers are concerned.

Due to the explosion of media coverage of environmental issues, consumers are more educated and concerned about global warming and climate protection than ever before. Utilities are stepping up the plate, not only with fee-based green power programs (which still are not achieving stellar take rates, by any means), but also with other offerings aligned with customers' desires to be a part of the solution to these environmental woes.

Chartwell researchers are seeing utilities branch into renewable energy in different ways. We are seeing interest and growth in utility programs and services that help consumers feel good about the role they are playing in the environment, such as customer-owned renewable generation and "green" new home and commercial building programs.

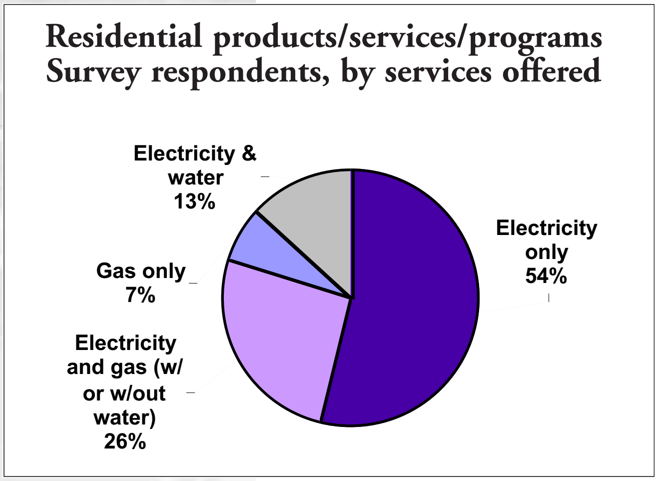
In addition, we predict greater growth in utilities' using renewables as an image-building tool rather than a product to sell. How are these efforts to communicate renewable energy in utilities' general portfolios affecting fee-based green power programs?

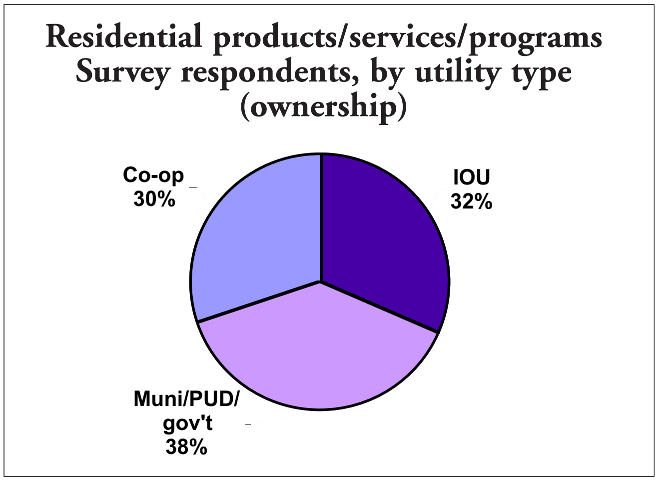
In any case, the big issue surrounding green or renewable energy is communication. Utilities are getting beat up by accusations that they have not done enough to install air-pollution equipment on older coal-fired plants that emit carbon dioxide and other greenhouse gasses. To counteract some of this "bad press," many utilities are working overtime to make stakeholders aware of their efforts to purchase or generate power from renewable sources. In many cases, utilities are replacing old feel-good messages with communications involving the technical and scientific terms with which consumers are becoming better acquainted.

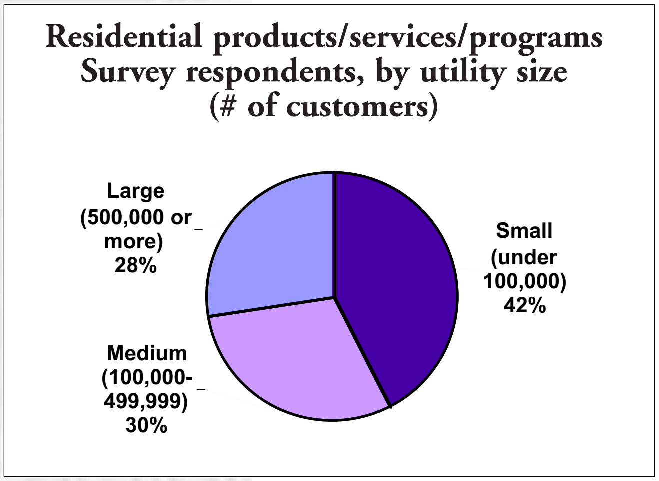
This report addresses utilities' responses to these hot-button issues. How are utilities stepping up to help their customers live a more eco-friendly lifestyle? Section I provides an analysis of the industry around this question.

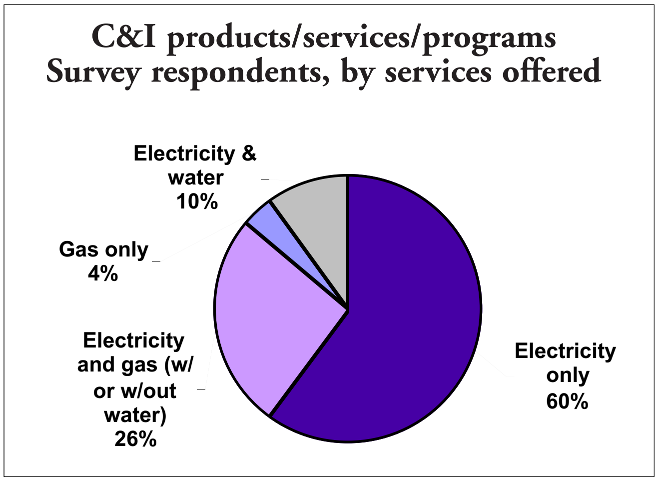
Much data in Section I is based on Chartwell's 2006 survey of utilities regarding their products/services/programs. In March and April 2006, Chartwell researchers surveyed via telephone and the Internet 76 utilities at random to gather data on energy companies' mass market products and services and 70 utilities at random to gather data on energy companies' products, services and programs aimed at C&I customers.

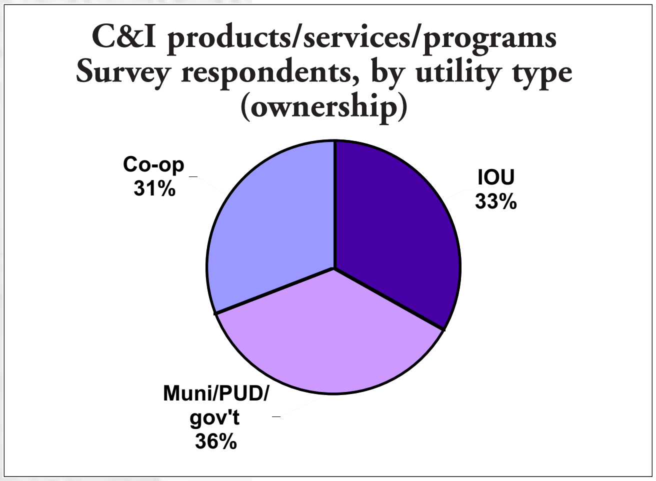
The characteristics of those utilities are provided on the next page.

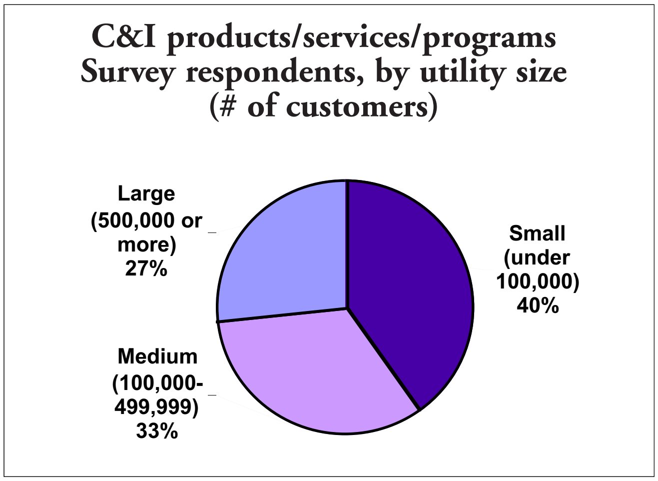












In addition, in Section II, we include 11 case studies on specific utility programs. The case studies examine fee-based green power programs, customer-sited generation programs and other utility efforts to help customers who want to “do the right thing” for the environment.

This publication is produced as part of The Chartwell Products, Services & Programs Research Series. The Series is a membership service that offers members a variety of topic reports such as this one; data summaries based on the residential and C&I products/services/programs utility surveys; a data summary and analysis of survey questions about marketing budgets and strategies; access to Chartwell research staff; input into research topics and survey instruments; vendor profiles; and databases of utility product and service offerings.

If you have any questions about the research, please contact the Senior Research Analyst and manager of the Research Series, Jennifer Quay Allen, at jallen@chartwellinc.com. For information on membership in the Series, please contact Bill Grist at bgrist@chartwellinc.com.

KEY POINTS

• Chartwell's 2006 survey regarding products/services/programs found that 58% of utilities offered green power as a premium product to residential customers; another 1% were in the planning stages and 12% said they were considering this product.

• Half the utilities surveyed offered green power as a premium product to C&I customers, with 1% in the planning stages and 17% considering this product offering.

• Although a high rate of utilities were considering a green power product, take rates are still low (about 1% on the residential side) and utilities are not viewing these programs as impactful.

• As a result, utilities are loudly heralding the addition of renewables to their standard power mix. Utilities are striving to turn these purchases (even if mandated) into good PR.

• The percentage of utilities purchasing renewable energy or renewable energy credits has risen from 37% in 2005 to 53% in 2006. This was the fastest growing area in Chartwell's 2006 utility products/services/programs survey.

• Due to an explosion of media coverage of environmental issues, consumers are more educated and concerned about issues such as global warming, carbon footprint, and climate protection. Utilities are fulfilling customers' desires to be a part of the solution by aligning their offerings with these hot-button issues.

• Utilities aid in customer-owned renewable generation and green building programs; and, although not addressed in this report, are beginning to focus on the environmental benefits of energy efficiency programs – a wise way to get more customers interested in saving energy.

• Thirty-two percent of utilities offered sales of or rebates on green technologies for residential customers, with another 13% planning or considering doing so. Twenty-six percent do so for C&I customers, with 12% planning or considering. Of the products/services/programs covered in the survey, this is under consideration by one of the largest proportions of utilities.

• In the 2006 survey, 39% of utilities said they offer an energy efficient new home construction program with 7% in the planning stages and another 7% considering such a program. About a quarter – 23% – of utilities Chartwell surveyed said they offer an energy efficient or green building program for new commercial construction. In addition, 10% are planning or considering a new commercial building program.

ANALYSIS

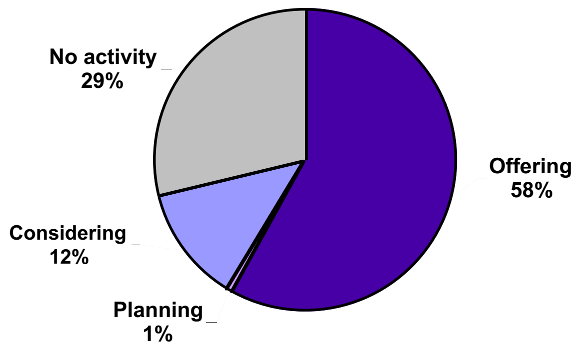
Chapter 1: Utility green pricing programs

Green energy has been a force within the utility industry for several years. Typically, consumers can participate in green energy programs by paying a small fee or premium on their bills; the money allows utilities (or other companies, if renewable energy credits are involved) to purchase or invest in the generation of green power.

It has become fairly commonplace for utilities to offer green power as a premium product to both residential and C&I customers. On Chartwell's 2006 survey of utilities regarding products/services/programs, 58% of respondents indicated they offer green power at a premium to residential customers; 1% were in the planning stages of doing so and another 12% were considering this product offering. Although 12% "considering" might indicate healthy continued growth in this area, Chartwell researchers are seeing utilities branch into renewable energy in different ways instead; we predict greater growth in utilities' using renewables as an image-building tool (rather than a product to sell). The utility industry also will see growth in other products or services that help consumers feel good about the role they are playing in the environment.

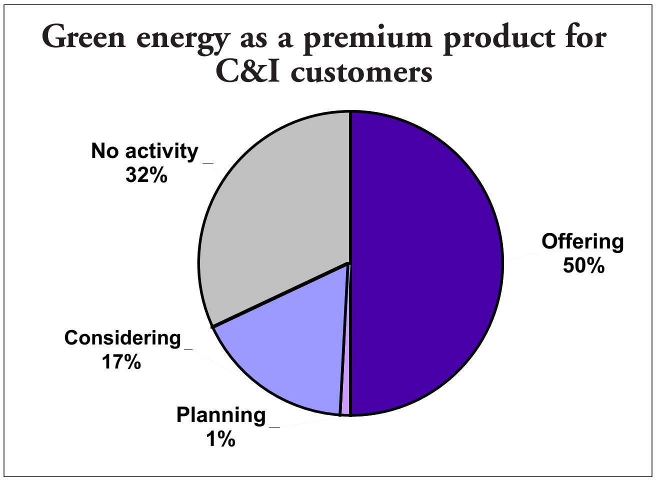
Government-owned utilities are most likely to offer green power to residential customers; 72% of them do, versus 54% of IOUs and 44% of cooperatives. Utility size doesn't play as much of a role, as 50% of utilities with fewer than 100,000 customers, 65% of utilities with 100,000 to 499,999 customers, and 62% of utilities with half a million or more customers offer green power at a premium.

Green energy as a premium product for residential customers



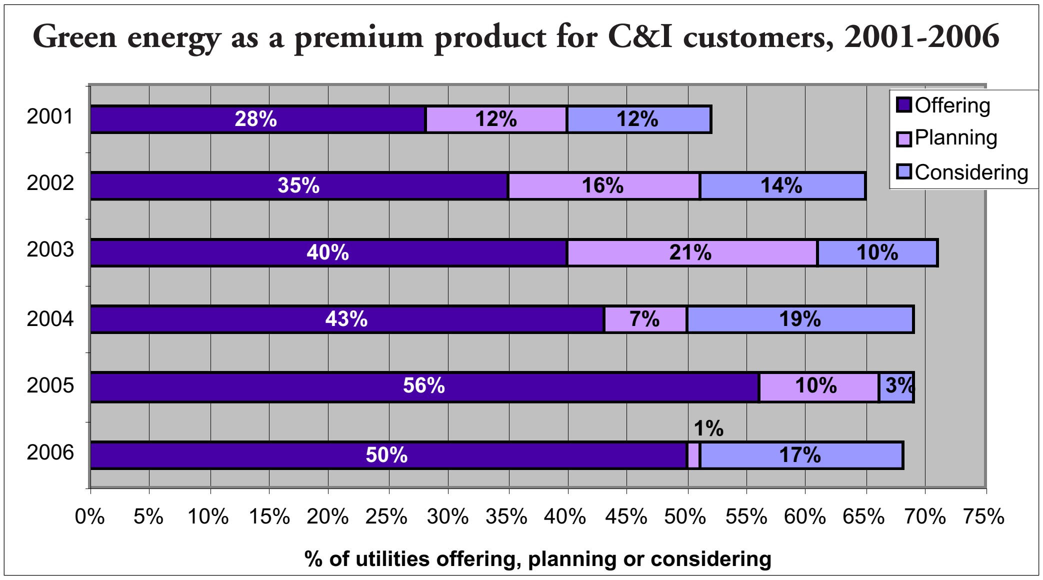
Half the utilities surveyed offer green power as a premium product to C&I customers, with 1% in the planning stages of doing so and another 17% considering this product. Chartwell researchers predict continued growth in this area. Not only are 17% of utilities considering adding green power to their product mix for C&I customers, but many of the utilities that already offer green power to residential customers may well add such an offering for large business customers.

Government-owned utilities are most likely to offer green power to C&I customers; 72% of them do, versus 44% of IOUs and 32% of cooperatives. Utility size also plays a role, with medium-sized utilities (100,000 to 499,999



customers) most likely to offer C&I customers green power; 78% of them do. Only 53% of large utilities (half a million or more customers) and 25% of small utilities (under 100,000 customers) offer C&I customers green power at a premium.

Comparing 2006 data to 2005 data shows that this product offering has remained rather flat. On the 2005 survey, 62% were offering, 5% in the planning stages and 4% considering green power at a premium to residential customers; and 56% were offering it to C&I customers, with 10% in the planning stages and 3% considering doing so. (Chartwell surveys different utilities, with some overlap, each year.)



Chartwell analysts believe this product offering has leveled off because of the disconnect between the customer (who is paying the fee) and the actual generation or use of green power. Customers are not convinced that paying a small fee every month for the utility to invest in green generation – in some cases several states away – is really doing much good. In addition, a large number of utilities already have added green power to their product mix. And finally, utilities considering such an offering are not seeing widespread success around the country as take rates are generally staying below 1%. As such, the growth rate of new utilities offering green power at a premium has slowed considerably.

As mentioned, take rates have remained flat at about 1%. Chartwell asked respondent utilities that were selling green power as a premium product how many residential customers were purchasing it. Dividing that number by the total number of customers, Chartwell determined that the utilities surveyed had achieved the following penetration or take rates with their green power product:

- 0.00%
- 0.00%
- 0.04%
- 0.09%
- 0.18%
- 0.19%
- 0.21%
- 0.29%
- 0.38%
- 0.46%
- 0.48%
- 0.50%
- 0.54%
- 0.59%
- 0.60%
- 0.63%
- 0.68%
- 0.70%
- 0.87%
- 0.93%
- 0.96%
- 0.98%
- 1.04%
- 1.06%
- 1.14%
- 1.38%
- 1.50%
- 1.50%
- 1.54%
- 1.60%
- 2.00%
- 2.18%
- 3.00%
- 3.33%
- 5.37%
- 16.33%

Not including the one highest and one lowest number, the average take rate among residential customers is 1.07% (which nearly matches last year's average take rate of 1.08%) and the median is 0.70%. Chartwell members can use the 2006 Products/Services/Programs Excel spreadsheet on Chartwell's Energy Library to see which utilities reported these take rates. The sortable spreadsheet also provides data on utility size, type and other product offerings.

Unfortunately, there's not a huge groundswell of support for green power from C&I customers either. Chartwell asked respondents with green power programs how many C&I customers participate. We received the following answers: Again, members can use the Excel database at www.energylibrary.com to see

- 0 (6 utilities)
- 3
- 4
- under 10 (2 utilities)
- 10
- 10 or so
- 14
- 16
- under 20
- 20
- 22
- under 25
- 29
- 33
- under 50
- 50
- 70
- 100
- 300
- 400 (2 utilities)
- under 1,000
- 1,400
- 40,000

which utilities (and their size, type, etc.) reported these numbers.

New twists on green programs

A handful of utilities last fall announced lower premiums for green energy, primarily because of the shrinking price gap between some green energy and standard electricity. Puget Sound Energy's green power add-on rates, for example, recently fell from 2 cents to 1.25 cents per kWh for residential and business customers, and from 1 cent to 0.6 cent per kWh for large-volume users (minimum of 83,333 kWh or $500 monthly). Minnkota Power Co-op cut its surcharge from 1.5 cents to 0.5 cent per kWh. Georgia Power lowered its rate before the program was even introduced to the public – from $5.50 to $4.50 per 100 kWh block. If this trend continues, more consumers might be willing to purchase green energy.

Wind power is by far the most often used by utilities in their green power programs. Of the 41 utilities offering residential customers green power at a

premium that provided details on the types of renewable sources they use (totals more than 100% because many utilities use more than one source):
- 30 (73%) use wind;
- 23 (56%) use biomass, methane gas, landfill gas, bio-gas;
- 19 (46%) use hydro or small hydro;
- 13 (32%) use solar/photovoltaics (PVs); and
- 1 (2%) uses geothermal.

While some utilities are only now launching green power at a premium, others that are "old hands" in this arena are adding new twists to attract customers to their programs. For example, under Portland General Electric's new Renewable Future option, not only is 100% of a participant's electricity use offset with wind power, but the participant's rate stays fixed until Dec. 31, 2011. The electricity price equals actual usage billed at a rate of $0.0908/kWh for higher-cost Earth-friendly power, about $14.38 more than the basic service rate per month for a typical customer using 910 kWh per month. Unlike the utility's Green Source and Clean Wind programs, which are charges *added* to a customer's current rate, Renewable Future *replaces* the customer's current rate.

FYI

Under Portland General Electric's new Renewable Future option, not only is 100% of a participant's electricity use offset with wind power, but the participant's rate stays fixed until Dec. 31, 2011.

The Los Angeles Department of Water & Power (LADWP) co-brands and cross-sells its many offerings under the Green LA banner with a single brand and phone number. "Customers call one number to talk about energy efficiency, the green power or solar programs, and any of the other programs we offer, such as our tree planting program," explains Gary Gero, director of energy efficiency and renewable solutions. This helps cross-market the premium green power program, he adds.

Other new strategies are being tested as well. A new program at Pacific Gas & Electric, for example, doesn't sell traditional green power. Instead, it allows business and residential customers to sign up to voluntarily pay a small amount on their monthly bill, based on energy usage, that will fund environmental projects "aimed at removing carbon dioxide from the air. The amount removed from the air will equal the amount of greenhouse gases associated with the customer's energy use, thus making them 'climate neutral,'" according to the company. The typical residential customer would pay $4.31, (or 3%) more each month. Premiums will be invested in California forest conservation and restoration projects that remove greenhouse gases from the atmosphere. PG&E anticipates that the program, dubbed ClimateSmart, will receive about $20 million in its first three years. Wanting to be the first to step up to the plate, the utility is committing more than $1 million of shareholder funding over the next three years to make energy use in the company's offices, service centers, maintenance facilities and other buildings completely climate neutral.

Similarly, Colchester, Vt.-based Green Mountain Power's new "choose2bgreen" program provides customers with "a way to neutralize their carbon footprint through renewable power and home heating and driving offsets." Choose2bgreen offers three different programs:
- Greener GMP – allows customer to purchase energy from certified renewable resources equal to some or all of their monthly use.
- CoolHome – provides customers with an option to offset their individual carbon footprint associated with heating their homes; $6 per month offsets six tons of carbon dioxide pollution per year.

- CoolDriver – provides customers with an option to offset their individual carbon footprint associated with driving their cars; the price – from $3 to $8 per month – depends on the size of car.

For in-depth information on specific utility programs, see the following case studies in Section II of this report:

- LADWP learns lessons, makes fixes to extensive Green Power for a Green LA program
- Silicon Valley reaching for 7.5% enrollment in 100% green program (originally published in February 2007)
- United Power customers reject green power (originally published in March 2006)
- We Energies business customers go green (originally published in February 2006)
- Rochester Public Utilities' lessons learned: Tie green power into brand, be more proactive, less reactive (originally published in December 2005)
- 'Energy happens' in CVPS Cow Power program (originally published in April 2005)
- OG&E wind program achieves 1.2% take rate in first year, moves to add 80 MW to wind farm (originally published in February 2005)

Chapter 2: Aiding in customer-owned renewable generation

There's a physical and psychological disconnect between the fee on the customer's bill and the generation of power from renewable sources in place of power from standard sources. Obviously, the customer paying the fee doesn't receive the green power directly; in many cases the green power is being generated many miles – if not many states – away. This fact makes some customers feel wary of the utility and helpless to make a difference in their own community.

There's a growing strategy for bridging the disconnect between the consumer and green power generation: Offer the customer the opportunity to generate his own electricity from renewable sources. In most cases, onsite or customer-owned renewable power generation involves solar power.

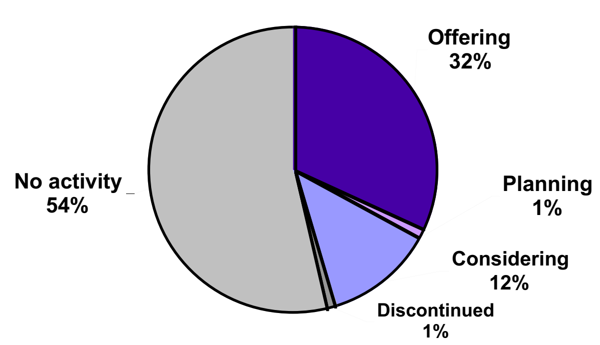
The government already offers a tax break on the purchase of solar systems. Utilities are stepping in to help by providing rebates, purchasing the environmental attributes from customer-generated solar energy, allowing for net metering and building general awareness of customer-generated renewable energy. Chartwell researchers predict the industry will see continued growth in this area.

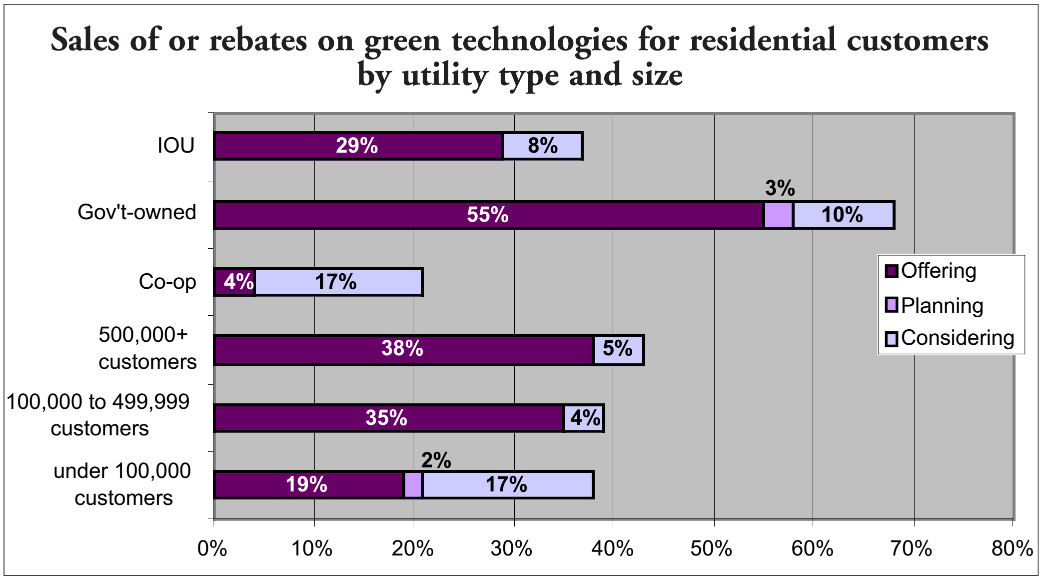
Almost unheard of a few years ago, in 2006, 32% of utilities reported on Chartwell's survey offering residential customers sales of or rebates on green technologies, with another 12% considering such an offering. Of the products/services covered in the Chartwell survey, one of the largest proportions of utilities is considering this offering.

The utilities offering sales of or rebates on green technologies describe them as:
- Rebates on PV (solar) panels – 14 utilities mentioned (2 are planning);
- Solar buyback/net metering – 5 utilities mentioned (1 is considering);
- Rebates on solar water heaters – 4 utilities mentioned;
- Sales of solar systems – 3 utilities mentioned (1 is considering);
- Financing for solar panels – 2 utilities mentioned; and
- Give away PVs to low-income customers (very limited) – 1 utility mentioned.

Again, government-owned utilities are most likely to offer such a program; 55% of them do, versus only 29% of IOUs and 4% of co-ops. Large utilities are slightly more likely to offer such a program than medium utilities – 38% versus 35%. Only 19% of small utilities offer sales of or rebates on green technologies for residential customers.

Sales of or rebates on green technologies for residential customers



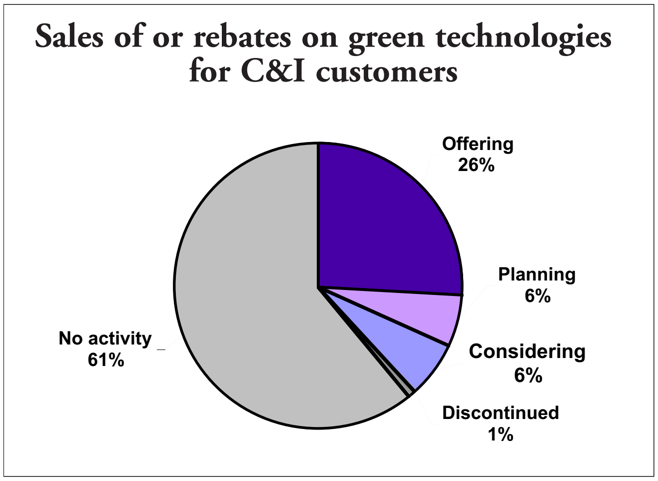


Similarly, for C&I customers, while distributed generation/onsite power has been around for years, the recent trend is toward providing incentives for them to generate their own energy using environmentally friendly technologies.

In 2006, 26% of utilities responding to Chartwell's survey sold or provided rebates on green energy technologies to allow their C&I customers to generate some of their own electricity using renewable sources such as the sun. Another 6% were in the planning stages of doing so and 6% were considering this product offering. Government-owned utilities are way ahead in this area: 56% of them offer sales of or rebates on green energy technologies, compared to only 9% of IOUs and 9% of co-ops. In looking at this offering by utility size, there is nearly no difference: 25% of small, 26% of medium and 26% of large utilities have this offering for C&I customers.

The utilities offering C&I customers sales of or rebates on green technologies describe them as:

- Rebates on solar technologies like PVs – 6 utilities;
- Buy-back or net-metering programs – 3 utilities;
- Sales of solar technologies – 2 utilities;
- School program that consists of PVs installation at schools – 2 utilities; and
- Rebates on ground source heat pumps – 1 utility.



Rebates on customer installations

Customers have flocked to various utilities to take advantage of rebates on photovoltaic installations, these utilities say. Some have had to close programs early with lengthy waiting lists. Others have provided more funding than originally allocated.

Solar is "by far" the most requested renewable installation at PG&E, for example, even though the program also provides rebates for wind turbines, fuel cells, microturbines and internal combustion engines. Most customers that Sara Birmingham, PG&E program manager, sees in the Self-Generation Incentive Program are commercial or industrial. The type of renewable energy source they choose depends on the company. "We have a lot of interest from a number of different companies and industries, including wineries. We have a lot of projects from cities, counties, public entities, educational facilities," Birmingham comments. "There are always internal champions within the different companies. It's fun working with them because it is their dream that they're implementing. Once they see those solar panels go up … they become internal champions within their communities."

"This relationship with a utility can dramatically improve solar market delivery and significantly accelerate closing the gap between solar and conventional energy costs. NSTAR has the ideal infrastructure to reduce the non-hardware portion of solar system costs."

Solar programs have proven to be popular at Xcel Energy as well, according to spokesman Tom Henley. Customers are lining up to take advantage of rebates through one of Xcel Energy's solar programs – Solar Rewards. This program has eclipsed the $7.7 million mark in payouts within a year after its March 2006 launch. Solar Rewards is designed primarily for residential or small commercial customers and pays rebates to those who have installed 0.5 kW to 10 kW systems any time after Dec. 1, 2005. Through an online application, Xcel Energy will rebate customers $2 per watt of solar panels installed on qualified customer premises. The state renewable portfolio standard calls for Xcel Energy to have 4% of its electricity come from solar (and half of that customer-sited generation; which comes to about 18 MW) by 2010. Currently about 2 MW of that 18 MW of solar generation are now established on the customer side.

In other cases, vendors are prompting utility programs. For example, NSTAR and Evergreen Solar Inc., a manufacturer of solar power products, have formed an alliance to increase the role of solar power in eastern Massachusetts. The alliance will promote cost-effective solar options for consumers. "This relationship with a utility can dramatically improve solar market delivery and significantly accelerate closing the gap between solar and conventional energy costs. NSTAR has the ideal infrastructure to reduce the non-hardware portion of solar system costs," said Richard M. Feldt, Evergreen Solar's president and CEO. The program will expand renewable energy choices for customers by making solar installations more accessible and affordable.

Sacramento Municipal Utility District (SMUD) is further smoothing the way for customer-owned renewable generation by no longer requiring the AC disconnect switch on most inverter-based solar systems for homes or businesses that have self-contained electric meters, which most do. In hopes of "increasing the number of systems installed in the utility's service area, SMUD took this action that can reduce the cost of solar systems by about $300," according to utility literature.

Other utilities help customers by subsidizing solar water-heating systems, which have a much lower initial cost than whole-home systems and thus may be more attractive to consumers. Jacksonville, Fla.-based JEA, for example, pays residential customers up to $800 and business customers up to 30% of the total cost up to $5,000 for purchasing and installing these systems. Florida also provides state rebates on solar water heaters.

Financing customer installations

Other utilities help make solar and other renewable generating systems more affordable to customers by providing low-cost financing. Ferry County PUD in rural Republic, Wash., for example, earned federal support for alternative energy solutions that can assist isolated, off-grid customers in the form of low-interest financing. With the backing of a USDA/Rural Utility Service (RUS) grant, Ferry County's new solar and line extension program for remote customers offers an alternative for area residents who have had no choice but to power their households with standby generators and other off-grid sources of power. The funds will be allocated for both line extensions and the purchase of solar photovoltaic systems.

In a nutshell, in early 2003, the RUS had announced the availability of $11.3 million in federal funds for high-energy-cost rural communities authorized under section 19 of the Rural Electrification Act of 1936. The grant funds were to be used "to acquire, construct, extend, upgrade, or otherwise improve energy generation, transmission, or distribution facilities serving communities in which the average residential expenditure for home energy exceeds 275% of the national average." The consumer's energy costs must be 23 cents/kWh or higher. John Friederichs – conservation director of Ferry County PUD – submitted a request for funds that would enable the utility to provide line extensions for those who qualify, or PV systems for those who don't. The plan sounded good to the RUS, and soon Ferry County PUD was looking at a grant award of $888,406. After nearly a year of administrative work, the first portion of the funds arrived in June 2004. These funds will enable qualified area residents to purchase line extensions or solar power under low-interest, long-term loans. "The idea that for $45 a month they could have all the power they ever dreamed of ... people are absolutely thrilled," Friederichs says. The basic solar system is going to cost around $18,000. It will be owned and installed by Ferry County PUD.

Paying customers for renewable energy credits

Another solar program at Xcel Energy, Renewable Energy Credit (REC), was closed after the utility received 653 applications and paid out 586. Under the program, Xcel Energy purchased RECs generated by customer systems for up to $2.50 per watt of power the facility is proposed to produce. "That is for the renewable energy credits, which are associated with that [level of] energy, and it's a one-time payment," reports Henley. Designed for solar power units from 0.5 kW to 10 kW, the REC payment was available to anyone within the state – Xcel Energy customer or not. With the rebate of $2 per watt discussed above and REC credit, customers with small installations can receive up to $4.50 per watt upfront.

FYI

Public Service of New Mexico (PNM) purchases the environmental attributes from customer-generated solar energy, and during a 12-year period that began in March 2006, expects to purchase the attributes from about 18.7 million kWh at a cost of 13 cents per kWh for a total of about $2.8 million. However, the utility estimated that generating the same amount of solar energy would require construction of a 1.2 MW solar facility that would occupy about five acres of land and cost about $7.8 million.

Similarly, Public Service of New Mexico (PNM) purchases the environmental attributes from customer-generated solar energy, and during a 12-year period that began in March 2006, expects to purchase the attributes from about 18.7 million kWh at a cost of 13 cents per kWh for a total of about $2.8 million. However, the utility estimated that generating the same amount of solar energy would require construction of a 1.2 MW solar facility that would occupy about five acres of land and cost about $7.8 million. The PNM program was immensely popular: within three months of the March 1, 2006, launch, the utility was more than halfway toward its first-year goal.

In a different kind of payment, under Puget Sound Energy's (PSE) new Renewable Energy Advantage Program (REAP), customers who generate their own electricity with solar, wind or anaerobic-digester systems can receive 15 to 54 cents from PSE for each kWh their systems generate up to a limit of $2,000 annually. The payments are in addition to PSE's solar system rebates and net-metering benefits. PSE's REAP program is the result of a recently implemented Washington law to provide financial incentives to encourage the in-state manufacture and installation of renewable energy systems. Customers who install renewable energy systems using components manufactured in Washington may boost their earnings to as much as 54 cents per kWh. To qualify for the program, customers need to have an interconnection agreement with PSE. Local governments, nonprofit organizations, school districts and businesses also are eligible for the program. Avista Utilities, also in Washington, has a similar program.

Net metering

Some utilities allow customers to send electricity generated from renewable sources to the electrical grid for a credit toward their energy costs. The utility subtracts the value of electricity the customer supplies to the grid from the value of what the customer takes from the grid. Customers pay the net difference between those two amounts.

In New York, customers who sell energy back to the utility receive a special rate or credit. "If, by the end of the year, their power generation has exceeded their use … we will issue that customer a check," notes Central Hudson spokesman John Maserjian. "Participating customers sell energy back to Central Hudson at both delivery and supply rates rather than just the supply rate." At this time, few customers actually produce excess power but nevertheless they are benefiting from having onsite renewable generation. "There are some customers who create excess power from time to time, but very few actually have a net generation by year end," Maserjian comments.

Working with customers in the program "has helped us learn what our customers are looking for in terms of energy production and green energy programs. Additionally it helps us gain experience with systems that are interconnected to our grid," Maserjian says. "We have learned that they're very interested in the environment and energy independence. They are more than willing to support renewable energy. Those who have the means are willing to make the investment."

> "For any new states that are coming on, I would encourage them to look at the whole portfolio of energy policies together, such as metering legislation, such as the renewable energy credits … as well as the rebates."

Developing a network of contractors has been vital to the net-metering program. The first step a customer takes in joining the program is to contact one of the installation contractors who are listed on the New York State Energy Research and Development Authority Web site or through a link on the Central Hudson site. "These contractors understand how the system works. They basically work directly with customers and help them obtain financing through the state. They also work with Central Hudson in submitting applications and arranging for system inspections," Maserjian explains. Through an expanded statewide network of installation contractors, and their use of standardized technology and services, the cost of solar technology is expected to eventually decrease, which is part of the overall goal, notes Maserjian.

In Canada, the Ontario Power Authority purchase electricity produced by small, customer-owned renewable energy projects such as wind, biomass or small hydroelectric at a base price of 11 cents per kWh. The fixed price for solar is 42 cents per kWh.

Under the PG&E program mentioned earlier, customers not only have their own source of renewable energy for a portion of their usage, they also may sell power back to the PG&E grid to earn credits that are applied to their future energy use. PG&E has interconnected almost 15,000 customer-owned solar-generating systems to the power grid – representing more than 110 MW and more than any other utility in the nation.

Birmingham's advice for other utilities interested in ramping up their solar programs is "to ensure that the statewide regulatory policy is consistent and try to look at the program as a whole. Because California was such an early adopter, it's been slightly fragmented as we looked at policies here and there. For any new states that are coming on, I would encourage them to look at the whole portfolio of energy policies together, such as metering legislation, such as the renewable energy credits … as well as the rebates. It's been a constantly evolving process in California." The foresight and timing of California's legislative and regulatory bodies have been the key to success in program implementation and customer uptake, she adds.

Interestingly, beginning in 2010, builders in California will be required to offer solar as a standard feature in new home developments of 50 or more. Currently, California has more than 23,000 PV system installations, of which 1,500 are installed on new homes. About 200,000 new homes are built in California each year.

For in-depth information on specific utility programs involving customer-owned renewable generation, see the following case studies in Section II of this report:

- Central Hudson: Standardized technology spurs growth of net metering program
- LADWP learns lessons, makes fixes to extensive Green Power for a Green LA program
- Xcel Energy: Customer-sited solar generation eclipses $7.7 million in payouts (originally published in March 2007)
- Solar installations soar at PG&E; utility hoping to see market transformation (originally published in June 2006)

Chapter 3: Residential and commercial green building programs

Energy efficiency is just starting to catch on in the mainstream media and within the minds of consumers as a "green" or environmentally friendly strategy. One of the first aspects of energy efficiency to be labeled "green" or environmentally friendly is new home/building construction, in part due to these homes' and buildings' emphasis on eco-friendliness such as the use of fewer chemicals in paints and carpets, more responsible construction practices, and water conservation.

Usually as part of a DSM program, utilities are stepping into the new home construction industry in several ways. In Chartwell's 2006 survey, 39% of utilities said they offer an energy efficient new home construction program. These programs will continue to grow at a healthy rate – 7% of utilities surveyed said they were in the planning stages of launching such a program while another 7% were considering a new home program to encourage green building practices in construction and greater energy efficiency in the final product.

Utility new home programs – many based on Energy Star – may include the following aspects:

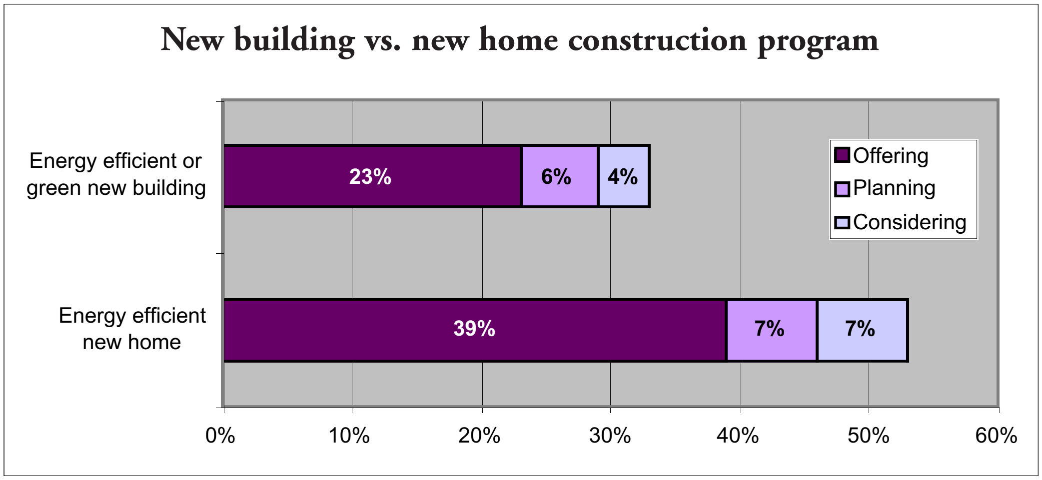
- educate builders, homeowners and realtors about energy efficiency and environmentally friendly building practices;
- provide financial incentives to help cover the extra up-front costs;
- provide third-party credibility through the inspection and certification of new energy efficient homes;
- publicize the energy efficient mortgage, which will help more potential homeowners qualify for higher financing; and
- help market energy efficient or "green" homes and the builders who build them.

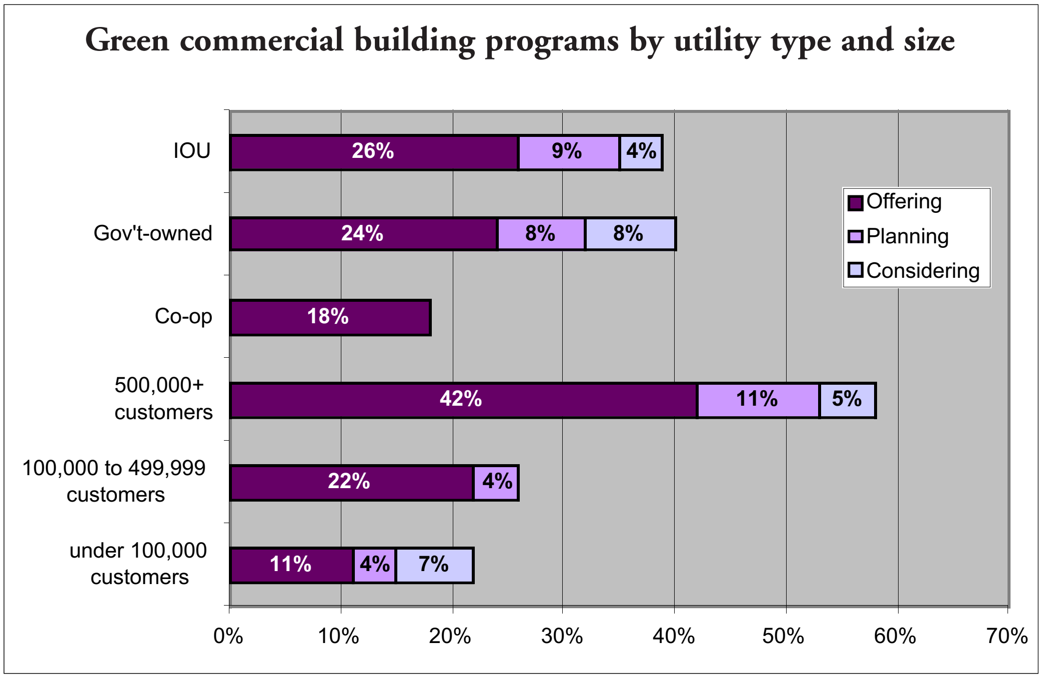
Of the utilities surveyed, TVA had the most success in energy efficient new home construction, having aided in the building of 7,200 energy efficient homes in 2005. Sacramento Municipal Utility District helped builders construct 5,500 energy efficient homes in 2005. In fact, government-owned utilities are most likely to have a new home construction program; 45% of them do, versus 33% of IOUs and 39% of cooperatives. Also, larger utilities are most likely to have these programs, as 34% of utilities with fewer than 100,000 customers, 39% of utilities with 100,000 to 499,999 customers, and 48% of utilities with half a million or more customers do.

Because buildings use from 33% to 48% of the energy consumed and 66% or more of all electricity in the United States and other developing countries – and because they produce about one-third of carbon dioxide and other emissions that harm air quality – governments, utilities, developers and tenants are looking at green commercial building as well. Kansas City, Houston, Atlanta, New Mexico, California, even Springfield, Mo. – all have either green buildings or a green building effort underway, according to Richard Morgan, manager of the green building program at Austin Energy, and other sources.

About a quarter – 23% – of utilities Chartwell surveyed said they offer an energy efficient or green building program for new commercial construction. In addition, 10% are planning or considering a new commercial building program.

Large utilities and IOUs are most likely to have a green building program in place. See graph below.





Chartwell found that utilities can and do help commercial builders by offering:

- computer modeling;
- design charrette coordination;
- assistance in obtaining LEED certification (LEED – the U.S. Green Building Council's Leadership in Energy & Environmental Design program – is a rating system that encourages sustainable, environmentally friendly, and energy and water efficient buildings);
- tax-credit assistance;
- green materials recommendations; and
- commissioning and life-cycle costing analysis.

As might be expected, utilities reported low numbers of buildings constructed under their programs in 2005 – ranging from zero for several new programs to 150 for NSTAR Electric & Gas in Boston.

Some utilities set the stage by setting the example. Exelon's new green headquarters, for example, is the largest office space in the world to be LEED-CI certified at the platinum level. "Exelon is addressing climate change by improving its own operations," according to company literature. "In 2005, Exelon established a voluntary goal to reduce greenhouse gas emissions by 8% from 2001 levels by the end of 2008, and this goal will be partially realized through the redesign of its company headquarters." Exelon consolidated its downtown Chicago locations and one suburban location to increase productivity and reduce long-term occupancy costs. To do so, Exelon chose to renovate existing space to LEED standards rather than building new. The project involved the design and construction of more than 220,000 square feet of office space on ten floors in an existing landmark building in downtown Chicago. In its new green headquarters, Exelon has reduced electricity consumption by more than 43% and water consumption by 30% compared to its previous space. Air quality was improved through the use of low-emitting materials, paints, carpeting, furniture and finishes, and the installation of high-density air filters. Exelon purchased more than 60% of the project and construction materials from manufacturers located within 500 miles to reduce emissions associated with transportation. Three-quarters of construction waste was recycled or salvaged, and almost one-third of furniture and other materials were reused to reduce waste. Exelon is also buying renewable energy certificates from regional wind power to offset 100% of electricity usage for the office space.

"Builders don't want to [build green] if there's not a market, so a lot of our job is marketing green homes and buildings to the public."

Similarly, Great River Energy's new 166,000-square-foot Maple Grove, Minn., headquarters will be the most energy-efficient office building ever constructed in Minnesota and one of the most energy-efficient in the world with LEED platinum-level certification. Features will include geothermal heating and cooling, solar heating and water heating, and an onsite wind turbine.

Interestingly, Great River Energy also created a new position: Director of Environmental Stewardship and Member Services. "Great River Energy has made the decision to act on the evidence that climate change is real by responding with energy resource solutions that support a sustainable environment," says Gary Connett, who filled the position. "My goal will be to ensure that environmental stewardship is the standard throughout our organization – to make sure that everything we do is judged by its impact on the environment. This can only be achieved in partnership with our member cooperatives and their customers."

Educating builders and the buying public is important

The most important task for the nation's oldest and largest energy efficient building program continues to be building trust, says Morgan of Austin Energy's program. "Building owners fear increased costs [with green building] with no payback," he explains. "You need to recognize their issues and meet their needs as you meet yours." Participating in trade associations of builders and developers "has really paid off for us over the years," he adds.

"Builders don't want to [build green] if there's not a market, so a lot of our job is marketing green homes and buildings to the public," he says. Austin Energy promotes a variety of green building benefits through the media, a special phone line, a Web site, speaking engagements and workshops for the public, which have been running quarterly for five years. "The workshops have been incredibly successful. They all sell out, and we get from 100 to 245 people at each event depending on the size of the venue," Morgan said.

FYI

Long Island Power Authority (LIPA) program leaders encourage towns in LIPA's territory to make voluntary Energy Star Homes criteria part of the standard building code. Several towns already have done so, with laws requiring homes built within their towns to meet New York Energy Star criteria. LIPA provides these towns with grants to help train inspectors to implement these laws.

Besides resistance to change, Morgan has run into other barriers as well. He has had to overcome lack of awareness, for example, by putting on professional seminars on topics such as living roofs and duct testing. He also makes special presentations "on their turf" and builds momentum by recognizing green builders. "We advertise their success; we recognize them in front of their peers," he says.

The road to transformation: from voluntary to code

In addition, Austin Energy partners with affordable housing to demonstrate the cost effectiveness of green building. Now the city requires that all affordable housing receiving public money meet green standards.

As a result, Austin has seen 7,000 single-family homes, 13,000 multifamily units and 12 million square feet of commercial space certified under the program. According to Morgan, this translates to 78 MW of peak demand reduction, 135,000 MWh of energy not consumed, and 40,000 tons of carbon dioxide not emitted.

Austin Energy works with the city to institute higher environmental or energy efficiency building standards every few years. "When we reach 22% to 25% of homes rated by our program, that's when we need to raise the bar on everyone," Morgan says. This strategy leads to permanent market transformation – lasting structural and behavioral changes in the marketplace.

Similarly, Long Island Power Authority (LIPA) program leaders encourage towns in LIPA's territory to make voluntary Energy Star Homes criteria part of the standard building code. Several towns – including Brookhaven Town, Babylon, Oyster Bay and Riverhead – already have done so, with laws requiring homes built within their towns to meet New York Energy Star criteria. LIPA provides these towns with grants to help train inspectors to implement these laws.

"The Energy Star resolution is changing how houses are built throughout the Island. That resolution changes Energy Star from a voluntary program in which less than 1% of new homes meet [standards], to a program which requires participation from all new construction. Energy Star, with its performance test, will ensure that new homes meet energy code requirements, conserve on the consumption of fossil fuels, reduce greenhouse gases, and make Brookhaven a more affordable place to live," says Brookhaven Town Supervisor Brian Foley. "Right here in Brookhaven Town, we need to find ways to cut energy costs and make home ownership more affordable for both our young people and our senior citizens. These Energy Star standards can save homeowners a great deal of money by cutting energy costs long-term, and that will help keep families in Brookhaven Town."

LIPA has been fostering the adoption of Energy Star Homes standards on Long Island as part of its Clean Energy Initiative, which is a 10-year, $355 million program designed to foster energy efficiency and the development and use of renewable alternative technologies such as solar, wind and geothermal.

Builders catching on

As the trend continues to catch on – in part thanks to utilities – builders are more attracted to eco-friendly building. The 2006 residential green building survey by McGraw-Hill Construction/National Association of Home Builders

FYI

The leading reason builders are considering green is that "it's the right thing to do."

Other prominent influences include lowering lifecycle costs, such as energy efficiencies and productivity increases; staying ahead of the competition or expanding business with customers who are interested in green building; and limiting exposure to liability on such issues as water leaks and mold. These are builders' hot buttons that utilities can address in their programs.

(NAHB) showed that 2005 saw a 20% increase in the number of home builders producing green, environmentally responsible homes. The study predicted that number would grow by another 30% in 2006.

"By 2010, the value of the residential green building marketplace is expected to boost its market share from $7.4 billion and 2% of housing starts [in 2005] to $19 billion-$38 billion and 5%-10% of residential construction activity," according to McGraw-Hill Construction.

In one example, Miami-based homebuilder Lennar recently announced that PV solar energy systems will become standard – just like carpet or cabinets – in more than 2,000 houses it plans to sell in the Sacramento and San Francisco Bay areas over the next few years. According to a March 13, 2007, article in The Atlanta Journal-Constitution, "buyers, sold on the promise that solar electric systems and other energy-efficient features will cut their monthly power bills by as much as 60%, are snapping up the houses. … While Lennar and other homebuilders are struggling elsewhere, Lennar's solar [home] sales are soaring. The company said it sold 31 of the first 39 [solar homes] … in the first three months. … The houses cost about the same as many similar-sized new houses nearby without solar equipment."

The McGraw Hill/NAHB survey reveals that the leading reason builders are considering green is that "it's the right thing to do," an indication of the industry's strong links to the community, says Harvey Bernstein, vice president of Industry Analytics and Alliances for McGraw-Hill Construction. Other prominent influences include lowering lifecycle costs, such as energy efficiencies and productivity increases; staying ahead of the competition or expanding business with customers who are interested in green building; and limiting exposure to liability on such issues as water leaks and mold. These are builders' hot buttons that utilities can address in their programs.

Obstacles remain, the survey showed. Starting costs and the lack of interest by consumers to pay additional costs for a green home are perceived as a barrier by 82% and 79% of builder firms surveyed, respectively. Also rated as important were the following: educating the marketplace on green building concepts, and revising codes, ordinances and regulations. Again, these are areas in which utilities can step up to help builders overcome resistance.

Corporations catching on

Another issue utilities can build on is companies' desires to burnish their image as corporate citizens. According to *Investor's Business Daily*, Wal-Mart, Johnson & Johnson, Boston Scientific, Pfizer and Wells Fargo & Co. are just a few of the companies building facilities that aim to meet LEED standards. From midtown Manhattan's new 46-story Hearst Corp. building to the three-story Liberty Property Trust building in Scottsdale, Ariz., green building helps companies come across as good stewards of the environment. In addition, "some investors are pushing companies to marry environmental stewardship with financial results," according to *Investor's Business Daily*. "Shareholder resolutions for improving energy efficiency and reducing greenhouse gases jumped from six in 2001 to 20 the following year" and 33 last year.

Ameren was able to benefit from the attention several corporations in its service area had already received for green building. A highly visible LEED building complete with a wind turbine had put green building front and center in St. Louis. The Alberici Group headquarters and 30 other green building projects in the works had contributed to general excitement in the region around green building, according to Cindy Bambini, project engineer at St. Louis-based Ameren. This environment may have contributed to the success of AmerenUE's new green building program.

As part of an energy efficiency collaborative, the utility funded a $400,000 LEED Incentive Grant Program. AmerenUE's program awarded grants in two parts – $5,000 up front and the balance, based on the number of LEED points received, upon certification: $25,000 for Platinum; $20,000 for Gold; $15,000 for Silver; and $10,000 for Certified. The grants are to be applied to soft or administrative costs, Bambini explains, such as the certification fee, LEED documentation, energy modeling or analysis. The Ameren program also provides for sponsorship of six LEED training courses and scholarship funds allowing students to attend the courses.

The utility received 18 submissions during the seven-month application period. Original funding of $120,000 wouldn't cover all the projects, which all seemed worthy, Bambini says, so her group went back for and was granted more funding. Grant awards went to a mixture of project types, for example, low-income housing, mixed-use residential, a science wing addition for a private high school, a restaurant and a medical building.

Ameren held a reception to honor the recipients and award the up-front grant payments. "Two TV stations were there; we got great press coverage," Bambini told the audience. The program was also documented in the local newspapers. "We will attend the ribbon cutting ceremonies at all 18 buildings," she continued, adding that not only is Ameren hoping for ongoing media coverage but that it's important for the utility to stay connected with these building developers and owners.

Chapter 4: Renewables in the standard mix

Utilities' energy resource plans call for greater emphasis on conservation and more renewable energy resources. For example, like many utilities, KCP&L's proposal to meet growing demand includes not only a new power plant, but also demand response, energy efficiency and a new 100.5 MW wind energy facility.

Hardly a day goes by during which a North American utility doesn't announce new plans to generate or purchase energy made from renewable sources such as sunlight, wind, ocean waves, geothermal energy or even cow manure. Many utilities issue RFPs for renewable power purchases or purchase green credits. Others, like Oklahoma Gas & Electric, prefer ownership. After getting its toes wet with a purchase of 50 MW of wind power, the utility's next step was to become the proud owner of a 120 MW wind farm developed by Invenergy Wind LLC.

Utilities take a wide variety of approaches to fulfilling state mandates and/or adding renewable energy to the mix for other reasons. Here are just a few diverse examples:

- Ameren is piloting a project that converts hog manure gas to electricity.
- Atlantic County Utility Authority installed two 1,600+ kW methane-to-electric power generation systems at its landfill in Egg Harbor Township, N.J.
- MidAmerican Energy owns a huge number of wind energy installations and plans to build more.
- LADWP plans to purchase 438,000 MWh of renewable energy annually from several small hydro-electric generating facilities.
- Minnesota Power is nearing completion of a biomass energy initiative.
- San Diego Gas & Electric plans to purchase solar energy from what will be one of the largest solar facilities in the world.
- Illinois Rural Electric Co-op (DOE's Wind Cooperative of the Year) has a 1.65 MW wind project.

Green energy auctions help utilities meet state standards

It's no e-bay, but green energy or RECs can be purchased through online auctions. World Energy, for example, runs online green power auctions for utilities that provide "a transparent marketplace, with over 200 suppliers in the system," says Richard Donaleski, World Energy CEO. "The way it works now, with [utilities turning to] brokers or third-parties [to make green power or REC purchases], the process is very opaque. We go directly to the same project developers," he says. Purchasers know exactly how much they're paying for the energy and what the flat fee to World Energy will be, he explains. Minella Gjoka, director of World Energy's green division, claims that a recent online auction saved a green power purchaser $42 million. "The process is so transparent that even the local [public utility commission] logged on and monitored it. Traditionally, utilities have to research and find their own supplies [or use a broker]. It's difficult for them to determine what they should pay for green energy or RECs."

With new state renewable portfolio standards, "we do see pressure as demand is going up," Donaleski says. "There are not enough projects out there right now" to fulfill all the requirements under state standards. As such, the price of green energy is being pushed up, he adds. "Utilities really want clarity on state requirements so they can look at long-term solutions. Uncertainty makes it difficult." World Energy also builds financial models for utilities to look at buying the output from a proposed project or own a project outright.

- PECO is looking at purchasing and banking 240 MW of alternative energy credits for five years.
- KCP&L, as part of a "balanced approach to power generation," owns and operates a wind farm.
- Southern California Edison, the nation's leader in renewable power delivery, has a portfolio that includes 1,021 MW from wind, 892 MW from geothermal, 354 MW from solar, 226 MW from biomass and 95 MW from small hydro.
- Arizona Public Service's Saguaro Solar Power Plant in Redrock, Ariz., recently featured on ABC's 20/20, is the first facility that uses solar-trough technology built in the U.S. in almost 20 years. Last year, Power Magazine named the facility one of the top 12 power plants in the world.

The list of utilities – large and small; munis, co-ops and IOUs; rural and urban; in all areas of North America – that are announcing RFPs or new purchases/projects in the area of renewable energy continues to grow. None of these utilities seem to have all their eggs in one basket; the majority of them have conducted or are planning a variety of renewable energy projects or purchases. It's not always easy: Issues KCP&L had to consider in choosing its wind farm's Spearville, Kan., location included native prairie landscapes, wetlands, other critical wildlife habitats, major migratory bird concentrations or thoroughfare areas, grassland bird nesting areas, and scenic resources.

State renewable portfolio standards and other government regulation/legislation

Of course, many of these utilities must begin working toward state renewable portfolio standards (RPS). According to the Department of Energy (DOE), "a renewable portfolio standard is a state policy that requires electricity providers to obtain a minimum percentage of their power from renewable energy resources by a certain date." Currently, 21 states and the District of Columbia have RPSs in place. Together these states account for more than 42% of the electricity sales in the United States, according to the DOE. Two other states, Illinois and Vermont, have nonbinding goals for adoption of renewable energy instead of an RPS. According to North Carolina State University's Database of State Incentives for Renewables and Energy Efficiency, the following are each state's general requirements.

- Arizona – 15% by 2025. Technology minimum: 30% of the standard must be derived from distributed renewable energy (4.5% of total electricity sales by regulated utilities). Credit trading: Yes. (Subject to final approval by the Office of the Arizona Attorney General.)

- California – Increase 2% per year beginning in 2003 to reach at least 20% by end of 2010; goal of 33% by end of 2020. (Currently under review by the California Public Utilities Commission, the California Energy Commission, and the California Legislature.)

- Colorado – Investor-owned utilities: 20% by 2020. Electric cooperatives: 10% by 2020. Municipal utilities serving more than 40,000 customers: 10% by 2020. Technology minimum (IOUs): 4% of RPS requirement from solar-electric generation technologies; half of solar requirement must be located onsite at customers' facilities.

- Connecticut – 10% by 2010. Technology minimum: A minimum percentage each year must come from “Class I” renewables, which exclude certain biomass, biogas and hydro facilities.

- District of Columbia – 11% by 2022. Technology minimum: 0.386% solar by 2022. Credit trading: Yes.

- Delaware – 10% by 2019. Credit trading: Yes.

- Hawaii – 20% by 2020.

- Iowa – The state’s two investor-owned utilities, MidAmerican Energy and Interstate Power and Light, must contract for a combined total of 105 MW of their generation from renewable-energy resources, including small hydropower facilities. The 105 MW is allocated between the two utilities based on their Iowa retail peak demand.

- Illinois – 8% in 2013. Technology minimum: 75% wind.
(This is a goal, not a standard.)

- Massachusetts – 1% new renewables in 2003, increasing to 4% in 2009 (plus 1% each year after 2009). Credit trading: Yes.

- Maryland – Tier 1: 9.5% in 2022 and beyond; Tier 2: 2.5% in 2006 through 2018. Technology minimum: 2% solar electric in 2022 as part of the Tier 1 requirement. Suppliers also receive 110% - 120% credit for wind and 110% credit for methane during a specified timeframe. Credit trading: Yes.

- Maine – 30% by 2017. There also is a separate goal to increase the share of new renewables 10% by 2017. Credit trading: Yes (through NEPOOL Generation Information Systems).

- Minnesota – 25% by 2020.

- Montana – 15% by 2015.

- New Jersey – 22.5% by 2021. Technology minimum: 2.12% of retail electricity supply must be generated using solar by 2021 (approximately 1,500 MW solar). Credit trading: Yes.

- New Mexico – IOUs: 5% by 2006, rising to 10% by 2011, 15% by 2015, and 20% by 2020. Rural electric cooperatives: 5% by 2015, rising to 10% by 2020. Credit trading: Yes.

- Nevada – 20% by 2015. Technology minimum: 5% of the energy portfolio must be solar. Credit trading: Yes.

- New York – 24% by 2013. Technology minimum: 2% of total incremental RPS requirement (7.71%) is set-aside for the customer-sited tier, for a total of 0.1542% of customer-sited generation.

- Pennsylvania – 18% during compliance year 2020-2021. Technology minimum: solar PV set-aside of 0.5% by May 31, 2021. Credit trading: Yes.

- Rhode Island – 16% by 2020. Credit trading: Yes.

- Texas – 5,880 MW by Jan. 1, 2015. Technology minimum: Target of at least 500 MW from renewables other than wind. Credit trading: Yes.

- Vermont – Total incremental energy growth between 2005 and 2012 to be met with new renewables (10% cap). Credit trading: Yes. (This is a goal, not a standard.)

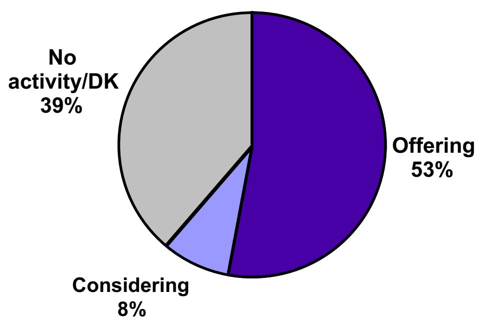
- Washington – 15% by 2020.

- Wisconsin – Requirement varies by utility; for the year 2015, each utility must increase its renewable-energy percentage by at least six points above the utility's average renewable-energy percentage for 2001, 2002 and 2003, with a statewide goal of 10% by Dec. 31, 2015. Credit trading: Yes.

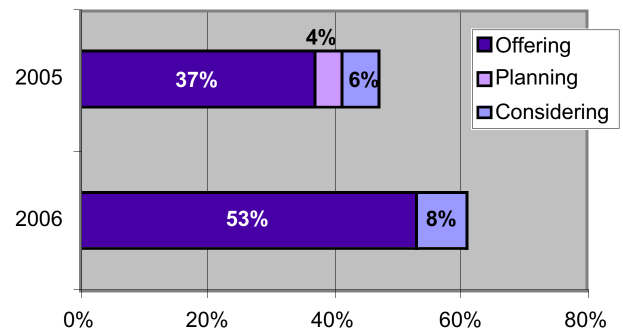
Chartwell survey reveals 16 percentage points growth

In 2006, 53% of utilities have energy generated from renewable sources as part of their regular fuel mix. This shows extraordinary growth of 16 percentage points from 37% reporting such on Chartwell's 2005 survey.

Green energy as part of regular fuel mix (not sold at a premium)



Green energy as part of fuel mix (not sold at a premium), 2006 vs. 2005



Government-owned utilities are most likely to have renewable sources in their standard generation mix; 62% of them do, versus 54% of IOUs and 39% of cooperatives. Utility size doesn't play as much of a role, as 50% of utilities with fewer than 100,000 customers, 57% of utilities with 100,000 to 499,999 customers, and 52% of utilities with half a million or more customers have renewable sources in their standard generation mix.

We asked utility respondents what percentage of their portfolio is made up of renewable energy. Using only the responses that were real numbers (i.e., not using answers such as "under 5%" because this number isn't exact), the average amount – with two utilities that reported 80% and 100% of their portfolio consists of renewable energy – is 13.65%. Without these two utilities, the average is 6.38%. The answers provided were:

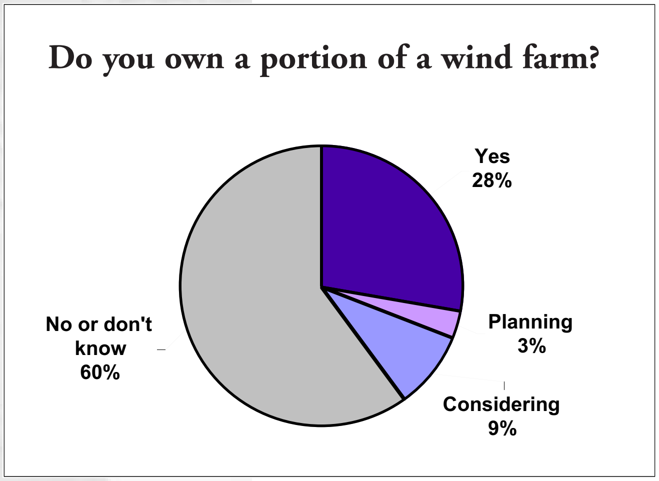
- 0.5%
- "under 1%" (9 respondents)
- 1%
- 1.83%
- 2% (2 respondents)
- 2.24%
- 2.5%
- 4% (2 respondents)
- "under 5%" (4 respondents)
- 5% (2 respondents)

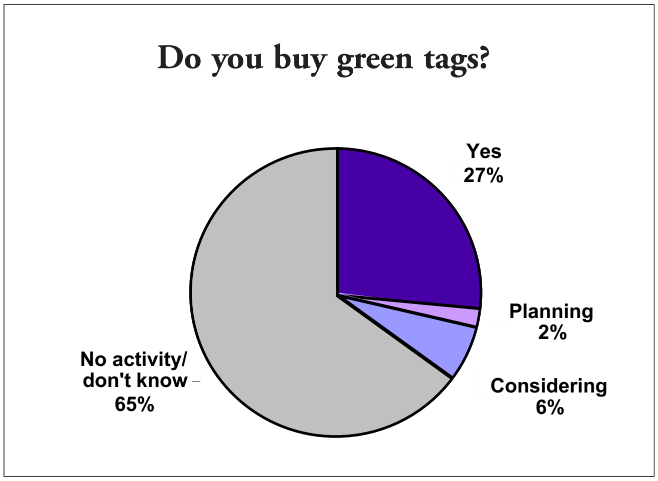
- 6%
- 7%
- "under 10%"
- 10% (3 respondents)
- 11%
- 13%
- 15%
- 20%
- 80%
- "over 90%"
- 100%

Of the 39 utilities using renewable sources as part of their regular fuel mix that provided details on the types of renewable sources they use (totals more than 100% because some utilities use more than one source):
- 23 (59%) use hydro or small hydro
- 19 (49%) use wind
- 19 (49%) use biomass, methane gas, landfill gas, bio-gas
- 10 (26%) use solar/PVs
- 1 (3%) use geothermal

In addition, 28% of all utilities surveyed own a portion of a wind farm. (All but three of these 18 utilities have a fee-based green power program in place.) Another 3% are the planning stages and 9% are considering becoming partial or full owners of a wind farm.

Similarly, 27% of utilities surveyed buy green tags. (All but three of these 17 utilities have a fee-based green power program in place.) Another 2% are in the planning stages and 6% considering purchasing green tags.





Chapter 5: Generating customer awareness

The big issue surrounding green or renewable energy these days is communication. Utilities are getting beat up by accusations that they have not done enough to install air-pollution equipment on older coal-fired plants that emit carbon dioxide and other greenhouse gases. To counteract some of this "bad press," many utilities are working overtime to make stakeholders aware of their efforts to purchase or generate power from renewable sources. Communications and marketing staff should be brought in on the front end to generate customer awareness and make the most of the goodwill that can be generated from doing so.

New buzzwords

As consumers are becoming more educated by the mainstream media's intense focus on the science behind environmental issues, savvy utilities are keeping up with the times and moving beyond messages revolving around simply "the environment," being "green" or "save the planet."

Instead, these utilities are hitting consumers with the same messages they're seeing emphasized in the general media, such as:

Global climate change/climate protection

- MidAmerican Energy addresses "global climate change" in its press materials.
- "To combat climate change and rising wholesale energy costs," Puget Sound Energy (PSE) is not only acquiring more renewable energy but also is putting more resources into helping its customers conserve electricity and natural gas.
- In announcing more renewable energy options for customers who want to "take action through their energy use," Madison Gas & Electric's news release headline reads, "MGE customers offered program to address global climate change."

Greenhouse gas emissions

- New Jersey Resources says it plans to "reduce greenhouse gas emissions and help curb the effects of global warming." In a press release, the chairman and CEO said "we are committing ourselves to reducing and offsetting our own emissions 20% by 2020."
- PSE has joined the Chicago Climate Exchange (CCX) – a voluntary, legally binding greenhouse gas emissions reduction, registry and trading program. "PSE joins other [organizations] that, in becoming CCX members, agree to reduce emissions of greenhouse gases, believed to be a major contributor to global warming," according to the utility's materials.
- Similarly, San Diego Gas & Electric Co. has successfully certified its 2005 greenhouse gas emissions inventory with the California Climate Action Registry, earning the status of "Climate Action Leader."
- Pacific Gas & Electric has launched ClimateSmart, "a new voluntary climate protection program that allows customers to reduce greenhouse gas emissions associated with their energy use by investing in projects that eliminate or capture carbon dioxide emissions."
- We Energies tells customers its green power program "decreases use of power plants fueled by coal and natural gas, reducing greenhouse gas emissions."

Sulfur dioxide/carbon dioxide

- Tucson Electric Power touted its methane plant as reducing fossil fuel emissions and reducing sulfur dioxide emissions by more than 870 tons while avoiding the production of more than 145,000 tons of carbon dioxide.
- MidAmerican Energy talks of “transitioning to a low-carbon economy.”
- FPL Energy says its wind projects in Texas “offset fossil-fueled power generation emissions totaling more than 2.3 million tons of carbon dioxide, more than 5,000 tons of sulfur dioxide and over 2,000 tons of nitrogen oxide that would have otherwise been released in the atmosphere if not for the wind farms.”
- San Diego Gas & Electric has this to say about a new solar installation: “This contribution of clean solar energy will prevent the release of approximately 60 tons of carbon dioxide into the atmosphere each year. Scientists are now convinced that carbon dioxide is one of the primary agents contributing to global warming.”
- KCP&L says it has agreed on a set of initiatives to “offset carbon dioxide and reduce other emissions.” KCP&L plans to “pursue offsets for all of the global warming emissions associated with its new plant.”
- Since 2002, according to Portland General Electric, its renewable power customers have “avoided release of an estimated 648 million pounds of carbon dioxide at conventional power plants, which is like taking 56,665 cars off the road. Man-made carbon dioxide is one of the causes of global warming.”

FYI

Colchester, Vt.-based Green Mountain Power’s new “choose2bgreen” program provides customers with “a way to neutralize their carbon footprint through renewable power and home heating and driving offsets.”

Carbon footprint/carbon-neutral

- “Carbon footprint” is a calculation of carbon dioxide emissions including direct sources such as transportation and energy use and indirect sources like air travel and paper usage. Several utilities have begun using this phrase in customer and media communications.
- The chairman and CEO of New Jersey Resources discussed the “fight against climate change” and said in a press release, “We have outlined an agenda to take the appropriate steps to reduce and offset our carbon footprint and will invest over $1 million in the next five years to meet this goal.”
- Under PG&E’s Climate Smart program, PG&E will calculate customers’ “climate footprint” based on their energy use.
- Colchester, Vt.-based Green Mountain Power’s new “choose2bgreen” program provides customers with “a way to neutralize their carbon footprint through renewable power and home heating and driving offsets.”

Sustainability

- At Arizona Public Service, the message centers on a sustainable future. “A sustainable future at APS includes solutions that enable the company and its customers to better utilize renewable energy resources and use less energy.” The company also speaks of its “efforts to support environmental health.”

Other messages

Two other important messages that go beyond the traditional “feel good” include:

Cost-effectiveness of renewable sources of energy

- “Renewable, non-emitting sources of energy are a growing part of our energy mix. These sources can provide cost-effective energy to our customers and help hedge against more volatile fuel prices,” Xcel Energy boasts.
- At Austin Energy, “We sign a 10-year contract for the annual output of a certain number of wind-turbines and pass that decade-long fixed cost on to our customers as a hedge against increasingly volatile fossil fuel prices,” says

Michael McCluskey, senior vice president for wholesale and retail markets. "We do this by replacing the fuel charge on the bill of a GreenChoice subscriber with a 'green power charge' that is reflective of the wind contract costs. This means that unless Austin Energy base electric rates increase, which has not occurred since 1994, the customer knows exactly what they will be paying for power for 10 years."

Economic development

- "Puget Sound Energy built 18 miles of roads to service the towers [at a new wind farm]. Eighteen workers will staff the Hopkins Ridge project and PSE's local office in Dayton," the utility announced.
- Besides their environmental impact, FPL Energy says its wind projects in Texas provide "new economic opportunities for local communities and the state. In 2006, these 11 wind projects provided a significant direct and indirect economic impact to Texas generating tens of millions of dollars in the form of state and local tax payments, salaries, lease payments and locally purchased goods and services, all helping to revitalize rural communities through the state."
- Nebraska Public Power District says, "Continued participation in wind development projects not only complements NPPD's support for energizing Nebraska's rural economy, it fits our goal to provide power through a diverse mix of generation resources and remain responsible environmental stewards."

These are but a few examples of the new types of messages many utilities are using.

Many others are still using traditional, feel-good messages such as:

- "preserving and protecting the environment;"
- "the same as planting X number of trees or not driving X number of miles;"
- "protecting the environment for future generations;"
- "a clean and healthy environment for future generations;" and
- "make a difference in the environment."

A communications conundrum: Distinguishing between green power (at a premium) and green power (in the mix)

As mentioned above, many of these utilities must begin working toward state renewable portfolio standards. At the same time, in these days of increased scrutiny, utilities want to use their purchases or generation of clean energy to improve their image. After all, image goes a long way in customer satisfaction, employee satisfaction, stock price and other important measures. As such, utilities may find it more effective to tout their purchase or generation of green power using renewable sources as part of their regular fuel mix than to offer green energy as part of a special premium program.

For example, although the premium green power program at Los Angeles Department of Water & Power (LADWP) has experienced some success (along with some growing pains), some confusion has arisen over just what it means to be a green power customer, especially since the utility board adopted an ambitious renewable portfolio standard – 20% renewable by 2010. "That has led to a little bit of confusion among our customers, who wonder what it is they're signing up for," explains Gary Gero, director of energy efficiency and renewable solutions. “We’re going to be starting a re-launch of the [premium] program and perhaps do a little re-branding … just to make sure there’s a distinction in the customer’s mind between what our program offers in addition to what the department is doing for all customers.”

Similarly, one factor in United Power’s green power program’s low participation rate, says Heidi Storz, marketing and communication coordinator, may be the amount of renewable hydropower, up to 28%, that is already offered through Tri State, United Power’s generation and transmission cooperative, and the Western Area Power Administration. This has provided a challenge in attracting green power customers, she says. “The message is that people want to do the right thing; they just don’t know how to get there.”

Some utilities, though, say customers are still asking for premium green power programs. In one example, although Silicon Valley already has a high amount of renewable energy – about 30% – in its standard generation mix, the premium green energy program was driven by customers who wanted the option of purchasing 100% renewables, according to Joyce Kinnear, program manager.

“We’re going to be starting a re-launch of the [premium] program and perhaps do a little re-branding … just to make sure there’s a distinction in the customer’s mind between what our program offers in addition to what the department is doing for all customers.”

And although LADWP customers experienced some confusion between the green power program and renewables in the standard power mix, there has been no indication that renewable portfolio standards are impacting program participation, according to Gero. “As long as [customers are] reasonably secure that we are, in fact, providing them with renewable energy above and beyond whatever the department provides as a baseline, they’re happy to continue to participate,” he says. “There’s a committed group of people who really just want to support the development of a renewable energy industry.”

At Madison Gas and Electric (MGE), which already has both a green pricing program and state requirements, even more customers are willing to pay a premium to go above and beyond state standards. As such, the utility plans to triple its renewable energy offerings “in response to customers’ growing concerns about global climate change and their desire to take action through their energy use.” MGE’s existing green pricing program provides Wisconsin-based wind energy to about 4,300 customers. With the expanded program, more than 12,000 customers will be able to choose to receive all or part of their electricity from clean, renewable wind energy.

For in-depth information on specific utility communication efforts around renewable energy as part of the standard mix, see the following case studies in Section II of this report:

- LADWP learns lessons, makes fixes to extensive Green Power for a Green LA program
- Silicon Valley reaching for 7.5% enrollment in 100% green program (originally published in February 2007)

CASE STUDIES

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

Standardized technology spurs growth of net metering program

Company Profile

Central Hudson Gas & Electric Corporation is a regulated transmission and distribution utility serving about 367,000 customers in eight counties of New York State's Mid-Hudson River Valley. Central Hudson delivers natural gas and electricity in a 2,600-square-mile service territory that extends from the suburbs of metropolitan New York City north to the Capital District at Albany.

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Net Metering is Central Hudson Gas & Electric's program that allows participants to sell the excess electricity generated through their homes' solar power systems back to the utility. Utilities in New York are required to offer net metering of residential photovoltaic (PV) systems up to predetermined thresholds. PV systems up to 10 kW are welcome in the program. To qualify, they must meet equipment and installation requirements established by the state.

The New York State Energy Research and Development Authority (NYSERDA) offers a number of attractive incentives for customer-installed generation, including rebates that can reduce the cost of systems from 40% to 70%. NYSERDA also offers low-cost financing. New York State and federal tax incentives also encourage customers to install renewable energy generation. The state has developed similar net metering programs for small, residential windmills and farm-based biogas systems.

Customers who sell energy back to the utility receive a special rate or credit. "If, by the end of the year, their power generation has exceeded their use … we will issue that customer a check," notes spokesman John Maserjian. "Participating customers sell energy back to Central Hudson at both delivery and supply rates rather than just the supply rate."

Customer-installed solar or wind generators operate in parallel with Central Hudson's electric grid. To receive funding, they must use NYSERDA-approved installers, whose information is posted on the utility's Web site.

Developing a network of contractors has been vital to the net metering program. The first step a customer takes in joining the program is to contact one of the installation contractors who are listed on the NYSERDA site or through a link on the Central Hudson site. "These contractors understand how the system works. They basically work directly with the customers and help them obtain financing through the state. They also work with Central Hudson in submitting applications and arranging for system inspections," Maserjian explains.

The state's immediate goal is the expansion of the statewide network of installation contractors. Through this network and its use of standardized technology and services, the cost of solar technology is expected to eventually decrease, which is part of the overall goal, notes Maserjian.

Net metering program expanded

Central Hudson's net metering program is the first net metering program in New York to approach its threshold, which in Central Hudson's case was 800 kW. The state assigned each utility a threshold, based on its peak load in the late 1990s. In January 2007, the New York State Public Service Commission (PSC) granted Central Hudson an increase in enrollments from 800 kW to 1,200 kW, which will allow more customers into the program.

Central Hudson requested a program extension in the fall of 2006, when customer-installed systems were reaching the maximum approved level. Utility leaders quickly took action in order to maintain the momentum of the program. "We felt that in order to work with the spirit of this program that we should increase our threshold so that more local customers could participate; otherwise interest in these systems would decline and we did not want to see that happen," Maserjian states.

"There's a high level of interest in renewable energy here in the Hudson Valley. Our customers are sensitive to environmental issues and we've had great success with the program, not only through the work that we've done but also because of a strong installation contractor base that works in our area. They're marketing it as well," says Maserjian.

Currently 138 Mid-Hudson Valley residents are using net-metered PV systems or solar panels to convert sunlight into electricity. More than 36 requests for approval are under consideration, and that number continues to increase. A typical PV system in the program is 2.5 kW to 3 kW, he adds.

"Our customers are sensitive to environmental issues and we've had great success with the program, not only through the work that we've done but also because of a strong installation contractor base that works in our area. They're marketing it as well."

At this time, few customers actually produce excess power but nevertheless they are benefiting from having on-site renewable generation. "There are some customers who create excess power from time to time, but very few actually have a net generation by year end," Maserjian comments.

Standardization the key to program success

Central Hudson has played a key role in developing solar system standards, which has set the stage for the increase in customer installations. Central Hudson engineers have worked with the PSC, other utilities and installation contractors to determine the qualification standards for net metering programs. Interconnect standards developed in the late 1990s designate the type of equipment that may be used to properly and safely interconnect with the electric grid. "Under the state program only the type-tested equipment certified by state-approved installation contractors may participate in net metering," Maserjian says.

Standardization of equipment was necessary before net metering could hold its own as a viable program. "I think initially the biggest challenge was the number and types of systems that we were receiving applications for early on in the program … before the standardization," he explains. "That was a tremendous help both for the installation contractors and for Central Hudson. Now the contractors could confidently market a system knowing it would be accepted by Central Hudson. At the same time, we had a higher level of confidence in the systems that were being installed."

Before standards were developed, "I have to say it got off to a slow start," says Maserjian. "Once these standards were approved and the certification process was developed, the net metering program was able to grow quite quickly."

In addition to helping develop net metering standards, Central Hudson has worked with the PSC to design the appropriate tariff for qualified customers.

Central Hudson's engineering department handles the application and certification process. In considering applications, Central Hudson follows the New York State Standardized Application Process. Once a customer is approved for interconnection, he may begin construction and he may contact an engineer at Central Hudson to schedule an interconnection test.

Marketing plays up cost savings

Central Hudson's primary marketing vehicle is its Web site, which includes detailed information on the program. The utility also promotes net metering at various environmental fairs and trade shows that are held throughout the service area. Installation contractors market the program separately, says Maserjian.

The marketing message focuses on both environmental and cost-saving benefits. "I think our customers are attracted by the opportunity to generate their own power using a clean and renewable source. We tell our customers that if they are interested in taking advantage of this special program, net metering will provide a special benefit that includes [reimbursing them for] the supply and delivery costs. Any excess energy they produce is credited to them. They receive credit when a home generates more energy than it's using," Maserjian says.

FYI

Net metering is in the early stages of what Central Hudson sees as a growing relationship between the utility and its customers that will benefit both.

Both sides win

Net metering is in the early stages of what Central Hudson sees as a growing relationship between the utility and its customers that will benefit both. "One of the things that we've looked at over the years is distributed generation, particularly during peak days. To the extent that these systems are operating at full capacity on those hot summer days when load is at its highest, they could offset some of the pressure and strain on the local grid during those times," Maserjian relates.

The program is buoyed by NYSERDA incentives, which represent "a big savings" and are "a major driver under this program," he adds. "The costs of the systems are high. NYSERDA is able to offer these rebates in order to encourage customers to try the system and to spur demand that may not otherwise take place due to the high cost of solar PV systems."

Working with customers in the program "has helped us learn what our customers are looking for in terms of energy production and green energy programs. Additionally it helps us gain experience with systems that are interconnected to our grid," he adds. "We have learned that they're very interested in the environment and energy independence. They are more than willing to support renewable energy. Those that have the means are willing to make the investment."

LOS ANGELES DEPARTMENT OF WATER & POWER

LADWP learns lessons, makes fixes to extensive Green Power for a Green LA program

Company Profile

LADWP is the largest municipal utility in the nation, serving about 640,000 water customers and 1.4 million electric customers in a 465-square-mile service territory. The utility's total generating capacity is 7,200 MW. LADWP's operations are financed solely by the sale of water and electric services. Capital funds are raised through the sale of bonds. A five-member Board of Water and Power Commissioners establishes policy for LADWP.

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The Los Angeles Department of Water and Power (LADWP) offers a broad spectrum of environmentally focused programs that serve the utility's goal of improving the quality of life in Los Angeles – all under the Green LA banner. The following programs are designed to encourage and enable customers to take action and become involved:

- Green Power for a Green LA;
- Trees for a Green LA;
- Energy Efficiency for a Green LA;
- Solar Energy for a Green LA;
- Electric Vehicles for a Green LA;
- Recycling for a Green LA; and
- Educational Services for a Green LA.

The Green Power for a Green LA Program, launched in 1999, is a residential and commercial program that supports cleaner energy resources for Los Angeles. By signing up, customers contribute to more renewable power sources at LADWP. Participants pay a premium on their bills and can choose any level of participation up to 100%. "They pay a three cent per kWh surcharge for the portion of their energy they receive from the program," reports Gary Gero, director of energy efficiency and renewable solutions.

"The default [premium] is 20% of the customer's power from green power. Most customers – certainly 99% of them – are on the 20% [participation level]. Businesses can choose from as low as 1% up to 100%. The minimum is 500 kWh for a small business customer and 1,000 kWh per month for a medium or large business customer."

Customers receive two complimentary compact fluorescent bulbs when they sign up for the program. About 25,000 residential and 2,000 business customers are enrolled.

Green power on deck for re-launch

The green power program has experienced great success as well as various growing pains since it appeared on the scene. Some confusion has arisen over just what it means to be a green power customer, especially since the utility board adopted an ambitious renewable portfolio standard for the department. This standard mandates that 20% of LADWP's power will be supplied by renewable energy by 2010. "That has led to a little bit of confusion among our customers, who wonder what it is they're signing up for. We're going to be starting a re-launch of the program and perhaps do a little re-branding … just to make sure there's a distinction in the customer's mind between what our program offers in addition to what the department is doing for all customers," Gero explains.

But there has been no indication that renewable portfolio standards are impacting program participation. "What customers are telling us is that as long as they're reasonably secure that we are, in fact, providing them with renewable energy above and beyond whatever the department provides as a baseline, they're happy to continue to participate," he says. "There's a committed group of people who really just want to support the development of a renewable energy industry."

Another area of confusion for some customers has been deciphering utility lingo associated with the program, such as kWh charges. The utility is considering simplifying the fee to eliminate this confusion. "We're looking at the structure of the program as well. Right now we charge a surcharge on a kWh basis. We see other programs where it's more of a fee or a contribution that is not directly tied to the amount of energy used. It would certainly simplify it for our customers if they understood they could just contribute [a flat fee of] $5 or $10 a month."

The core of green power supporters appears quite secure in the program, but can LADWP raise the bar and increase the numbers? Or will program leaders have to be content to maintain the program at the current rate of participation? "We have an opportunity to continue to grow the program. We've been fairly level now for about four or five years in the program and it seems to me that … we have room to grow," Gero states.

FYI

LADWP will be unveiling some big news regarding green power that should allay any confusion surrounding where the program's energy is coming from or how customers' funds are used.

Solar plant coming for green power

LADWP will be unveiling some big news regarding green power that should allay any confusion surrounding where the program's energy is coming from or how customers' funds are used. The utility is looking into generating its own renewable power with a solar power plant that would be highly visible to Los Angeles residents. Green power customers would be publicly acknowledged for the plant's existence.

Renewable prices have shown a slight decrease in the open market, where costs frequently drop slightly below the three cents per kWh green power customers pay. This has resulted in a surplus of $4 million, which would be used to pay for a fairly large solar power plant, Gero says.

The solar plant isn't expected to meet the energy needs of all 27,000 or so green power customers, but it could provide a significant portion of the generation. "One of the exciting things we're going to do is take that surplus and build a small renewable energy plant here in Los Angeles that our customers can go and look at. It will leave no doubts about what their money was used for and where they're getting their energy," says Gero.

"We're looking at a couple of different solar technologies – a Stirling engine type of plant and a concentrating solar type of plant. We're doing some preliminary engineering feasibility studies on both of those [technologies] and looking for some LADWP-owned property [on which to site the plant]. It would be directly connected to the grid," he adds.

The new plant is one solution to questions and sometimes harsh criticism the program has received regarding the sources of the renewable energy used in the program. This was another cause for program dropouts. As with the other challenges the program has met along the way, program leaders have responded positively with a mindset focused on continuous improvement. “Our program has existed for a long time, and it did go through a bit of a difficult time several years ago when there was some question about the energy that we were providing to our customers and whether or not it was, in fact, new renewable,” Gero states.

“We did have some customers drop out of the program over concerns that what we were providing wasn’t meeting the intent of what they had signed up for,” he adds. “We’ve corrected that. The power we are providing to our customers is [now] certified new renewable from the marketplace. We want to take it to the next step and actually show people a solar plant ‘brought to you by the green power customers of Los Angeles.’”

From over-marketing to under-marketing

Green power program participation has remained flat for several years. In fact, it has decreased from its high point of 30,000 customers. But different situations have contributed to the decline, including the antiquated customer information system, which does not transfer participants back over to the program once they have moved. “They have to re-sign up when they go to another new account and they don’t always sign back up,” Gero says.

Green power hit another brick wall when accusations surfaced in the media claiming the utility was spending too much of the customers’ money on marketing the program. Over-marketing gave way to under-marketing, and this state of affairs also impacted customer enrollments. “We faced some controversies over our marketing practices some years ago as well. We took some criticism for over-marketing the program and as a result, there’s been a bit of a backlash and we haven’t actually marketed the program other than through an occasional bill insert,” Gero explains. “I think the answer lies in a middle-ground approach. You do need to do some marketing but you need to be careful about how you market and how you spend money in marketing.”

For LADWP, these setbacks have become lessons learned that are serving to strengthen the program in the long run. For example, building the solar power plant will provide a living example of program results and serve as a natural marketing vehicle, Gero says.

The trend – diversify and consolidate

Green LA is an umbrella program that consolidates a diversity of renewable energy, energy efficiency and sustainability programs, products and services. Gero’s title of director of energy efficiency and renewable solutions reflects the department’s approach. His goal is to help customers create a sustainable lifestyle and help protect the environment while reducing the utility’s energy load. “It’s all in one organization, and we clearly see the connection. We always tell customers the best thing you can do for yourself and for the environment is to not use our product at all. We help them through providing free compact fluorescent lights and offering rebates on refrigerators and air conditioners, and educating consumers about how to use energy wisely,” he relates.

"The good thing is that we are able to co-brand and cross-sell what we're offering. It's all considered Green LA, and we have a Green LA brand and phone number. Customers call one number to talk about energy efficiency, the green power or solar programs, and any of the other programs we offer, such as our tree planting program."

LADWP is taking integration a step further by integrating interdepartmental functions, whereby the power side of the business is working alongside the water side of the business. "That wasn't always the case in this utility. They have always been considered separate organizations with separate functions, budgets and staff. So we are able to talk more broadly about using energy and water wisely," Gero says.

Following the marketing controversy, Gero found that this integrated approach was useful in "very quietly and inexpensively" marketing the green power program, often at community events, in tandem with the rest of the Green LA offerings.

Generous funding promotes sustainability

The Los Angeles utility has been partnering with customers for some time and has developed what is believed to be the largest solar incentive program among municipal utilities in the country. This program was recently re-launched. "It's another program that was very, very popular and ended up with 500 customers on a waiting list trying to get rebate money for their solar installations. We worked through all those issues and now we're promoting solar energy again to our customers," states Gero.

With the heavy commercial construction activity taking place in Los Angeles – particularly in downtown condominium projects – many builders and developers are taking advantage of generous building rebates. For large projects, rebates of up to $250,000 are available. "In December, we launched a specific incentive program for U.S. Green Building Council certified sustainable building projects. We're looking even beyond energy efficiency in saying that if you build sustainable [projects], and you include energy and water efficiency in that sustainable construction practice, we'll reward you at a higher level than if we just counted the area of energy efficiency by itself."

LA is already quite built-out in the residential building segment, "so for residential customers, we largely offer to replace [appliances such as] older air conditioners, refrigerators and pool pumps," Gero notes.

Rebate amounts for the small solar installations that qualify for the solar rebate program are substantial as well, he adds. "Customers can expect about half of their system to be paid for by the department."

Rebate funding for all these programs is provided solely by LADWP. "We have specifically set aside [funds] within our budget for public benefits programs," says Gero. The related energy efficiency programs "are also paid for out of that same set-aside, as are the tree program and the low-income rate discounts."

New utility/customer model emerges

Program leaders have confirmed a strong business case for promoting and funding a diversity of green solutions that contribute to a sustainable lifestyle. Small solar installation, for example, “help us relieve congestion on the grid,” notes Gero. “If there are lots of small power plants out in the community, it relieves congestion, so that’s always a good thing. We want to support our customers in generating for themselves.”

The relationship between utility and customers is rapidly changing as these solar installations take on the role of little generating stations scattered throughout the community. “It is a different model for the utility. The old model of course is big, central power plants that distribute energy across the city. The idea of having lots of little power plants spread all over the city provides some security … [particularly] in a post-911 environment,” Gero comments.

“We want to see the solar technology continue to develop and become even more affordable. Our primary goal in the program is to help support lots and lots of residential customers. Since September, when we reopened the [solar] program, we’ve had 300 participants. We’re getting a lot of interest in our solar program.”

> **“Our primary goal in the program is to help support lots and lots of residential customers. Since September, when we reopened the [solar] program, we’ve had 300 participants. We’re getting a lot of interest in our solar program.”**

Besides the re-launch of solar and green power programs, LADWP is in the process of ramping up energy efficiency programs. “Last year we spent about $8 million on energy efficiency and this year we’re likely to spend about three times that, about $24 million. So we’ve rapidly expanded the programs,” says Gero.

New marketing strategies fit in with the new customer model. Ever aware of the danger of over-marketing, program leaders have learned to follow more cost-effective promotional avenues. LADWP is teaming up with manufacturers and vendors of energy efficient equipment, who are taking on a lot of the marketing chores. Customers save in energy costs over time, and the utility pays basically all of the incremental costs to upgrade to energy efficient appliances and equipment. Vendors educate customers and promote these cost savings in marketing their products.

“We’ve changed our rebate levels to pay, in most cases, 100% of that incremental cost between the standard and the most efficient equipment. So there’s no reason for customers not to go to the most efficient equipment,” Gero says. “It’s still cost effective for us. We’ve done the calculations and we have determined we can pay that entire incremental cost and it’s still cheaper than for us to generate.”

While making a strong push in solar, green power and energy efficiency, LADWP is joining in the community spirit with a campaign to provide a huge number of trees to Los Angeles residents. What could represent the sustainable model better than trees? “The mayor has set forth a goal for one million trees to be planted in Los Angeles. So we’re a key component of that. Residents can receive up to seven free trees from us and businesses can get up to 50 free trees,” Gero says.

CENTRAL VERMONT PUBLIC SERVICE

'Energy happens' in CVPS Cow Power program

Company Profile

Central Vermont Public Service, Rutland, Vt., is an investor-owned company providing energy and energy-related services to customers throughout Vermont. CVPS, the largest of the state's 22 utilities, serves 151,000 customers across the state. Subsidiaries are Catamount Energy, a wind energy developer, and SmartEnergy, a water-heater rental business. The Home Service Store is an affiliate national home maintenance and repair service.

Editor's note: This case study was originally published in* Chartwell's Best Practices for Utilities & Energy Companies *in April 2005.

By linking its new renewable energy program to local interests, Central Vermont Public Service (CVPS) is off to a strong start – and according to the company, an even stronger future – for Cow Power, a renewable energy pricing program. According to CVPS, this is the only green energy program that links farm generation, customers and the environment. In addition, an appealing logo and catchy tag line – "Energy Happens" – bring in a touch of humor and add interest to what is essentially electricity made from rotting cow manure.

The first phase of Cow Power generation is the work of a sizable family business, Bridport, Vt.-based Blue Spruce Farm, and the farm's 1,500 dairy cattle, who are doing their part to keep the farm generator pumping electricity into the grid. According to one of the farm owners, Earl Audet, "The girls are now officially producing two streams of income – a milk check and a power check. This is one more way to diversify the farm, improve our bottom line and manage our manure responsibly." The farm collects the four cents-per-kilowatt-hour premium from the program as well as 95% of the market price for the energy.

Capitalizing on customer interest in sustaining local farms and the environment, Cow Power has attracted 1,100 subscribers in its first six months, with virtually no money spent on advertising.

Most of the sign-ups proved to the 151,000-customer utility that customers will join and have a sense of loyalty to a green energy offering when they feel a sense of connection with the program. In this case, many of those signing up live in the county where the first phase of Cow Power originates. They appreciate the local environment, they are familiar with the farm that is generating the fuel, and they can see the direct benefits of joining the program.

CVPS surveys customers to gauge interest

A couple of years ago, some staff members at CVPS began discussing the possibility of developing a renewable energy program. Soon they were talking to outside groups – environmental organizations, the Vermont Public Service Board, Vermont Department of Agriculture, renewable development programs and others.

"It has been a lengthy process," says Steve Costello, director of public affairs. "We hired an outside market research company to look at customer interest – not only in Cow Power but in a wide variety of renewable energy products that we might be able to offer."

The utility commissioned ORC Macro International of Burlington, Vt., to survey 525 residential and business customers by phone in July 2003. The survey, which had margin of error of 5%, was very detailed in part because utility leaders were interested in getting data on several issues. These included:

- the general interest level in renewable or clean power in Vermont;
- the importance of renewable energy to Vermonters;
- the importance of maintaining a farm economy in Vermont;
- the importance of various environment benefits of green power;
- their level of concern about power planning in Vermont;
- their rating of the importance of renewables in power planning;
- their willingness to pay extra for renewable energy; and
- how much they might be willing to pay.

According to Costello, two issues stood out in the survey:

- 75% of those who liked the idea of renewable energy said that the environmental and particularly air and water quality benefits of a green energy program would play a significant role in their decision.
- 76% said the potential for helping to keep farms in business, maintain a strong farm economy and keep land open was one of the reasons that they would likely support a renewable energy program.

FYI

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Methane gas was not the highest-scoring choice for renewable energy. Solar, wind and hydroelectric scored significantly higher. "But we wanted to offer something that we thought would be significantly meaningful to our customers. And the answers we got about wanting to keep land open and wanting to help the Vermont farm economy were really meaningful. They're close to home. You would be hard pressed to find someone in Vermont who doesn't know a farmer."

In March 2004, CVPS asked the Vermont Public Service Board for permission to offer Cow Power, and received approval in July 2004. The program was finalized and rolled out in September 2004.

What customers say vs. what they do

Survey results were encouraging, although the CVPS group was well aware that positive survey results don't always translate into active membership in a planned program. In the end, the survey questions centered on marketing. Of those who would pay a premium for renewable energy, the survey they found that nearly 75% said they would pay more for wind; 65% would pay more for hydroelectric; 60% would pay more for solar; and 54% would pay more for generation from methane or farm byproducts.

Of those who would be interested in renewable from methane sources, 90% said they would be willing to pay a premium. Within that segment 4% said they would pay more than 25% more; 2% said they would pay 21% to 25% more; 6% said they would pay 16% to 20% more; and 5% said they would pay 11% to 15% more.

After the program rolled out, customers were paying 12 cents to 13 cents per kWh for Cow Power, or about four cents more per kWh. They can choose to have one-fourth, one-half or all their power from Cow Power. Customers who choose the 100% option are paying about 33% more. Those who choose to have half their energy from Cow Power are paying 15% to 16% more; and those who choose one-quarter Cow Power are paying 8% to 9% more.

The program is just six months old and in the early stages of marketing, "but what we're finding is that the numbers for those who said they would pay a really high premium are probably going to ultimately prove to be pretty accurate. We may not get quite the 4% who said they would pay 25% more, but I think we will get the 2% of customers who said they would pay 21% to 25%," notes Costello, which would be above the utility's initial expectations. "Right now almost half of the customers who have signed up are getting either 50% or 100% of their power from Cow Power, so they are paying a substantial cost."

Family farm serves as model facility

CVPS needed the full participation of at least one local farm before plunging into Cow Power, and fortunately the utility had a longstanding relationship with Blue Spruce Farm. "We've had energy efficiency programs for farms over the years and this is a farm that we've done a lot of work with," Costello explains, adding that the family owners are very progressive and had been trying to find a way to better manage manure. This farm now stands as a model to other farms; CVPS is in discussions with eight to 10 farms across Vermont.

The program requires an investment of time and money from the farm, which then reaps financial benefits. "This is really unique because other farms have generated electricity from methane but they have typically used the power themselves or it has been net metered," in which case the most financial impact it could have would be to offset its own power use, Costello says. "No one has ever created a market like this and encouraged farmers to do this and to create the kinds of financial benefits for the farm that this offers."

Blue Spruce Farm is expecting to cover the cost of its own power and realize a 100% increase as well, Costello adds. The farm had been paying about $70,000 a year for power but expects to earn about $140,000 a year through selling their power to CVPS. In addition, after the manure is used in the power-producing process, it can be dried and used in bedding, which will save another $60,000 annually in bedding costs.

Blue Spruce Farm expects to produce about 1.7 million kWh of energy per year. The utility entered a contract to purchase all output from the farm's facility.

The investment in the methane facility is about $1.2 million. Blue Spruce Farm has contributed about $800,000 of that amount. Additional funds have been available to the farm from state and federal grants as well as the CVPS Renewable Development Fund, which distributes grants for such projects. This fund was started with annual insurance refund money due to CVPS following the sale of its share in the Vermont Yankee Nuclear Power Plant in 2002.

The Audet family of Blue Spruce Farm has built an 800,000-gallon covered pool with hot water pipes running through it, Costello explains. "The manure is pumped into a big tank where water pipes heat it to 101 degrees, the temperature of a cow's stomach, and the manure continues the digestion process that was going on in the cows' stomachs. It stays in there for 21 days. As it's digested and as the bacteria work on it, more and more methane is created. The methane after 21 days is siphoned off and the gas is burned to power a generator."

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The manure that's left is pumped into a separator in another area, where the liquids and solids are separated. The liquids are pumped into a holding tank and can then be used to spray on the fields as fertilizer. The solids are sent on a conveyor belt into a separate storage facility where they can be composted and sold as fertilizer or dried and used for bedding.

Build it and they will come

CVPS leaders are pleased with the Cow Power participation rate – 1,100 customers have signed up in the first six months – in that it has been a good response and a manageable number for rolling out the new program. This is about the number that Blue Spruce Farm can sustain, with the varying levels of Cow Power customers are purchasing; thus, CVPS is getting itchy to sign on the next farm.

Costello points out that the bases are covered if there are ever lapses in availability of generation. "If we run into periods where we're customer-rich and supply-poor, the [utility will] go into the market short term and buy RECs [renewable energy credits], first from farm methane if we can find it and if not, from other renewables such as wind." Another option is to use the four-cent premium to increase the amount of money available for farmers in the CVPS Renewable Development Fund.

Still involved in getting farms on board, the utility has spent little on marketing to the public as of yet. CVPS has advertised Cow Power on bill inserts and through media publicity and public speaking engagements. Customers can enroll through the Web site, enrollment forms on bill inserts and flyers in chamber of commerce literature. "When a customer signs up, we send them a brochure that answers every question they might likely have," Costello explains. "We send them a bumper sticker with a CVPS Cow Power logo" and the program's tagline "Energy Happens." The program has another slogan on bill inserts: "CVPS Cow Power, providing renewable energy one cow at a time." As more farms sign on, the utility will begin spending more on marketing, Costello adds.

Benefits outweigh interconnection issues

Heading up the Cow Power program is senior energy advisor Dave Dunn, who, with a background in agriculture, previously headed up CVPS' energy efficiency programs for farmers and has spent a lot of time promoting Cow Power at community organizations. "His role is primarily to work with the farms that are interested in [renewable energy], to help work out the kinks, to serve as a liaison," says Costello.

"There are a lot of interconnection issues involved. We work out an interconnection agreement with the supplier, just like we would with an IPP or anyone else who we wanted to purchase power from. It hasn't been easy, to be honest. Typically, farms are not in the most populated areas. In this case, there was three-phase power at the farm but it took quite a bit of work with the engineering department, the relay department and the overall operations department to make it work. I expect we will have some challenges as we go down the path with other farms in the future. But we're committed to making it work. We feel very strongly that this is a renewable program that to us goes much beyond offering wind or some other form. The benefits to Vermont are just so significant in helping to make sure these farms are successful for our state, and for us, because these are big customers for us, and we want them to be successful," Costello asserts.

In comparing Cow Power to renewable energy programs around the country, CVPS leaders believe this program will be one of the few with staying power. "The national figures, according to the Department of Energy, show that there are about 550 … different types of renewable energy programs in which people are being asked to pay a premium of some kind. The top 10 of those programs represent 75% of the [total] customers who have enrolled. What that boils down to is that most of these programs aren't doing very well. They're not getting the customers excited and getting them into it," Costello asserts.

"I think five years from now we'll be able to tell you that Cow Power was an unqualified success. I will say that after six months, we're ahead of where we thought we would be at this point and every indication we've had is that we're going to be able to enroll numerous farms and ultimately create a demand for that power that's corresponding that's going to be generated."

From industry to local research, the lesson CVPS learned before rolling out the program – and one that is continuously reinforced in renewable energy literature and conferences – is that "you have to offer something that's local and that's meaningful to the local people," says Costello. "We can't just say we're going to sell wind from Texas here in Vermont. Even within our service territory, for example, the enrollment in the county where this first farm is located is twice what it is in any other county."

FERRY COUNTY PUD

PUD gets RUS grant to deliver solar power to isolated homeowners

Company Profile

Ferry County PUD is a rural public utility district in Republic, Wash. The utility serves the electrical needs of 3,130 residential and commercial consumers in the western portion of Ferry County, the eastern portion of the Colville Confederated Tribes Reservation and the northeastern portion of Okanogan County. The utility owns 868 miles of transmission and distribution line for a customer density of 3.6 per mile. The utility is a 10 MW average load, full-requirements customer of the Bonneville Power Administration.

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John Friederichs was just trying to help some of Ferry County, Washington's off-grid rural residents obtain reasonably priced electric service from the utility. But Friederichs may have stumbled upon something that will benefit other utilities and their customers in places he's never heard of.

Ferry County has done the research and stands as an example of how to earn federal support for alternative energy solutions that can assist isolated, off-grid customers.

With the backing of a USDA/Rural Utility Service (RUS) grant, Ferry County's new solar and line extension program for remote customers offers an alternative for area residents who have had no choice but to power their households with standby generators, inadequate solar systems and other off-grid sources of power. These residents live too far from distribution lines to feasibly pay for grid connections. The funds will be allocated for both line extensions and the purchase of solar photovoltaic systems.

In a nutshell, Friederichs – conservation director of Ferry County PUD – submitted a request for funds that would enable the utility to provide line extensions for those who qualify, or PV systems for those who don't. The plan sounded good to the RUS, and soon Ferry County PUD was looking at a grant award of $888,406. After nearly a year of administrative work, the first portion of the funds was expected to arrive in June 2004.

These funds will enable qualified area residents to purchase line extensions or solar power under low-interest, long-term loans. "The idea that for $45 a month they could have all the power they ever dreamed of ... people are absolutely thrilled," Friederichs says.

Grant request not an easy process

"We've been trying for several years to figure out a way to get power to folks who can't afford it. We have a lot of very isolated residents who live a mile or more beyond any facilities at all. I'd just been working with someone who lives three miles off the power line. She has a special needs daughter and mother she is taking care of, and she was running her home off of tractor batteries that she charged with her car."

Friederichs was working on this case when someone dropped the grant information on his desk in early 2003. The RUS had announced the availability of $11.3 million in federal funds for high-energy-cost rural communities authorized under section 19 of the Rural Electrification Act of 1936. The grant funds were to be used "to acquire, construct, extend, upgrade, or otherwise improve energy generation, transmission, or distribution facilities serving communities in which the average residential expenditure for home energy exceeds 275% of the national average." The consumer's energy costs must be 23 cents/kWh or higher.

The wheels started turning. "I thought, 'it has to cost at least 23 cents/kWh to make electricity with your Subaru.' So I started researching and talking to people and gathering up information."

In preparing to submit the grant request, Friederichs did thorough research to determine whether the utility could qualify for the grant under the USDA/RUS requirements. This included conferring with an engineer specializing in off-grid power, who helped Friederichs prove that people using solar or portable generators are paying far above the 23 cent/kWh requirement. A local resident who has been off-grid with a solar system and backup generator since 1982 had kept meticulous records of money he spent on power generation, including gas, oil, replacement parts and maintenance. His fully burdened cost per kilowatt hour was about 41 cents, Friederichs discovered.

Friederichs also calculated the cost of regular line extensions at $30,000 to $35,000 per mile on conventional power lines.

"Most people don't have that kind of money to do this. So I found what the best available financing would cost those people for that installation. Calculating the cost of the installation and the expected use of the electricity in kilowatt hours, I broke it down over the period of the loan, which is very short; no lender would write it for a long period of time. The interest is about 11%. I came up with a fully burdened cost of electricity for that time period that was over 23 cents" for any line more than about 1,200 feet long.

"I wrote all this up and sent it away, and lo and behold they thought it was a good argument and gave us a grant for $888,000."

In July 2003, Friederichs sent in the grant application. Then, between July and December 2003, a large portion of his time was spent fulfilling federal regulations regarding cultural, archeological and historic concerns relating to the grant request, since almost half Ferry County Public Utility's service area is part of the Colville Confederated Tribes' Indian Reservation. The 12 tribes in the confederation were satisfied with the utility's plan and gave their approval for the project. The USDA/RUS granted the money to Ferry County PUD. By the end of May 2004, Friederichs had finished faxing the last bits of information to the RUS and was expecting half the grant money by early June.

Financing package or solar opens door to affordable power

Normally, people who live within 100 feet of the power line pay a minimum charge of $250 to have the utility install a line extension and meter box. The grant money will be used in a similar way for people who live farther from the line and would incur costs of upwards of $30,000. "So what we can do under this program is a conventional line extension. We finance it at zero interest for 30 years, and for [those who qualify for] solar we will finance for 20 years. We base that on the expected life of the systems." The line extension or solar system then becomes part of the property.

Solar was the power source of choice for customers who were too isolated to consider line extensions. Other generation sources were considered briefly but rejected. "There isn't really anything else until fuel cells grow up ... and even with those you have to haul fuel," says Friederichs.

"Generators? We've been there," he adds, recounting stories of how many times he has seen people rebuilding and replacing them. They are ideal for standby, emergency use, but some residents in the service territory depend on them as their main power source. "With a gas generator you might have 2,500 hours of life ... and in a couple of years they're junk. Propane is another problem. We tried propane generators for some of our grid systems and none of them are designed to run continuous duty."

What about solar? No mechanical problems there, but cloudy days are a certainty, and they don't pull enough power to run an entire household. "Oh, yes, you're going to have to use propane for anything that makes heat; if you're heating water or heating your home you're going to use wood, propane or oil." Solar is good for lights, refrigerators, small appliances. It was chosen because "it's secure; we can lock it in a box and it's a pretty mature technology. We know what we're going to get. It's very predictable and low-maintenance," and that makes it ideal as part of the utility's distribution system, Friederichs says.

FYI

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After coming up with the idea for the solar program, Friederichs has had calls from some groups in different areas of the country that are interested in launching similar programs. One group in particular has been unsuccessful in attempts to obtain grants for solar energy projects. Whether it was the timing or simply the right combination of facts, figures and demographics, Ferry County PUD is one of the first to walk through a door that seemed to be closed before now.

Friederichs has been studying proposals obtained from an RFP the utility sent out to manufacturers of solar systems. "We told them we wanted off-grid PV systems, and rather than specify all the equipment ... we told them we wanted three different systems, one of which would produce 2.5 kilowatts a day averaged over the year; one that would produce 5 kilowatts a day; and another that would produce 7.5 kilowatts a day. I left the specifications of the systems as wide open as possible. I specified some basics, such as the type of mount. We wanted a pole mount and we needed two-inch conduit coming out so we could go into a standard meter base ... but as far as the components of the system I left it pretty wide open."

Out of nine RFPs, three vendors responded with proposals. The utility board will select one of the vendors and give its recommendation to the country commission. After commission approval, the utility plans to order an initial stock of six to eight systems.

"We have 28 [qualifying residents] who we've already visited and approved under this program, for a total of $503,000. About one third of them are solar," Friederichs says. Customers must live a certain distance from the grid in order to justify under the terms of the grant that they're part of the high-energy-cost community. They will be subject to a liberal credit check prior to installation. The utility will determine which customers qualify for solar and which qualify for line extensions.

New customers thrilled to be getting power

A likely candidate for the solar program is the resident who has lived off-grid for six or seven years.

"He's pretty typical in that he has a gas generator ... and his solar installation consists of two panels or a total of about 300 watts. It will run a half-dozen lights, television and computer." That typical customer's solar system cost $3,000 to $5,000 for that little solar system. In contrast, Ferry County PUD's smallest system will be around 2,400 watts DC.

"So this customer will have eight times the generating capacity. He'll have 12 times the battery storage capacity so he can keep the lights on at night," says Friederichs. With the amount of electricity this customer is likely to generate, "he's going to be paying about $70 to $75 a month and he'll have power 24 hours a day. And he won't have to listen to [or maintain] his generator."

Ferry County PUD will be in on the decision-making process to help customers determine which system will be suitable for their needs. Friederichs estimates that 85% of customers will choose the smallest solar system – which is equivalent "to the largest system I've seen installed out there;" 10% will choose the mid-sized system; and 5% the largest.

> **"The large system has 64 panels. It will have eight pole mounted arrays of eight panels apiece. I don't expect that to be real popular. The price of that one is going to be almost $36,000."**

"The large system has 64 panels. It will have eight pole mounted arrays of eight panels apiece. I don't expect that to be real popular. The price of that one is going to be almost $36,000." That system will cost about $150 a month, plus the $15 monthly electric service charge and 6 cents/kWh. "That giant system will run small heaters. But normally we tell people if you want to make heat do it another way."

The residents are excited at the prospect of having reliable power that will be adequate for their needs, something they could never count on in the past.

"Everybody is thrilled that for the minimum payment of $45 a month, they could have all the power they ever dreamed of. The folks that have solar don't have enough and they haven't been able to afford more."

The basic solar system is going to cost around $18,000. It will be owned and installed by Ferry County PUD. The utility has hired an installer specifically for this program. This expense is considered an investment in the economic well-being of the community, which recently has seen its major industries – mining, logging and agriculture – fall into a slump. Job creation as well as support of customers who need power to survive and operate businesses is a benefit of the program. The RFP sent to vendors requires them to provide solar equipment training, which will add to the utility's knowledge base.

Looking back at the genesis of the solar and line extension programs for remote customers, Friederichs could not foresee where it would lead at the time.

"The idea that it's something that actually might go somewhere else and let some other folks accomplish the same thing is amazing," he comments. "It sounds like something that people have been trying to figure out and couldn't. We just fell into it. So if that part of it works well for others I think it's wonderful."

But realistically, it will take the right combination of factors for such a program to work elsewhere. “You have to have the right demographic makeup of people to make a program like this work. This is not something that’s going to work in downtown Atlanta, but I bet there are places in [other states] that don’t look much different” from Ferry County, Washington.

OGE ENERGY CORP

OG&E wind program achieves 1.2% take rate in first year, moves to add 80 MW to wind farm

Company profile

OGE Energy Corp., Oklahoma City, is the parent company of Oklahoma Gas and Electric Company (OG&E), the state's largest electric company, and Enogex Inc., a natural gas pipeline and energy marketing business. OGE Energy and its subsidiaries have about 3,000 employees. OG&E Electric Services, a regulated electric utility company, serves about 730,000 retail customers in Oklahoma and western Arkansas, and a number of wholesale customers throughout the region.

Editor's note: This case study was originally published in* Chartwell's Best Practices for Utilities & Energy Companies *in February 2005.

After a year of testing the costs and benefits of wind power on the electric grid in a real-time supply and demand program, Oklahoma Gas & Electric (OG&E) is in the early stages of adding an additional 80 MW to the original 50 MW of generation at a wind farm near Woodward, Okla.

With more than 9,000 participants signed on in the first year to receive all or part of their energy from wind, the program has caught on, just as OG&E customer research promised. The wind power program has been called a major step forward and one of the nation's largest wind power programs designed solely for a utility's own customers.

About one-third of the subscribers have chosen to have 100% of their electricity generated by wind, a positive indication of customer interest into the future. "Our customers told us they wanted a renewable energy program, and they have responded in bold fashion," states OG&E spokesman Brian Alford. "Their desire to participate in a zero-emission energy program, coupled with an effective education plan, has made OG&E's program a nationally recognized success story."

The program's low cost, flexibility and environmental benefits continue to draw customers. Additionally, the wind power initiative assists economic development for Oklahoma's rural areas.

The company looked to wind as an alternative generation source as a response to the interest in green or alternative energy. Wind is plentiful in Oklahoma, which ranks eighth among all states in wind power resources, making it an ideal location for such a program. Wind power is available only to customers in Oklahoma at this time, but OG&E is considering extending the program to Arkansas as well, Alford says.

OG&E introduced its wind power campaign in the fall of 2003 at the State Fair of Oklahoma. Alford reports hundreds of customer sign-ups from that event. During that time, OG&E initiated an interactive wind power Web site that provides detailed information and allows customers to subscribe online. On the site, customers can select various wind power levels, starting as low as 100 kWh, enter the amounts into an online calculator and find out the environmental benefits of the different levels of participation.

The utility assures customers that the wind-powered electricity they are using is coming directly from the OG&E power grid.

OG&E already has issued its second request for proposals from wind turbine producers, this time for 80 additional MW. "It has been more than a year since we last requested bids to determine the cost of adding wind to our system," Alford relates. "In that time, we've seen gas prices continue to rise, as well as the extension of federal renewable energy tax credits. From a dollars and cents standpoint, now is a good time to look at adding more wind and to weigh its value to customers."

A good plan all the way around

The program was developed as an option for all customers except the large power and light class customers, who chose not to participate. It was designed and presented to the Oklahoma Corporation Commission as a separate piece of its rate plan. The commission approved the "Green Power Wind Rider," which allows OG&E to include a subsidy for development of the renewable resource. OG&E was granted the right to set aside up to $400,000 annually for education and advertising, an amount that is collected from participating customers, Alford states.

An average residential customer can purchase wind energy to meet 100% of the typical home's electricity needs for about $20 per month. After a fuel credit is applied, the monthly charge amounts to $7.50. Besides the environmental benefits, this low monthly rate is a huge selling point for the program.

The base cost of the wind power is $2 per 100 kWh block, or 2 cents per kWh above OG&E's standard charge for electricity. Green power subscribers are exempt from the utility's fuel adjustment charge, currently at about 1.5 cents per kWh, which effectively lowers the premium for the wind power to about .5 cents per kWh. With the fuel adjustment credit, customers who purchase wind power are protected from potential fuel cost increases.

In addition to supporting public education of renewable energy, the wind power premium ensures that power plants are running on those occasions when the wind stops blowing.

The rate structure is clearly defined and has not been the source of confusion among customers. "The customer's bill reflects the actual wind charge and the credit," says Alford.

Program participants may call customer service and cancel wind power any time after the first three billing cycles. They may change their level of participation up to four times per year.

Wind power subscribers are a diverse mix, from individuals to large corporations. Included on the subscriber list are the University of Oklahoma, Oklahoma State University, the Methodist Church and large corporations such as Hitachi.

Wind farm becomes reality

Following positive results of customer research and approval from the corporate commission, OG&E planners issued RFPs to wind power developers for construction and operation of a wind farm that would power one of the largest single programs in the U.S. The winning bid came from FPL Energy, Juno Beach, Fla., the nation's largest wind power developer.

The $100 million project has boosted the local economy near Woodward, Okla., and ushered in positive public relations for OG&E. “We’ve enjoyed success from both an economic development and reputation perspective,” Alford comments. “That is reflected in our promotional materials, which carry the message ‘It’s a wind-win for Oklahoma.’”

The company signed a 15-year agreement with FPL Energy to purchase a half share in the 102 MW Oklahoma Wind Energy Center. The power is produced by 34 1.5 MW wind turbines at the wind farm. The Oklahoma Municipal Power Authority is purchasing the additional 50 MW for its wholesale distribution utilities in the state. Currently the wind farm houses 68 212-foot high, state-of-the-art turbines. FPL Energy owns and operates the generating equipment.

Education on the front burner

In organizing the wind power program, OG&E planners realized that green energy is a popular concept with many customers; but, they also knew that the concept must be translated into an understanding of how it works. With this in mind, they organized a strong community-based education and marketing effort. Built into the green pricing tariff is the $400,000 rate allocation that supports this initiative.

“We’ve enjoyed success from both an economic development and reputation perspective. That is reflected in our promotional materials, which carry the message ‘It’s a wind-win for Oklahoma.’”

“Our education efforts have been extremely successful in raising public awareness about wind power,” Alford relates. The marketing plan includes brochures, television, radio and print advertisements as well as participation in public events. OG&E representatives also have had strong visibility at community clubs and organizations.

A large part of the education efforts are focused in the schools. “We have produced a renewable energy workbook for elementary school students,” says Alford. “It’s available to teachers in the OG&E service area through our 2004-2005 Educational Materials Film and Video Resource Guide.”

The utility’s message centers on presenting wind power as a clean, renewable and efficient alternative energy source. In literature and public presentations, the utility points out that even a commitment to the minimum amount of 100 kWh of wind power per month for a year could have the same environmental impact as planting half an acre of trees. Wind power subscribers know they are responsible for helping diversify the utility’s energy portfolio. Each customer who chooses even a small amount of wind power helps set the stage for more wind power investment.

Although wind power has been a perfect fit for the utility and customers, it will remain a specialized portion of the overall generation mix. The future of the program and its further expansion revolve around the utility system’s “ability to digest the additional energy source,” Alford states. “We are very much a coal-based utility, so we want to ensure that wind doesn’t interfere with coal. Coal is less expensive than wind. What we want to ensure is that we’re not costing our customers money by impeding that coal.”

PACIFIC GAS AND ELECTRIC

Solar installations soar at PG&E; utility hoping to see market transformation

Company profile

Pacific Gas and Electric Co. is one of the largest combination natural gas and electric utilities in the United States. Based in San Francisco, the company is a subsidiary of PG&E Corp. With 20,000 employees, the company provides electric service to about five million customer accounts and natural gas service to about 4.1 million customer accounts in a 70,000-square-mile service area in northern and central California. PG&E is regulated by the California Public Utilities Commission.

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Solar power is hot in California. In the past few years, Pacific Gas and Electric (PG&E) has connected more than 10,000 solar customers to the state's electric grid, making PG&E the nation's leading utility in solar hookups. PG&E connected the 10,000th solar customer in February 2006. According to U.S. Grid Connect 2005 PV Market Report, in 2004, 51% of the solar systems installed in the US were in PG&E service territory.

Not only is solar the utility's most popular renewable energy source, the utility's solar program has drawn enormous response due to the incentives offered by the California Energy Commission and PG&E. Customers have flocked to PG&E to take advantage of rebates on photovoltaic installations.

Customers benefit by having their own source of renewable energy for a portion of their usage, and they also may sell power back to the PG&E grid to earn credits that are applied to their future energy use.

The California Energy Commission provides incentives in the Emerging Renewables Program, designed for customers with solar systems of less than 30 kW. For systems of 30 kW or larger, PG&E's Self-Generation Incentive Program offers incentives on solar as well as fuel cell, wind and cogenerations systems. In this program, PG&E has paid out well over $115 million in rebates for hundreds of solar projects.

"We provide the implementation for the Self-Generation Incentive Program, so we work with each of the projects as they go through the rebate process," explains Sara Birmingham, manager of the program. "Once they apply, they receive a reservation and they have 12 months to complete the project. We work with them to make sure they meet the milestones and provide all the necessary information in order to participate in the rebate program."

Because of the public interest and governmental support for solar energy, the two solar programs are slated to become a single $3.2 billion "super solar" program. "The future is very exciting because the solar aspect of the Self-Generation Incentive Program and the solar aspect of the California Energy Commission's program are going to be combined into a 10-year program that California is initiating starting in 2007. It is the largest program of its kind and it really speaks to California's dedication and commitment to solar energy," Birmingham says. "We're very hopeful that … as we move forward, the incentives will decline, installations will go up, and the price of solar will come down, so that the market will be transformed. We want to see that people are installing these systems because it makes economic sense."

"There will probably be a time in the future where solar projects don't participate in a rebate program, but I would say all of or nearly all of the ones that have been hooked up to date have participated in a rebate program," notes Birmingham.

A 2005 study by Navigant Consulting for the Energy Foundation, San Francisco, pointed to "the vast market potential for rooftop solar photovoltaic systems (PV) in the United States." The study outlined the expected market potential for solar energy in 2010 under a "cost breakthrough scenario."

In the state-by-state analysis, the study concluded that the potential U.S. market for grid-connected solar rooftop PV could reach 2,900 MW per year by 2010 if the solar industry could achieve a price of $2.00 to $2.50 per installed watt. This would be enough new electricity, brought online in just one year, to power more than 500,000 average U.S. homes. The annual market potential for residential and commercial building applications would amount to an annual market of about $6.6 billion in equipment and installations.

According to the study, there is enough suitable rooftop space on residential and commercial buildings to sustain this annual level of growth. The study found that residential and commercial rooftop space in the U.S. could accommodate up to 710,000 MW of solar electric power. "Solar energy has seen impressive expansion – 36% compounded annual growth for the global solar industry since 1999 – but it has far, far greater potential," said David Wooley, vice president of the Energy Foundation, at the time of the study's release. "This report illustrates that PV could make a significant contribution to future electricity supply in this country. This potential justifies state and federal support in the near term to stimulate new PV manufacturing investment, accelerate growth in system sales and help reduce the cost of PV systems."

Schools, Habitat for Humanity go solar

PG&E further supported solar energy by launching the Solar Schools Program in 2004. The utility has awarded more than 30 solar systems to schools throughout northern and central California and provides courses of study, teacher training and grant money for students to learn more about solar energy.

The Solar Habitat Program is a partnership between the utility and local Habitat for Humanity chapters. In this program, PG&E funds solar systems on Habitat homes in northern and central California and also provides training funds to assist the organization with solar installations.

PG&E is contributing more than $1.5 million in 2006 to these programs, which also receive funding from rebates and shareholders through the charitable contribution program.

Program is information rich

In the Self-Generation Incentive Program for systems greater than 30 kW, customers submit an application to PG&E. "We will screen that application for eligibility. We're looking for things such as whether it's sized appropriately for the facility and its energy usage, assuming that we have enough in the budget for that particular project, because it's been a very popular program over the years. We have had a waiting list since the program started in 2001. It's a much smaller waiting list than we've had in previous years," Birmingham says.

"We issue a reservation, which gives them the go-ahead that we have funding reserved for the project, and then they have 12 months to install that system. After 60 days, they have to show us that they're making sufficient progress on the project by submitting it for interconnection and showing us an executed contract with the vendor that's installing the system. They submit documentation so that we can ensure that the project is proceeding in good faith."

The program provides extensive information to customers. "We recommend they take it out for request for proposal, get at least three bids, and check to make sure [the vendors] are qualified and have contractor licenses. We also post information on our Web site, particularly about average system prices, and we encourage folks to make sure the bid is within the scope and numbers we have seen in the program," adds Birmingham.

Solar is "by far" the most requested renewable installation, but the program provides rebates for wind turbines, fuel cells, microturbines and internal combustion engines. Generators may use natural gas or renewable fuels such as waste from a landfill or wastewater treatment facility.

Most customers that Birmingham sees in the Self-Generation Incentive Program are commercial or industrial. The type of renewable energy source they choose depends on the company. "We have a lot of interest from a number of different companies and industries, including wineries. We have a lot of projects from cities, counties, public entities, educational facilities," Birmingham comments.

Projects such as fuel cells attract a different type of customer. "These are early adopters who are very interested in different types of technology. One of the projects that we did last year that was very exciting was a 1 MW fuel cell project at Sierra Nevada Brewery. They had a nice dedication attended by the governor … who was talking about his commitment to fuel cells and hydrogen highways."

"We issue a reservation, which gives them the go-ahead that we have funding reserved for the project, and then they have 12 months to install that system. After 60 days, they have to show us that they're making sufficient progress."

Payoff from six to 22 years

Many customers in the Self-Generation Incentive Program receive financing, depending on the project. "There are a number of different financial models, and a lot of the vendors will provide the financing. The vendor may offer a long-term lease arrangement whereby they own the generator, take advantage of those tax credits and sell the power to the person who puts it on his roof," Birmingham says, adding that this business model came along about two years ago.

Many customers pay for the systems up-front. "It depends on the reasons why they're putting it in. A lot of customers are putting in solar because they're a city or county and they want to lead by example. Those projects do take a little bit longer to pay off, because they're not able to take advantage of tax credits," states Birmingham.

"For the commercial businesses that are able to take advantage of tax credits, the payback period is coming down. It's still not as short of a payback as some other investments, but we have been told by some vendors that they have been seeing paybacks come down to as low as six years. We've also had projects within the program that have a payoff of 22 years. That's after the rebate."

Program doesn't need promotion

Regarding promotion of solar energy, Birmingham notes that although PG&E strongly supports it, there is no need to promote it in traditional ways. "In terms of marketing, the program has had a waiting list from day one. Instead of having a traditional marketing program for this, we've focused on education and outreach opportunities."

These educational initiatives have been overwhelmingly popular. "We provide classes on solar and siting to particular energy facilities as well as solar hot water classes that we offer free of charge. This year, for the first time, customers also are able to take classes online. In 2006 we are offering 30 or more classes … and every single one has been sold out. We want to increase those educational outreach opportunities because the interest is just phenomenal."

Birmingham attributes customer motivation to the incentives, which are attracting all of this activity around the solar program.

Although the solar program is significant, it represents only a speck in the overall generation mix. But the potential for growth is great. "When you look at the economics of solar, you have to understand that this is the beginning," comments company spokesman Paul Moreno. "When the automobile was introduced, it was very prone to flat tires and mechanical breakdowns, and it was very noisy. Obviously automobiles are far different than what they were in that time."

> "In 2006 we are offering 30 or more classes … and every single one has been sold out."

At this early stage, PG&E and other utilities in the state have their hands full just trying to keep up with demand. To make matters worse, silicon, which is used to manufacture solar panels, is in short supply. "The big challenge right now is actually getting panels and being able to ensure that that supply is coming through from the manufacturers," Birmingham says. "We do expect that silicon shortages should start to be alleviated by the end of 2007, according to the estimates I'm hearing from the industry." The majority of these panels are shipped from overseas, but there are plans to increase manufacturing capabilities in the U.S., she adds.

Birmingham's advice for other utilities interested in ramping up their solar programs is "to ensure that the statewide regulatory policy is consistent and try to look at the program as a whole. Because California was such an early adopter, it's been slightly fragmented as we looked at policies here and there. For any new states that are coming on, I would encourage them to look at the whole portfolio of energy policies together, such as metering legislation, such as the renewable energy credits … as well as the rebates. It's been a constantly evolving process in California." The foresight and timing of California's legislative and regulatory bodies have been the key to success in program implementation and customer uptake, she adds.

"We've had a great time working with our customers to help them realize these projects and to implement their dreams. I'm always amazed … when we go out to dedication ceremonies and there are always internal champions within the different companies. It's fun working with them because it really is their dream that they're implementing. Once they see those solar panels go up … they become internal champions within their environment and their communities."

RPU

Lessons learned: Tie green power into brand, be more proactive, less reactive

Company profile

RPU (formerly Rochester Public Utilities), a division of the City of Rochester, Minn., is the largest municipal utility in the state of Minnesota. RPU serves about 46,000 electric customers and 36,000 water customers, and has revenues of nearly $100 million annually.

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Rochester, Minn.-based RPU offers customers two renewable energy programs, wind and solar, in conjunction with the utility's wholesale energy provider, Southern Minnesota Municipal Power Agency (SMMPA). Other renewable efforts are underway as well.

RPU's goal is to support conservation and the environment in order to comply with a state mandate as well as customer demand. "We are mandated by the state to spend 1.5% of our gross revenues on energy conservation," says Walters, and part of this takes the form of renewable energy.

The utility's new comprehensive infrastructure plan calls for 7,880 MWh of the electric load to come from renewable energy in 2006. "The RPU board decided this year … that we're going to spend more than we're required to spend because our infrastructure plan told us that it makes good sense to do these demand side [and supply side] measures to meet the needs of the future … and that means we're going to go from $1.4 million to $1.7 million on our conservation programs." The funds for these programs are rolled into the rates, he adds.

The wind program is open to both residential and business customers, and has 848 customers participating. The average household in RPU's service area, which uses about 600 kWh per month, pays $6.00 a month for 100% wind power. Customers may choose any amount of monthly 100 kWh blocks for $1.00 each. Residential wind customers use about 272,000 kWh of renewable energy per month. Five C&I customers are on the program, also at 1 cent per kWh, for a total of 56,000 kWh per month.

The first two wind turbines were up and running in March 2003. The other four turbines were installed in February 2005. There are two 950 kW turbines and four 1,650 kW turbines for a total of 8,500 kW, according to RPU information.

RPU, along with two other municipal utilities, recently began offering SolarChoice, an innovative program that encourages the installation of solar electricity systems by helping to make solar installations more cost-effective. SolarChoice was designed to help close the economic gap by connecting customers who want to produce renewable energy with those who are interested in promoting the development of renewable energy sources. Customers who sign up as promoters pay a small amount of their choice on their utility bills each month. These funds are kept in the SolarChoice Fund and then passed on to the producers – or those choosing to install solar systems – once a year according to the SolarChoice payment formula. Promoters, of course, do not physically receive green electricity, but they are guaranteed that 100% of their contributions will be used to make incentive payments to the SolarChoice producers. Any electric customer may become a SolarChoice producer by installing a solar electric system and signing an agreement with the utility. Producers receive an incentive amount in proportion to overall solar energy produced. For example, if a producer generates 5% of the renewable energy generated by all of the producers, this customer would receive 5% of the payments.

RPU signed up 20 promoters in the first month of the program, says Jim Walters, director of customer relations. "Unlike our wind program – which is through our wholesale supplier and the wind turbines are a couple of hundred miles away – this is right in town, so we expect installations to go up in time."

RPU also considers geothermal heat pumps a renewable energy source. The utility offers an extensive geothermal program. "We developed a special rate for geothermal heat pumps because of their uniqueness, and we also have an economic incentive," he says.

"We have about 2.3 MW of hydro," he continues, which falls under the heading of renewable energy. In the future, RPU expects to purchase energy from a local waste facility as well.

FYI

Because of the increasing availability of green energy and because customers are coming to expect it to be part of the generation mix, the supplier may discontinue optional retail programs altogether. If that happens, renewable energy will simply be another form of the utility's generation resources and costs will be rolled into the rates.

Marketing and public relations

Renewable energy programs are marketed through bill inserts, the local paper's Web site, press releases and interviews for newspaper articles. As the retail arm of the wholesale supplier, RPU works in conjunction with the supplier to promote green power.

In the future, Walters expects big changes in marketing green energy programs. Because of the increasing availability of green energy and because customers are coming to expect it to be part of the generation mix, the supplier may discontinue optional retail programs altogether. If that happens, renewable energy will simply be another form of the utility's generation resources and costs will be rolled into the rates, he states.

In addition to standard marketing, RPU interfaces with the local chapter of the Southeast Minnesota Clean Energy Resource Team (CERT), a group that is charged with conservation and renewable energy efforts. "We had communication issues with the environmental community" and made the decision to join CERT "so that we would have our ear at the meetings and could respond," Walters explains. "One of our folks serves on that committee so that we are in direct communication with the environmental community."

The utility undertook a massive study, which involved consultants and public hearings, to develop a long-term infrastructure plan that would ensure adequate energy load into the future. CERT was closely involved from start to finish. "We were looking at demand side and supply side options. The environmental community was involved in that whole process," says Walters. "What we found was that we're going to focus our efforts on the commercial market because … we need to get into the commercial establishments and do audits" to more fully involve these customers in the conservation portion of the plan. The focus of the plan was to document growth to 2030 and to increase demand-side management programs and funding.

"The infrastructure plan also looked at renewable technology. We found that [purchasing energy from] the waste facility made the most sense," Walters continues, adding that the utility is currently in negotiations.

During organization of the infrastructure plan, RPU and CERT personnel attended meetings of both groups. The primary issue at hand was RPU's coal-fired power plant in town. "They want it closed down," Walter says. "They had their input, and as a result of that it's almost unprecedented but we're going to spend millions of dollars on advanced pollution abatement at our power plant. For this small plant – it's only 110 MW – we're going to spend a lot of money."

But RPU recognizes that "we still have fiduciary responsibility to all customers and we need to balance the opinion of some against what the majority of customers would want as well." The infrastructure plan has been the means to achieve that balance. "It really has guided us through this whole thing. We developed three or four options for dealing with our power plant, and we chose not the least-cost alternative but the middle ground. Our board agreed and we're going to be moving forward on it."

Pros, cons of coal plant must be balanced

The coal-fired plant became a dominant issue in the media in 2005. The majority of the news stories were generated from the public hearings that were part of the infrastructure plan development. "It was a very big issue," Walters relates. The bulk of communications was handled by RPU's communications coordinator, and Walters wrote an opinion piece that appeared in the local paper. "I wanted that balance … [between the notion that] the power plant is a really bad thing" and the actual impact it has on the environment. "I was not disagreeing with anything but what I wrote was pointing out some other factors." For example, information from a study released in 2001 by the Centers for Disease Control and Prevention (CDC) shows the impact of automobiles on air pollution. During the Summer Olympics, the city of Atlanta closed the downtown area to cars, among other measures that limited traffic. The CDC study showed "that decreased citywide use of automobiles in Atlanta during the 1996 Summer Olympics led to improved air quality and a large decrease in childhood emergency room visits and hospitalizations for asthma," amounting to "a 42% decrease in asthma-related emergency room visits" in the inner city.

RPU's support of green power "has been fantastic [for the utility]," says Walters. "I think that with global warming people definitely want to know that their utility is doing what is considered now to be the right thing to do, and that is to transition from traditional energy generation to renewable. I've always felt that that is the question [customers] should be asking their utilities, and if they can talk to you about what you're doing in transition – in an incremental way – then you've got something to talk about."

Advice/lessons learned

Looking back over the ongoing communications with the public during the infrastructure planning sessions and the issues that arose around the coal-fired power plant, Walters says that in hindsight "we would be in less of a reactive mode and be more proactive. It's true that you have to be authentic about wanting to include folks in the dialog. And if I had to do it all over again we would work more intently from a proactive perspective and get people in early to talk about the issue … [of] what we wanted to do with the power plant."

Companies would do well to tie their brands in with green power. "There's a growing number of people who want to know that every organization is doing what's right by the environment. It's not just utilities, but utilities as energy providers are probably at the top of the list. So renewable energy is definitely part of who we are now, and that will grow. No question about it."

SILICON VALLEY POWER

Silicon Valley reaching for 7.5% enrollment in 100% green program

Company profile

Silicon Valley Power is the electric utility of the City of Santa Clara, California. Silicon Valley Power has 144 employees and provides electric service to more than 50,000 customers in a 19-square mile service area.

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Launched in November 2004, Silicon Valley Power's 100% renewable energy program, called Santa Clara Green Power, attracted a 6% enrollment in its first two years. Program leaders expect to see a 7.5% customer uptake in 2007. This participation level is far above the national green pricing program average of 1.2%.

Santa Clara Green Power's strong debut in the green power market drew national recognition for the utility when it was chosen for an EPA/DOE Green Power Leadership Award in December 2006. Silicon Valley Power was the only winner in the New Green Power Program category and is one of only 22 winners of the Green Power Leadership Awards nationwide. The Green Power Leadership Awards program, sponsored by the U.S. Department of Energy and the U.S. Environmental Protection Agency, recognizes individuals, companies and organizations that are making a mark in the advancement of renewable electricity resources.

Although Silicon Valley already has a high amount of renewable energy – about 30% – in its standard generation mix, the green energy program was driven by customers who wanted the option of purchasing 100% renewables. Large customers may purchase green power in blocks, however. According to the utility, Santa Clara Green Power is closely aligned with Silicon Valley Power's energy efficiency programs and its projected power mix of 34% renewable resources in 2007. At this time, the renewable energy sources are about 97.5% wind and 2.5% solar, says program manager Joyce Kinnear. Renewable energy for the program is generated by newly created wind farms and solar photovoltaic facilities in California.

The utility gives credit for the widespread local interest in the program to marketing strategies that help motivate customers to spend a little extra for green power. Another part of the equation is the political climate in northern California, Kinnear observes. "A lot of people are thinking about these issues, and this is a way for them to be part of the solution."

Enrollment costs are attractive as well. Santa Clara Green Power costs customers only 1.5 cents per kWh above the standard electricity rate – one of the lowest green power rates in the country. Proceeds from Santa Clara Green Power support solar projects in highly visible locations, such as schools and city buildings.

The utility reports that a number of high-profile customers have joined the program, including Cisco Systems, Agilent Technologies, Applied Materials, Yahoo!, Santa Clara University and the City of Santa Clara.

Customer interest sparks green offering

Ongoing marketing research with residential and commercial customers had turned up a definite interest in a 100% green energy program. “They had been saying they wanted it for the last couple of surveys before we went with this program,” Kinnear says.

Silicon Valley Power kicked off initial development of the program by sending out an RFP in search of a company that could help develop and bring to market a green energy solution for its customers. The utility chose 3 Phases Energy, San Francisco, a company that serves several other large municipalities in the state. “They contracted with the vendors for the renewable energy certificates and helped us market our program,” Kinnear explains.

3 Phases Energy sells “Green Certificates” that have been certified by the Green-e Renewable Electricity Certification program, which is managed by the nonprofit Center for Resource Solutions. Green certificates ensure that the renewable energy has been strictly monitored to meet the highest green energy standards all the way down the line. “When you see the Green-e logo you know the product is subject to a robust audit each year that accounts for every last megawatt hour of green certificates sold, who sold it, who purchased it, [and] where that energy was generated,” the company says.

Promotions draw response

After developing the program with the help of 3 Phases Energy, Kinnear led the marketing effort, starting with press releases, extensive Web site information and bill inserts that were sent in the first two months of the program. “We also had information in the city’s quarterly newspaper and we met with a number of citizens groups to talk about the program. We have events … such as a Christmas tree lighting … where we provide the information to our customers in a variety of ways,” she says.

The best response rates have come from bangtails on the return reply envelopes. Another good response came from a targeted direct mail campaign developed by a local direct advertising company that uses a proprietary method of determining the best demographic profiles for the program, adds Kinnear. “We do 5,000 mailers to our customers and that’s had about a 2% response rate, which is higher than our bill inserts.”

To reach large customers, “our key customer reps have also gone to our key customers to speak with them individually about the program,” she explains. “They work with industrial customers on the renewable energy front. The renewable energy program helps customers meet some of their climate requirements, particularly if they have work in Europe.”

Kinnear and the key account managers have tried a number of different marketing approaches with commercial and industrial customers. “So far, we find that they respond very similarly to residential customers … but [the smaller commercial customers] seem to respond to the bangtails and some of the bill information better than other venues.”

The participation goal for 2004 was 5%, "which we came very close to at the end of the first year," Kinnear adds. "We've reached 6% of our customer involvement, and for this year [2007] we have a goal of 7.5%." She expects enrollments to level off at about 10% participation in the future.

Ongoing research guides marketing plans

Market research continues in order to ensure that marketing is keeping up with the audience. "We go through very busy periods with a lot of sign-ups … and other periods where we don't get as many sign-ups, so we have to do research and retest different direct mail pieces or bill inserts to see which type of information works better for our customers. For example, we had confusion among some people … about what a renewable energy certificate is, so we are providing that information in an easy to understand, clear format."

The predominant marketing message may vary at times. "We've tried maybe two different bill inserts or direct mail letters to see which has better response. We tried a 'legacy for the future' message and compared that with 'helping the environment.' We found that 'helping the environment' was more effective. We compared that with a 'problem solver' message – because other utilities have found the 'problem solver' message to be more effective – but we did not find that to be the case."

"We tried a 'legacy for the future' message and compared that with 'helping the environment.' We found that 'helping the environment' was more effective. We compared that with a 'problem solver' message – because other utilities have found the 'problem solver' message to be more effective – but we did not find that to be the case."

Silicon Valley Power is now considering rewording its references to green energy. "Based on some information we received from studies at other utilities, marketing 'clean power' as opposed to 'green power' [was more acceptable]. There's quite a bit of research that says that clean power has a much more favorable response. So we're currently looking at that comparison," Kinnear explains.

Making it easy for customers to sign up

Santa Clara Green Energy was offered in response to customer demand, but ferreting out all the customers who have an interest in it requires tenacity. Program leaders know there are many more prospective enrollees out there. "I know that there is pent-up demand in our territory, but people are busy and they don't always read a program brochure at the time they're able to act on it. Our challenge is to find different ways to get our message out to make it easy for them to sign up," states Larry Owens, division manager of customer services. "Renewable energy credits make it very easy to sign up and get 100% green power, because there is not the technical scheduling and all the back office [issues] that go along with other types of renewable products."

Kinnear agrees that creating awareness of Santa Clara Green Power requires continual reinforcement. "There's the continuing challenge of … providing them with the information they need and perhaps doing it in a way that triggers their intention or their thought process so that it's not something they glance at and throw out," she says.

Setting up and administering a new renewable program is not always easy; however, 3 Phases Energy has been a great source of help and support, adds Kinnear. In the day-to-day administration of the program, "the biggest challenge is keeping up with everything on a daily basis," she says. This includes sending out welcome packages to customers, doing the analysis, developing the marketing plan and training customer service reps to keep them current with the program. “It’s not something that you can just set on autopilot. You really need to look at it regularly to make sure it’s fresh, that the information you have is usable and important for people, and that it stays in their short-term memory,” Kinnear states.

UNITED POWER

United Power customers reject green power

Company profile
Brighton, Colo.-based United Power provides electricity to more than 56,000 homes and businesses on Colorado's north central front range. United Power is a founding member of Tri-State Generation and Transmission, a leading regional power supplier.

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United Power, a 56,000-customer co-op in Colorado, has had a variety of issues to deal with regarding the environment and energy usage. First, the utility has found that green power is a hard sell in its service territory, despite its general popularity statewide. Second, new technologies like solar energy or energy storage just aren't there yet or are too expensive to be viable for its members. Third, members embrace energy efficiency rebate programs with gusto.

United Power has worked within the constraints of these converging factors by helping members save on their energy bills using standard but energy efficient electric technologies such as heat pumps, CFLs and geothermal systems, according to United Power marketing and communications coordinator Heidi Storz. In fact, the utility has put its money where its mouth is and, as a demonstration of the energy savings members can realize in their own homes or buildings, is constructing a new $10.5 million headquarters that will employ efficient, environmentally friendly and cost-effective electric systems and technologies.

Amendment 37 and renewable energy at United Power

Colorado's recently passed Amendment 37 requires all larger utilities to provide 10% of their power from renewable energy by 2010. This includes specific types and percentages of energy sources, such as solar power, which must be 4% of the total renewable generation mix. Utilities would receive no credit for renewable energy sources already in place, so United Power's use of hydroelectric power sources for up to 28% of its energy would not count, says marketing and communications coordinator Heidi Storz

After cooperatives petitioned the public service commission to reconsider, the legislature allowed co-ops to poll their memberships to determine if they wanted to be exempt from the renewable energy requirement. At least 25% of members (based on meters) had to vote. United Power communicated all the issues surrounding Amendment 37 to members through its monthly newsletter, which has a 65% readership rate, and direct mail. The utility also conducted an outbound calling campaign urging members to vote. According to Storz, United Power was interested in presenting all the facts and then finding out what the members wanted to do. "We cared very little about how the vote was going to end," she asserts.

Part of the communication effort focused on how the renewable energy requirement would impact a cooperative compared to an investor-owned utility. The not-for-profit co-ops don't qualify for tax breaks on generation sources such as wind power, for example, and would have to use third-party providers to establish new green energy sources. "Those power sources are going to cost us more in the long run," says Storz. "We came out and said, 'Here's what we

FYI

Another factor in the green power program's low participation rate is the amount of renewable hydropower, up to 28%, that is already offered through Tri State and the Western Area Power Administration (WAPA). This has provided a challenge in attracting green power customers.

think the bottom line costs of this program will be to you.' The legislature did say … [that utilities] can only raise residential rates by 1% based on the [amendment]. But where was the other money going to come from?"

The vote took place from October 18 through November 17, 2005, and United Power customers voted in record numbers. More than 13,600 ballots were received, representing more than 18,500 meters, or nearly one-third of the membership. About 79% of these voters chose to exempt United Power from the state mandate. "I had never seen so many ballots come in," says Storz. "I was surprised that the vote was so overwhelmingly against it, because that piece of legislation passed easily in the state."

In the end, the cooperative released a statement which said, in part, "United Power's commitment to renewable energy will continue into the coming decade as the cooperative explores additional resources as part of the future power mix. The vote of members allows United Power to make power purchase decisions based on market conditions rather than state mandates."

Green program attracts few buyers

The resounding "no" vote confirmed to co-op leaders that their members are not in a position to spend more energy dollars. Storz points to the economic situation in the United Power service territory. "We are located in the last growth area in suburban Denver, where you can still buy a house for under $200,000, which is unusual," she explains. She says the co-op's members are stretched financially, and while they probably support the idea of renewable energy, they simply don't have the pocketbooks to support it monetarily as do other communities in Colorado.

Still, United Power offers a green pricing program provided by its power supplier, Tri-State Generation & Transmission. The utility passes the costs through directly and doesn't charge any administrative costs. The program is marketed regularly through brochures and newsletters. "We probably ran it six times last year in our newsletter. Also our new member packet gives them an opportunity to sign up at that time," Storz comments. However, the program has only a small number of participants who have purchased just 300 blocks of 100 kWh each for $2.50.

The Amendment 37 vote provides some insight into the program's low participation rate. "I think that gave us a pretty strong answer. But I don't think we're going to nix the program. We might as well have it there as an option for people that want it," Storz says. Another factor in the green power program's low participation rate, she believes, is the amount of renewable hydropower, up to 28%, that is already offered through Tri State and the Western Area Power Administration (WAPA). This has provided a challenge in attracting green power customers, she says. "The message is that people want to do the right thing; they just don't know how to get there."

But lack of participation is not a problem in United Power's energy efficiency rebate program. "We announce it at the beginning of every year and no matter how much we budget for, we tend to go way over the budget. Installations have been absolutely wild."

Using less energy also is environmentally friendly

As part of its focus on energy efficiency, United Power employs energy management specialists who help customers with their energy needs. Storz points out that one of the energy management specialists has incorporated all the energy-saving electric features in his 3,800-square-foot residence. His highest electric bill has been just $115. “He uses the electro technologies that we’re employing in our new building. He’s not using … solar panels or any of the current ‘sexy’ technologies; he’s just using standard technologies such as a ground-coupled heat pump,” which allows him to take advantage of the utility’s time-of-use rates.

“Heat pumps are, without a doubt,” Storz says, the best standard technology for reducing energy costs. “We don’t rebate air conditioners on our lines right now; we rebate heat pumps,” she adds. “[The United Power service territory] has moderate temperatures much of the time. Any kind of a heat pump will heat during the shoulder temperatures … and people can heat their homes economically with electricity using their heat pumps. We want those on our lines because they run all the time. They can cool their homes in the summer and heat their homes in the winter and do it for a fraction of what they were paying for gas.”

To spur interest in energy efficiency, the utility and its regional wholesale power supplier, Tri-State Generation and Transmission, offer rebates on efficient heat pumps, electric motors and water heaters. United Power offers a $400 rebate to cover the costs of installing a heat pump, and Tri-State also offers a rebate of up to $150 per ton. The combined rebates could amount to as much as $1,150, depending on the size of the heat pump. United Power also offers time-of-use rates, primarily for thermal storage customers.

Some customers living in the Colorado foothills, who previously used propane for heating, “have converted to electricity and have saved themselves a fortune,” Storz comments. “After the item is installed, one of our energy manager specialists will visit the site, check the equipment and make sure it is properly installed, and then [the customers] will receive their rebate on any of the qualifying rebate items.” United Power doesn’t install equipment, but has a list of installers to which it can refer customers.

“I think energy efficiency is probably the most effective way to make a change in the system right now,” Storz reiterates. “I hope we’re on the verge of some real innovation in energy sources. I think that’s what it’s going to take for this to be economical and to help us move forward. But we haven’t seen it. You don’t see innovation in power storage. If they didn’t have enormous tax subsidies for wind power, we couldn’t put it up. They didn’t build any wind power when the subsidies were gone. We have a lot of people that want to go on solar, and Colorado is one of the most cloud-free states in the country. But the payback for solar programs that we’ve priced for these people is 65 years.”

Energy-saving technologies featured in new building

United Power’s new headquarters building is the poster child for what customers can do now to make changes. The utility is promoting the building, on which it broke ground in May 2005, as a working example of how to construct an all-electric home or building using cost-effective technologies that save energy.

After the building's estimated completion date of June 2006, United Power will invite the public to tour the new headquarters and observe the technologies incorporated in the construction.

The 94,000-square-foot, all-electric building is situated on 40 acres and will be 40% larger than the current facility. When completed, it will have 40,000 square feet of office space and 54,000 square feet of warehouse and shop space. Features include occupancy sensors throughout the offices; geothermal heating and cooling technology through 38 pumps and 80 wells; automatic dimmable lighting; and 35 solar tubes to allow natural lighting of the warehouse.

Featuring a variety of technologies, the building was designed to take advantage of the abundance of clear, sunny days in Colorado without going to the expense of installing a photovoltaic system. "We looked at the technologies that are out there that we knew are tried and true and will save money," Storz says.

Regarding the new headquarters building, "we really believe in the technology. We know we'll save money operating our building this way. We're trying to [set an example] every chance we can," Storz adds.

WE ENERGIES

We Energies business customers go green

Company profile

We Energies, Milwaukee, is the trade name of Wisconsin Electric Power Co. and Wisconsin Gas, the principal utility subsidiaries of Wisconsin Energy Corp. Other utility subsidiaries are We Power and Edison Sault Electric Co. We Energies serves more than 1.1 million electric customers in Wisconsin and Michigan's Upper Peninsula and more than one million natural gas customers in Wisconsin. The company also serves about 2,500 water customers in Milwaukee's northern suburbs and 500 steam customers in downtown Milwaukee. The company employs a workforce of 5,200.

Contact

Rick O'Conor
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Richard.oconor@ we-energies.com

Editor's note: This case study was originally published in* Chartwell's Best Practices for Utilities & Energy Companies *in February 2006.

At a time when many utilities have already picked "the low hanging fruit" – having already signed up the customers who are first in line to join green energy programs – they are now seeking ways to reach the more elusive customers who have an interest but need a nudge or two to draw them into renewable energy pricing plans.

We Energies has taken that next step by turning its focus to business customers. The result of this strategy has been a dramatic 30% increase in renewable energy sales from 2004 to 2005. Sales for the utility's Energy for Tomorrow program grew to more than 50 million kWh. The total number of business and residential customers increased from 11,120 in 2004 to 12,140 in 2005.

Another plan to slash rates is in the works, and this should entice an even greater number of customers to switch to green pricing. "We have filed for a decrease in our renewable energy rate from 2.04 cents to 1.37 cents per kWh for our standard rate, and from 1.5 cents to one cent per kWh for our bulk purchase rate, which is for purchases greater than 70,000 kWh per month," states Rick O'Conor, manager of renewable energy. "We would expect any day now that new pricing will go into effect." In addition, a recently developed solar buy-back program is a rate that allows Energy for Tomorrow customers who install photovoltaic systems to sell energy to the utility at the rate of 22.5 cents per kWh. "In this program we buy the solar power, put it in our Energy for Tomorrow program, and then we sell [the customer] renewable energy, which includes solar, wind and biomass. We have already had quite a few sign-ups," says O'Conor, adding that the contract can be filled out online.

The Energy for Tomorrow program, which started in 1996, changed strategies after O'Conor came into the program as manager in 2003. "Previously we had focused on our residential customers for this program. We wanted to reach out to the business customers to see what their interest was in renewables," he says. This outreach initiative was designed for all business customers, from the largest top 200 to the small businesses. As it turned out, the bulk of the new sales came from the largest 200 customers.

The new strategy paid off and brought the total number of business customers in the program to from less than 100 two years ago to more than 400 today, according to O'Conor.

Combining energy efficiency, green pricing works for customers

Marketing was divided into two categories, one for large C&I and one for small business customers. Small business customers were called and sent direct mail pieces explaining the green power program and how they could sign up. "We received a very positive response from calling our small and medium sized businesses. We found significant interest in renewable energy and other energy options," O'Conor reports.

Large business customers were approached one-on-one with individual phone calls and site visits. O'Conor accompanied account managers to meetings with supervisors, managers and company leaders. The We Energies team stressed the customers' needs and interests. Included in the discussions were renewable energy and a range of other energy-saving options, including energy efficiency projects, natural gas vehicles, customer generation, and special rates such as the new solar buy-back program, real-time pricing and other tariffs.

At We Energies, renewable energy and energy efficiency are combined within O'Conor's department, the Office of Energy Options. Presenting these concepts in an attractive package appeals to many business customers. "We tied a lot of our renewable energy programs in with our energy efficiency programs, and that seemed to create a lot of interest and success," he says. "We have some incentive dollars available to help customers improve their energy usage and energy efficiency, so we explain those programs to the customers as well. For a lot of them, it takes a fair amount of time in person or on the phone to explain the program and get them involved."

> "We tied a lot of our renewable energy programs in with our energy efficiency programs, and that seemed to create a lot of interest and success."

Two staff members help support Energy for Tomorrow, which is a significant part of the department's overall focus, "but we sell everything together," O'Conor says.

Offering the programs this way is advantageous for customers. "When I talk to a customer, I'm talking energy efficiency and photovoltaics as well as any other rates they want to talk about from a customer focus," O'Conor asserts. "From the customer's perspective they don't want to talk to multiple parties. They want it to be seamless."

The level of participation for each customer in the program varies from 50 to 100,000 kWh per month. They can sign up for blocks amounts of 25%, 50% or 100% as well as the bulk purchase rates. "We have customers that will just buy 50,000 kWh hours a month. For these large customers, that may only be [a small percentage] of their requirement."

Marketing, educating take many forms

Educating customers and marketing renewable energy can take many forms. Part of informing business customers about renewable energy includes explaining the U.S. Environmental Protection Agency (EPA) Green Power Partnership, which is a voluntary partnership between the EPA and organizations that use green power. Through this program, the EPA supports organizations that are buying or planning to buy green power. We Energies went into the companies armed with the specific requirements for them to qualify for the program and even filled out the EPA forms for them.

In return for their participation, businesses are listed on the We Energies Web site as participants in the Energy for Tomorrow program. The site also provides links to these businesses. Businesses purchasing more than 5,000 kWh a month are designated as partners, and those buying more than 50,000 kWh a month are known as leaders.

Additionally, “we include them in our newsletter that goes out to all our renewable energy customers,” says O’Conor. “We’ve done a number of articles as well as an annual ad in the Milwaukee Journal Sentinel.” Businesses receive promotions from We Energies and of course they are free to promote their participation in their own marketing efforts.

The 30% increase in sales for 2005 showed that the new marketing strategy paid off. “We were certainly pleasantly surprised with the response,” O’Conor states. With new programs coming up, including the low-cost pricing plan, the utility is bound to attract even more interest in the program.

Approval for the new rates is expected, says company spokesman Barry McNulty. “The public service commission is looking for utilities to have the ability to provide lower-cost options at a time when increased fuel costs are driving [energy costs],” he says. “It certainly gives us another marketing piece that enables us to go out there and get customers enthused and excited about renewable energy.”

“The public service commission is looking for utilities to have the ability to provide lower-cost options at a time when increased fuel costs are driving [energy costs].”

XCEL ENERGY

Customer-sited solar generation eclipses $7.7 million in payouts

Company profile

Xcel Energy, based in Minneapolis, is an electricity and natural gas company with operations in eight states. Xcel Energy provides energy-related products and services to 3.3 million electricity customers and 1.8 million natural gas customers through its regulated operating companies. Xcel Energy's Colorado operating company is Public Service Co. of Colorado.

Contact

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Tom.henley@xcelenergy.com

Editor's note: This case study was originally published in* Chartwell's Best Practices for Utilities & Energy Companies *in March 2007.

Colorado voters made their preference for more renewable energy clear when they passed Amendment 37 in November 2004. Under this law, large utilities must provide more renewable energy resources in their generation mixes and at least 10% of electric retail sales by 2015. As the largest utility in the state, Xcel Energy is taking the lead in developing renewable energy sources and providing programs to support residential and commercial installations of photovoltaic systems.

The law mandates that the utility use specific percentages of generation sources within the generation mix. "At least 4% of [the 10% required] has to come from solar and half of that has to be customer-sited [generation]. That essentially means about 18 MW in 2010," but due to high customer response "we feel we'll be above that," reports Xcel Energy spokesman Tom Henley. Currently about 2 MW of solar generation sources are now established on the customer side, he reports.

Solar programs have proven to be popular. Customers are lining up to take advantage of rebates through one of Xcel Energy's solar programs – Solar Rewards. This program has now eclipsed the $7.7 million mark in payouts since its launch in March 2006.

Solar Rewards is designed primarily for residential or small commercial customers and pays out rebates to those who have installed 0.5 kW to 10 kW systems anytime after Dec. 1, 2005. Through an onsite application, Xcel Energy will rebate customers $2 per watt of solar panels installed on qualified customer premises. Under another solar program, Renewable Energy Credit (REC) – which was closed after the utility received 653 applications and paid out 586 – Xcel Energy purchased RECs generated by customer systems for up to $2.50 per watt. Designed for solar power units from 0.5 kW to 10 kW, the REC payment was available to anyone within the state – Xcel Energy customer or not – and the installation did not have to take place after Dec. 1, 2005, says Henley.

Customers also receive up to $2.50 for each watt of power the facility is proposed to produce. "That is for the renewable energy credits, which are associated with that [level of] energy, and it's a one-time payment," reports Henley.

With these combined payments, customers with small installations can receive up to $4.50 per watt upfront. For example, if a small system was 6 kW and cost $30,000 to install, the customer would receive between $12,000 and $14,000 in rebate payments and renewable energy credits. They also are eligible for a federal tax break of around $2,000. "They would end up being close to paying for half of the portion of the entire system," Henley explains.

Xcel Energy is just rolling out a new category within Solar Rewards for medium-sized facilities from 10 kW to 100 kW. In this aspect of the program, customers also receive $2 per watt installed; but, their energy usage payout will be based on a 20-year contract for the actual energy that is produced. Under this plan, they will be paid $115 per MWh per month. This program will remain in the testing stage for about a year and then be reassessed.

The first-year Solar Rewards budget was $20 million, which covered everything from marketing to working with the solar providers, including SunEdison, the company that is building a solar plant for Xcel Energy. SunEdison's 8 MW facility in the San Luis Valley "is not necessarily considered part of Solar Rewards; it's part of the overall solar program," he explains. This facility will be the largest photovoltaic (PV) central solar power plant in the United States, located in an area with the best solar conditions in Colorado, according to the National Renewable Energy Laboratory. SunEdison will build, own and operate the central solar power plant in south central Colorado. Half of the 4% solar mandate has to come from customer-sited and customer-owned facilities; the SunEdison facility will fall into that category.

The plant is expected to be online by the end of 2007. Xcel Energy's operating company, Public Service Company of Colorado, will purchase the power and the renewable energy credits associated with the plant.

In still another area, Xcel Energy is still sorting through proposals from RFPs the utility sent out to larger independent solar power providers with 100 kW to 2 MW units. These proposals total more than 26 MW, notes Henley.

FYI

If a small system was 6 kW and cost $30,000 to install, the customer would receive between $12,000 and $14,000 in rebate payments and renewable energy credits. They also are eligible for a federal tax break of around $2,000.

Marketing seeks to keep the message simple

Marketing for Solar Rewards has been extensive. Leading the marketing efforts is product portfolio manager Julia Gauthier. Although this was a highly complicated and technical topic, "we tried very hard to keep the initial message simple," Gauthier states. The strategy was "to get people's attention and then steer them toward the resources to learn what would be best for their homes or businesses. We have mainly kept it to the simple message that the program will pay nearly half the cost, and then we send customers to the Web site www.xcelenergy.com/solar for more information."

Program administration, which includes marketing and other costs, was limited to 10% of total program expenses. "To prepare for the March 2006 launch, the program was introduced in January with a Web site, bill insert and emails to subscribers of an email update list." Xcel Energy participated in the Solar 2006 trade show and customer workshops and the utility was a sponsor of Boulder Solar Week.

At the same time, the utility issued press releases, "resulting in lots of news coverage," Gauthier says "We also had a 'first check' ceremony in May 2006 that generated local TV news coverage, and [Channel] 9 News did a special story during sweeps week in November 2006."

Results of the promotional campaign were excellent. "The program had over 1,200 applications in 2006, which was double what we thought might occur, although it was hard to have any expectations," she adds.

Future marketing plans include more of the same – customer workshops, trade shows, bill inserts, press releases, solar week participation and ongoing Internet information.

Gauthier points out that Xcel Energy was not alone in marketing the program. “Local installers of PV systems play a huge role in promoting the program. They are literally our indirect sales force. With everything Xcel Energy has done to promote the program, installers are doing twice as much,” she reports.

The most effective marketing channels have been press coverage and installer sales channel activity, Gauthier adds. “Workshops also are effective because they allow real communication and sharing of technical, detailed information that people have to understand to really make a decision. It is a much smaller audience, but these are the most serious customers.”

Gauthier gives credit for much of the solar program’s success to customers’ interest in renewable energy. “There was pent-up demand when the program launched, and the interest continues today as people see how successful the program is and as installers are out in the field talking to customers about PV. Xcel Energy has also provided a comprehensive, easy to use online application process. We see addresses of neighbors in groups all over our service territory.”

Solar system technology running smoothly

Both the small and medium-sized solar facilities are equipped with net metering. The medium-sized facilities also will have a solar power production meter, Henley says. The net meter spins backwards “when the power is being produced and fed back into the grid,” Henley explains.

“At the end of the year, there’s kind of a true-up period. If the customer has put more power into the grid than they’ve used, the customer would receive a rebate check from us. That fee would be based upon the amount it would have cost us on a normal everyday basis to purchase that energy during the times when they were feeding back into the grid. It’s a cost-average type of fee.”

In the Sun Edison program, “approximately 1.2 MW will come from concentrating photovoltaic units. The concentrated solar photovoltaic unit is going to be the largest of its type in the nation. The remaining approximately 6.8 MW of generation will be advanced flat-plate solar panel units,” says Henley.

There have been no grid connection issues because “the inspection process and the application process are pretty detailed and arduous for customers involved in this,” he adds. “First of all, we have to make sure that the systems are appropriately tied into our grid and that they’re compatible with what we already have. Second, for safety purposes we make sure that these systems are responsive enough to shut off if an outage should occur in a particular area, so when our people are working on an outage they won’t get back-fed and get electrically shocked or worse.”

The solar program has been successful all around, but a source of pride for Xcel Energy is the company’s ability to actually lower program costs below the approved threshold.

Originally the law was set at 50 cents for each customer, to be drawn from a renewable energy standard adjustment on customers' bills, Henley states. "The legislature amended that in 2005, because 50 cents per customer is not going to cover the cost of solar power. It became 1% of the customer's electric bill for the renewable energy standard adjustment. Since the program began, we've been operating on only 0.6%, and we've been able to fulfill the obligations to this point."

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Appendix D

TERASEN GAS PRIMARY RESEARCH STUDY

RFP:P091794GRW - Green Gas Study

Quantitative Proposal

Date September 18, 2009
R1547/MA/GK

Presented to:
Terasen Gas Inc.

infocanada@tns-global.com
www.tns-global.com

Contents

At TNS, we know that being successful in today's dynamic global environment requires more understanding, clearer direction and greater certainty than ever before. While accurate information is the foundation of our business, we focus our expertise, services and resources to give you greater insight into your customers' behavior and needs.

Our integrated, consultative approach reveals answers beyond the obvious, so you understand what is happening today – and what will happen tomorrow. That is what sets TNS apart.

Thank you for allowing us to explore your business needs. The comprehensive program that follows is designed to help you achieve your goals. We hope you will trust TNS to provide the insight you need to sharpen your competitive edge.

1.0 Form Of Proposal

1. REFEERENCE:		**P091794GRW**	
PROJECT:		Green Gas Study	
CLOSING TIME:		Friday, September 18th, 2009	
		12:01 PT (Pacific Time)	
		Proposals are irrevocable and open for acceptance by Terasen for a period of sixty (60) calendar days from the Closing Time.	
NAME OF BIDDER:		TNS Canadian Facts	
ADDRESS:		610-1140 West Pender Street,	
		Vancouver, BC V6E 4G1	
PHONE:	(604) 668-3344	FAX:	(604) 668-3333
GST Number:	137057352	BCSST Number:	N/A

2. PRICING REQUIREMENTS GST and BCSST (If applicable) included in prices below:

Proposal pricing to include GST only.

Cost to perform study within the timelines.

If multiple scenarios are proposed then provide pricing for each scenario. Outline any contractors against each scenario.

Scenario 1: $ 21,000 with N=800

Scenario 2: $23,100 with N=1,000

Scenario 3: $25,200 with N=1,200

Please refer to page 20 for more information on pricing.

A. Bidder’s Qualifications

The Bidder shall submit the following information. If the Bidder is a joint-venture or limited partnership, all information required shall be submitted for each participant in the joint-venture or limited partnership.

1. Name	TNS Canadian Facts
2. Incorporated, Partnership or Sole Owner	Incorporated
3. Date of Incorporation or Partnership	November 17, 1993
4. Registered Address	610-1140 West Pender Street, Vancouver, BC V6E 4G1
5. Subsidiary Of:	WPP Group plc
6. If bid bond requested by Terasen name and address of bonding company if a certified cheque and not a bid bind is submitted with the Proposal.	N/A

7. The Bidder’s Workers’ Compensation Board (“WCB”) information is as follows:

7.1 WCB Experience Ranking System (ERA)

Previous 3 years	N/A

7.2 WCB Inspection Report Summary

Previous 3 years	N/A

B. Subcontractor’s Information

There will be no subcontracting on this project.

C. Bidder’s References

The Bidder shall list three (3) references from Work of similar nature to this Project which it has recently completed or is now conducting.

Reference	Work Description	Phone Number
Eddie Van Dam BC Hydro	Manager, Research Services	(604) 623-4536
Shashi Maharaj (alternate) BC Hydro/Power Smart	Power Smart Evaluator	(604) 453-6316
Marshal Wilmot Rogers Plus	Vice President, Marketing	(604) 644-1027
Nancy Norris BCTC	Policy Analyst	(604) 699-7463

Please refer to page 26 for more information about the projects that were done.

3. The bidder agrees that all work shall be performed in accordance with the Workers' Compensation Act of the Province of British Columbia; the Bidder's Workers' Compensation Board Registration Number is C124722476.

4. In the event that Terasen issues any addenda please acknowledge receipt below:

Addendum#	Date Received
N/A	

5. This section MUST be completed for the Bidder's Proposal to be considered.

5.1 We confirm that we accept in their entirety the terms and conditions in Part 4 of the *RFP: Green Gas Study / Reference: P091794GRW* and agree to be bound by them.

5.2 The Bidder must check on of the boxes below as appropriate:

- ☑ We accept the Scope of Work described in Part 2 of the *RFP: Green Gas Study / Reference: P091794GRW.*
- ❑ We accept the Scope of Work described in Part 2 of the *RFP: Green Gas Study / Reference: P091794GRW* with the following specific exceptions:

7. In Witness Whereof the Bidder has executed this Proposal the 18 day of September, 2009.

Authorized Signatory	Authorized Signatory
Dr. Michael Antecol	Gerry Keane
Print name	Print name
Vice President	Research Director
Title	Title

2.0 Corporate Information

2.1 Principal Contact

The principal contact and liaison person for this study will be:

Dr. Michael Antecol

Vice President

1140 West Pender Street, Suite 610

Vancouver, British Columbia, V6E 4G1

Tel. 604-668-3306

2.2 Location Of Head Office And Support Offices For TNS Canadian Facts

TNS Canadian Facts Inc.

Toronto (Head Office)
900 – 9 Bloor Street East
Toronto, Ontario, M4W 3H8
Tel: 416.924.5751
Fax: 416.923.7085

Vancouver
1140 West Pender Street, Suite 610
Vancouver, British Columbia, V6E 4G1
Tel: 604.668.3344
Fax: 604.668.3333

Montreal
1250, rue Guy, Bureau 1030
Montreal, QC, H3H 2T4
Tel: (514) 935-7666
Fax: (514) 935-6770

Ottawa
55 Murray Street, Suite 210
Ottawa, Ontario, K1N 5M3
Tel: (613) 230-4408
Fax: (613) 232-7102

2.3 Corporate History And Size Of Organization

TNS Canadian Facts is one of Canada's largest marketing and social research firms. Our roots go back to 1932 when Canadian Facts was established as the country's first survey research organization. Today, we have offices in Toronto, Montreal, Ottawa and Vancouver, with 170 full-time members of staff.

We are a TNS company[1], the world's largest custom marketing research firm and the world's largest provider of Internet-based custom marketing research. We provide market research measurement, analysis and insight in more than 110 countries.

Over our long corporate history, our primary activity has remained the same: the conduct of research investigations to provide our public and private sector clients with information and strategic direction.

1 TNS Canadian Facts has been a part of TNS plc since 2003. TNS plc has been part of The Kantar Group since October, 2008.

Marketing and opinion research has grown dramatically in Canada since 1932. Throughout the years, we remained committed to the needs of our clients and dedicated to the development of progressive research systems. Allied to expert client service, the company offers a comprehensive range of research services, technical expertise and specialized facilities, catering to the broadest spectrum of research needs.

Toronto is the head office and control centre for data collection, sampling, quality control and data processing departments. TNS Canadian Facts, Vancouver, offers knowledge and expertise to clients interested in western markets. The Montreal office is completely bilingual and provides specialized expertise to clients interested in the French-Canadian market. The Ottawa office provides specialized assistance on assignments for the federal government. The company was incorporated in the Province of Ontario on November 17, 1993—Provincial Charter No. 1052289.

An overview of our history in Canada is depicted in the diagram to follow.

1930s	1940s	1950s	1960s	1970s	1980s	1990s	2000s
• Company founded, 1932 • Field force established, 1937	• Establishment of Montreal office, 1948 • First national probability sample, 1948	• First omnibus survey - The Big 8M/CF Monitor, 1956 • Canadian Family Opinion - national mail panel, 1960	• Consumer Opinion Centres - mail interview facilities, 1964 • First in-computer facilities, 1964 • Establishment of Vancouver office, 1965	• Merger with Stevenson Kellogg, 1973 • Establishment of Ottawa office, 1974	• Integration of ABT Associates of Canada, 1986 • Installation of CF FACTS Network, 1986	• Integration of Burke I.R., 1991 • Formation of CF Group Inc., 1993 • Part of NFO Worldwide Inc., 1998	• Part of IPG, 2000 • Part of TNS, 2003 • Part of WPP 2008

2.4 Parent Company: TNS plc

Who we are:

- World's largest custom research business
- Second largest global market intelligence company
- Global network spanning over 80 countries
- Operating in 110 countries worldwide
- Over 14,000 employees
- Over $1.85 (US) billion in 2006
- Listed on the London Stock Exchange (TNS.L)
- Global leader in customer stakeholder management research
- Global leader in opinion polling and social research
- World's largest consumer panel research group

TNS is one of the world's leading market information groups, providing market measurement, analysis and insight through its operating companies in 80 countries. Working with national and multinational organizations, we help our clients develop effective business strategies and enhance relationships with their customers.

TNS provides full-service, primary market research. Our mission is to become our clients' sixth sense of business™ by giving them a deeper understanding of their customers' behavior, better anticipation of their actions and greater insight into what they really want. We use an integrated, consultative approach to get beyond the obvious and design a comprehensive plan that meets our clients' needs now and in the future.

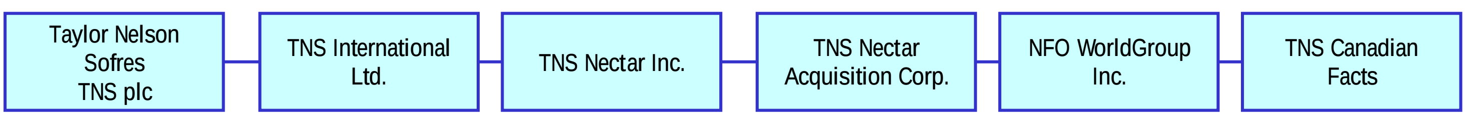
TNS plc has office locations in over 80 countries, as depicted in the map to follow:

An overview of the corporate profile for TNS plc is as follows:

- The 1960s saw the creation of five of the market research companies that are at the heart of the Taylor Nelson Sofres (TNS) Group today:
  - Intersearch in the USA in 1960
  - AGB in the UK in 1962
  - Sofres in France in 1963
  - Frank Small Associates in Australia in 1965
  - Taylor Nelson in the UK in 1965
- But the very first seeds have been sown in the USA in 1946, when NFO (National Family Opinion) opened for business.

- In the 60s, 70s and 80s, all these companies grew significantly, introducing a wide and increasingly sophisticated range of research solutions and using the latest technological developments. And as their clients grew, they started to create their international networks.
- Key developments:
    - Sofres opened offices in six European countries, the US and 12 countries in Asia Pacific.
    - Taylor Nelson and AGB each developed a UK network of offices and began to acquire businesses in Europe.
    - NFO grew to become the by-word for managed access panels in the USA.
    - It soon became clear that brands were becoming global, and brand owners would need global market information partners. In the 1990s, the market research industry started to consolidate, as major clients demanded an increasingly international service.
- NFO made a series of acquisitions around the world and the companies that now form TNS responded to the changing market by joining forces, enabling them to deliver consistently high quality services to customers around the world.
    - Sofres acquired Secodip (1992)
    - Taylor Nelson joined with AGB (1992)
    - Sofres combined with FSA (1995)
    - Sofres acquired Intersearch (1997)
    - Taylor Nelson AGB and Sofres merged (1997)
    - TNS acquired NFO (2003)

The corporate legal structure of TNS plc is depicted in the following diagram:



The address for the head office of TNS plc is:

- **Head Office**
  TNS House
  Westgate
  London, England W5 1UA
  Tel: +44 (0) 208 967 4551

2.5 Core Competencies

TNS recognizes that our clients need a partner with world-class expertise and innovative thinking in specialist areas of research. We have responded to that demand by positioning our custom business to meet these needs, within the following areas of expertise:

- **Product Development And Innovation**

  Product development and innovation services help clients identify new opportunities, evaluate whether an idea justifies investment, discover how to make a concept more appealing, optimize the product mix and forecast potential sales volumes often using tools such as Discrete Choice Modelling (DCM). It covers the product development process from idea generation, early stage screening, concept and product optimization through to volumetric forecasting and post-launch evaluation.

- **Customer Satisfaction / Stakeholder Management**

  Stakeholder management helps clients measure and monitor their performance and relationships with various stakeholder groups. Clients are particularly interested in understanding factors affecting levels of satisfaction, retention and motivation of customers and employees. TRI*M™, the main TNS solution in this area, offers actionable recommendations to boards and senior management teams.

- **Brand And Communications**

  Brand and communications services help clients build their brands through every stage of the brand experience, from development to implementation of strategy. TNS also tracks the success of brands and communications in the marketplace, with a view to optimizing brand performance and maximizing future potential.

- **Retail And Shopper Insights**

  Retail and shopper provides insight about in-store and shopper behaviour for manufacturers and retailers. These insights can be used to improve equity, sales and profitability of a brand or category through merchandising, store layout, pricing and promotions, as well as in-store communications.

- **Customer Intelligence**

  Customer intelligence provides insight based on analysis of multiple data sets, combining behavioural information at an individual or household level. This delivers insight about our client's customers in areas such as customer profitability, defection risk and propensity to buy. Fusing this with TNS information such as usage and attitudes can then be used to drive more tailored marketing.

Our areas of expertise include, but are not limited to:

- Consumer Panels
- Interactive Surveys
- Stakeholder Management
- Polling And Social
- Finance
- Technology
- Segmentation And Positioning
- Media
- Consumer
- Brand And Advertising Research
- Healthcare
- Energy And Conservation
- Automotive
- New Product Development
- TV & Radio

2.6 Location Of Offices For Project Team Members

The project team members proposed for this project are all based in our Vancouver office. We are supported by our operations departments in Toronto, and can draw support from other offices in Canada, or internationally as required. Telephone interviewing, if any, would be conducted from TNS Call Centres located in London (ON), Montreal (QU) or Bathurst (NB).

3.0 Experience And Expertise

3.1 TNS Canadian Facts Understands The Canadian Energy Sector

To follow are some examples of work that we have done in this sector within the past three years, including projects with Terasen Gas:

Terasen Gas – Alternative Energy Interviews (2009)

TNS Canadian Facts conducted 14 in-depth interviews about alternative energies across BC. This project assessed overall awareness of and interest in the use of such energy.

BC Hydro Power Smart Focus Groups (2009)

TNS Canadian Facts conducted 5 focus groups with BC Hydro customers who subscribed to the Team Power Smart program. In an effort to spread an energy efficiency ethic throughout BC using word-of-mouth, BC Hydro created the Power Smart Ambassador program. The focus groups explored how potential Power Smart Ambassadors responded to the program concept and general public reactions to the program concept.

BC Hydro Customer Satisfaction Survey (2009)

TNS undertakes an annual large-scale tracking survey for BC Hydro in British Columbia. The customer satisfaction survey runs for 52 weeks of the year and surveys over 5,800 customers, both residential and business. The reports provided by TNS include the key benchmarks used by the Board of Directors to monitor satisfaction among a population of over 1.5 million customers.

In addition to collecting data and producing the key performance reports, TNS provides analysis and interpretation on a quarterly basis, to assist the company in its C-Sat strategy.

Union Gas (1987 to present)

Annual Residential Market Share Tracking research is conducted among Union Gas' residential customers. 1,400 telephone interviews are conducted across Ontario with quotas by region. For many years the deliverables included a full written report and data. Currently the client handles its own reporting. Each year the survey evolves to address new areas of interest, while retaining key tracking metrics.

Consumer DSM Post-Advertising Measure (2008)

BC Hydro commissioned TNS Canadian Facts to conduct a post-advertising measure for the "Join Team Power Smart" advertising campaign. A total of 524 online interviews were conducted among British Columbia residents aged 18 years or over to determine awareness of the ads, and impact on energy conservation attitudes and behaviours.

Qualitative Study with Psychographic Segmentation of BC Hydro Customers (2008)

Focus groups were conducted to understand in greater depth how various customer segments think about and use electricity, and how they might be persuaded to use less of it. Conducting these focus groups also allowed these segments to be qualitatively validated and compared. A total of 53 BC Hydro customers participated in these groups, which were moderated by Linda Dethman.

Challenge Focus Groups (2008)

In July and August 2008, we conducted six focus groups for BC Hydro to gather opinions and experiences from participants in two behavioral change challenges targeted to local governments. The results of the study were used to guide future initiatives targeted to local government stakeholders. The groups included 30 representatives from local governments, and were moderated by Linda Dethman.

Smart Metering (2008)

Six focus groups among BC Hydro's residential customers were done to assess perceptions and reactions to various aspects of the "Smart Meter Infrastructure" (SMI) Program roll-out. The first four groups were conducted in-person at a professional focus group facility in Vancouver and included customers from the Greater Vancouver area. The second two sessions were on-line groups, where the moderator and participants communicate via the Internet. This approach allowed wider geographic coverage, and customers from diverse locations such as Bella Coola, Victoria, and Quesnel participated. The focus groups were co-moderated by Linda Dethman with Marina Gilson.

Corporate Satisfaction and Image Study (2004 to present)

A corporate satisfaction and image study is conducted annually by telephone with BCTC's key stakeholder groups, including provincial government officials, municipal representatives, and customers. Additionally, the TNS online panel was used to poll public stakeholders. In total, 1,375 interviews are conducted per wave. Separate sets of recommendations were made for each stakeholder group to provide strategic direction for improved performance and perceptions among each of the groups.

Terasen Gas Corporate Image Study (2004/2006/2008)

In order to develop a strategy to manage its corporate image, Terasen Gas retained TNS Canadian Facts to conduct a customer satisfaction and brand equity study with its key stakeholders. This study takes place on a two-year cycle. This study surveys 850 Terasen customers and 60 ‘influencers’: elected and administrative provincial / municipal government officials. The study is fielded via telephone. Through TRI*M and Conversion Model analyses, the study identifies specific areas of focus and communication strategies for improving corporate image.

Terasen Gas Ad Tracking (2007/2008)

In 2007 and 2008, TNS Canadian Facts undertook a continuous advertising tracking study for Terasen Gas to measure the effectiveness of an extensive radio and tv campaign. In addition to measuring key ad metrics through telephone interviews, the survey investigated householders’ attitudes and perceptions towards home energy sources and natural gas in particular. The study was the key benchmark used by the British Columbia Utilities Commission in measuring the effectiveness of communications about the de-regulation of the natural gas industry in British Columbia.

Large Industrial DSM Initiative (2007)

Telephone interviews were conducted among large industrial customers of a major Canadian natural gas utility servicing northern, southwestern and eastern Ontario to assess awareness and participation in an energy program. The survey included awareness of various specific energy programs, energy efficiency targets and payback period. The factors leading to program participation were also determined.

Annual Residential Market Share Tracking (1987 to present)

Research is conducted among residential customers of a major Canadian natural gas utility servicing northern, southwestern and eastern Ontario. Each wave consists of 1,400 telephone interviews conducted across Ontario with quotas by region. Each year the survey evolves to address new areas of interest, while retaining key tracking metrics.

3.2 TNS Canadian Facts Understands Discrete Choice Modelling:

These are some examples of work that we have done using the Discrete Choice Model in the past three years:

New Conjoint Study (2009)

Rogers Plus was facing competitive pressures from a direct competitor who aggressively lowered their prices while extending their rental durations on new releases. To understand how the competitors latest offer would impact switching behaviour among movie renters, a market study was undertaken with customers of both chains. A discrete choice modelling exercise was conducted to understand what offerings movie renters value most, at what price point and how our client should proceed in response to their competition's new offering. A total of 2,395 online interviews were conducted with movie renters at each major chain and among those that might rent elsewhere (e.g., independent movie rental stores).

Work Place of the Future (2009)

TNS Canadian Facts helped a major financial institution look at what their future physical workplace might look like if innovations were given an in-depth exploration. The workplace improvements that were examined would potentially positively affect employee work-life balance, productivity, engagement and turnover. The study explored eight different aspects of a physical workplace and featured a Discrete Choice Model that defined the workplace features most important to associates. TNS Canadian Facts administered an online survey with banking associates from two urban regions in mid June of 2009. Of the 1,437 surveys that were completed, the breakdown was 1,041 by Corporate employees (+/- 1.7% margin of error, nineteen times out of 20) and 396 by Branch employees (+/- 4.1% margin of error, nineteen times out of 20).

Video Brand Survey (2008)

Rogers Plus commissioned TNS Canadian Facts to conduct an online survey to determine the awareness level of its new rental program among its customers and non-customers. A discrete choice model was also part of the study to come up with a share of preference simulation for all movie rental package elements and pricing levels. Separate share of preference simulations have been produced for Rogers Plus customers and Rogers Plus non-customers, as these two groups tend to be differ in their opinions.

4.0 Project Methodology & Management

4.1 Moving Toward Smart Research: Our Guiding Principle

Currently, Terasen Gas (TG) primary business activity involves the delivery of natural gas and piped propane to homes and businesses throughout British Columbia. Indeed, 95% of natural gas customers in the province receive their gas via TG. But, at least two major changes are afoot in the energy sector: (1) the energy marketplace is becoming increasingly competitive and (2) environmental issues are increasing in importance among both the public and TG customers. As a result, TG is repositioning itself as a diverse energy solutions provider that can be both competitive as well as environmentally friendly (i.e., by minimizing the environmental impacts of its activities).

It is from this perspective that TG has issued RFP P091794GRW (the "RFP"). Specifically, one of the avenues that TG is exploring is the provision of a *Green Gas* program among residential customers whereby TG would "transform" biogas produced from landfill, waste treatment plants, cow manure and other organic waste products into pipeline quality natural gas for distribution to its customers. At the same time, TG is also developing biomethane supply, creating offset projects and building a full-scale green product offering.

The purpose of the above-mentioned RFP is straightforward from one perspective: *Terasen would like to better understand the potential market for green gas, its market drivers and other factors affecting different price points.* Successfully doing so will help TG to satisfy several of its Environmental Commitments, namely:

1. Integrating environmental protection measures into all elements of its business;

2. Using resources efficiently and effectively;

3. Setting targets and objectives for environmental performance; and,

4. Incorporating … environmental performance measures into its corporate goals, objectives and employee compensation systems.

There is no doubt that TNS Canadian Facts can perform the tasks pursuant to this RFP that will allow TG to follow through on the above-mentioned objective and commitments. At a certain level, though, if that was all we did, we would be nothing more than a data provider that follows instructions and communicates in a timely manner. But, it is clear from the RFP that TG desires more than a mere order-taker in a research supplier.

It is TG's planned use of the data that moves this RFP from straightforward data collection and analysis to a more complex and rigorous project – one that requires a research supplier to be a consultant, to add value, to determine the WIM (What It Means) of the data. That planned use is:

> *Findings from the study will help the project team determine the appropriate product offerings by identifying the right customer segment(s), factors affecting their decision making and the right pricing*.

It is here that TNS Canadian Facts can offer much more to TG and add value to the project: we can offer *Smart Research*. We implement *Smart Research* by taking a consultative approach to business issues that require market research. By diving deep into our clients' issues we can not only deploy the full range of business solutions at our disposal, but, more importantly, we can pick the right solutions, or combination of solution, for each particular situation. We will do the same, when successful in this bid, with TG.

4.2 *Smart Research* And Terasen Gas: The Recommended Approach

Above, we introduced the concept of *Smart Research* – our guiding principle. Here, we provide a roadmap on how to implement such a research project for TG. The first step in moving in this direction, is to understand the specific objectives of this study:

1. Determine the market interest;
2. Determine the potential target market and market size;
3. Develop clear and concise customer profile(s);
4. Determine market drivers;
5. Determine price points and factors affecting price points; and
6. Understand customer perceptions on different product offerings (i.e., offsets, biomethane).

From our point of view, it is important to uncover the answers to the above points from both TG customers and non-customers. Developing this new business line may require a two-sided strategy – (1) increasing spend among current customers for environmentally-friendly alternatives and (2) converting over non-customers to TG.

However, the ultimate solution may be even more complicated: *commitment* to the environment may be an important overriding factor. We need to know what drives those who are *committed* and those who are *uncommitted*. Why? Because those who are committed to the environment, whether current TG customers or not, are likely the best targets for this project. Conversely, those who are uncommitted will probably not be swayed, meaning any advertising dollars targeting this group would represent resources poorly spent. More on this will be covered later in the discussion on Conversion Model™ (Section 4.2.2).

4.2.1 Meeting The Objectives – Regression And Discrete Choice Modelling

There are two main ways to determine market size, target market, market interest, perceptions of product offerings and key drivers: directly or indirectly. Specifically,

1. We can directly ask respondents what is important to them to understand their attitudes, their interest, and the amount they might be willing to pay for a *Green Gas* product. After the data has been collected, we would conduct advanced statistical procedures such as OLS multiple regression to determine which elements are (or would be), in fact, the drivers of *Green Gas* uptake.

2. We can take an indirect approach; that is, we can have respondents conduct a discrete choice modelling exercise – a trade-off analysis – to ascertain the key drivers and price points.

We propose to do both and compare/triangulate the results.

The reason for doing both is simple: when individuals are asked scaled importance questions (e.g., how important is the environment?), there is a strong chance that many will be rated as “very important” (or, as an 8, 9 or 10 on a 10-point importance scale). Indeed, if a question is important enough to be included in the survey, it is very likely that the respondents will also find it to be important to them. **But this leads to a problem: if everything is reported to be important at the univariate level, it becomes difficult to create the final *Green Gas* product and the ancillary marketing**. In addition, these questions are all asked independently, theoretically without connection to any other questions. It is because of these facts that post-facto regressions need to be run — this procedure puts all relevant variables into the hopper at the same time in an attempt to determine the ultimate drivers.

Further, pricing is difficult to measure as a straight-up question because it can only be measured for one product or one combination of products at a time. Since the actual product could take many forms, these straight-up pricing questions – while important to ask, at least at a general level – would have to be repeated for each possibility.

To get around these issues, we would employ Discrete Choice Modelling (DCM) to help determine the optimum characteristics of such a product as well as the optimum price under different condition. TNS Canadian Facts has used DCM for a number of years to assist our clients with key marketing decisions. Indeed, TNS Canadian Facts has an extensive background in applying DCM across a wide range of respondent-types, sectors, product categories, brands and in various jurisdictions. Our Statistics Group made up of professional statisticians who are experienced in applying this analysis technique in several forms of data collection. One caveat: DCM can only realistically be done in an online survey, a point to which we will return later.

In DCM, as proposed here, respondents are asked to choose between a series of alternatives that trade-off on different features. From their choices, we are able to understand which elements weigh more heavily on their selections, and under which conditions. From this, a simulation model is built that is based on a trade-off analysis of different choice sets. This model would take into consideration various elements associated with the *Green Gas* product.

Specifically, respondents will be presented with a range of packages in a series of “choice” scenarios which are created by varying attributes, such as type of gas, offsets, availability of infrastructure and price. For each scenario, respondents answer a simple question related to two possible choices:

If these were all the choices available, which would you choose, if any?

Importantly, respondents are also allowed to choose “none”. Once the respondent finishes with one scenario, he/she moves to the next choice scenario and makes the same simple decision. This data is then analyzed via modelling and market simulation. The results of this analysis will then establish customers’ preferences and the optimal offering. (NOTE: Once the optimal offering has been chosen, we often recommend conducting a focus group to assist in marketing execution. Ideally, the groups will explore potential positive “triggers” for the package that could be used in a marketing campaign).

Because of the “choice” nature of the task, it is critical to design and present the components of the *packages* in the most efficient way, not only for the respondents but for the subsequent analysis. With DCM studies, the challenge is to present clear choices for respondents, while not reducing the number of options to being so small that all critical features cannot be individually evaluated in the analysis. As a starting point, we offer the following attributes (in bold) and levels (placed under the attributes) for consideration:

Type of Gas
- Traditional natural gas
- Biogas from landfill
- Biogas from water treatment
- Biogas from cow manure/organic waste

Infrastructure to Collect And Distribute the Gas
- Built / in place
- Needs to be built

Price of Gas

Same as current price
5% more than current price
10% more than current price
15% more than current price

Offsets

No
Yes – $1
Yes – $2
Yes – $3

With these attributes and levels, it is possible to envision choice sets such as the following:

	Choice 1	**Choice 2**	
Type of Gas	Biogas from landfill	Biogas from cow manure/organic waste	
Infrastructure	Needs to be built	In place	NONE
Price of Gas	10% more than current price	5% more than current price	
Offsets	No	Yes — $2	
	☐	☐	☐

We will work closely with Terasen Gas to identify the proper attributes and levels for testing. The focus will be to design a streamlined set where the elements are comprised of those that need to be "traded-off."

There are two other considerations. First, a flaw of many DCM studies is their desire to obtain full factorial measurement from too small a respondent population. This results in undue respondent burden as they have to go through many choice sets. **Solution**: have a large respondent pool. Second, as mentioned above, a DCM study has to be conducted online (it can be done in person but that would be cost-prohibitive). This means that one needs to consider the number of options that can be presented on each "screen" in the online environment: it is important that respondents see competing options on a single screen. **Solution**: we believe that two choices with a none option, as presented above, is appropriate.

Finally, see Appendix for an example of DCM.

4.2.2 Adding More Depth: Conversion Model™

Using regression and DCM we will be able to determine, directly and indirectly, the market size, target market, market interest, perceptions of product offerings and, most importantly, the key drivers of *Green Gas* uptake. However, we believe that we need to refine those results further due to the fact that TG will ultimately have to engage in both advertising and marketing to spur uptake. So, instead of gearing a campaign toward the natural gas market in its entirety, we recommend that those campaigns be geared to those consumers who are *STRONGLY OR SOMEWHAT COMMITTED* to the environment (whether or not they are currently natural gas customers or not) **AS OPPOSED TO** those consumers who are *STRONGLY OR SOMEWHAT UNCOMMITTED* to the environment. It does not make sense to market/advertise to the uncommitted as there would be relatively little uptake among that segment. It is clearly more important from an advertising and marketing point of view to look at the regression and DCM findings of those who are committed to the environment (although it is still important to investigate the uncommitted).

Accordingly, we need to identify the different levels of environmental enthusiasts (via commitment). To do this, we recommend using Conversion Model™ to measure levels of commitment for the environmental position. It should be noted that Conversion Model™:

- Is the leading commitment measure with over 8,800 studies conducted worldwide to date;
- Is used by 80% of the largest brands in the world;
- Predicts "next brand purchase" correctly 91% of the time; and,
- Tracks market share with a 90% correlation.

Using Conversion Model™ will yield the above-mentioned segments (strongly committed and somewhat committed to the environment, and strongly uncommitted and somewhat uncommitted to the environment). These segments will then be used to add more depth to the regression and DCM results.

4.2.3 Profiling

Once we have determined the possible segments, via the regression-based driver analysis and the DCM, as refined by Conversion Model™, we will profile those segments using demographic and other relevant criteria. This will be extremely helpful to the marketing and advertising efforts related to any proposed *Green Gas* program.

4.2.4 Alternative Consideration: Pre-Post Test

This research can also be structured to include a pre- and post-measure in order to test the effects of any upcoming advertising campaign on *Green Gas* uptake, market share, environmental commitment, etc… In the post-measure, we do not need to replicate the entire study. A smaller scale survey could be conducted that includes only the necessary measures. The benefit of at least considering this option is that TG would effectively be setting up a natural experiment regarding the effectiveness of its potential advertising campaign. This is important as experiments are truly the only way to show causation – that is, did the campaign work, or, what elements of the campaign worked.

<u>However, the quotation provided in this proposal accounts for only a one-time study to provide Terasen Gas with the strategic knowledge that it needs to develop a targeted and effective advertising campaign. We would be happy to revise the quotation if Terasen Gas would like to include the follow-up post-test study.</u>

4.3 Project Methodology

4.3.1 Research Design

As set out above, in order to conduct the DCM, the project has to be conducted online. As a result, what follows is our methodology for conducting such an online study.

4.3.2 Sample Size And Sampling

As we discussed at the outset, it would be instructive to include natural gas customers as well as non-customers. For that reason, we propose sampling the general household population (and asking them if they are current natural gas customers or not) in British Columbia.

We will use TNS's online panel in Canada. The research will be both targeted (i.e., to British Columbia) and cost effective as online surveys are more cost effective than other data collection methods. Note that TNS will offer panelists who qualify for our standard sweepstakes points.

We recommend at least 800 interviews across the province, although more would be preferred. A quota design will be implemented to ensure an appropriate number of interviews (based on population) are conducted in each part of the province. In contrast, there will not be a quota on natural gas customers vs. non-customers. Rather, we will weight the results at the end to ensure that the proper ratio is achieved (see Weighting Section, below).

Note that it would have been possible to sample from TG's customer lists (at least for natural gas customers); however, because TG does not maintain email records, this was not an option.

4.3.3 Questionnaire Development

We propose an online survey that will take no more than 15 minutes to complete. The content of the questionnaire will include the topics that have been discussed above. We will consult closely with you at the start of the study to confirm the objectives and gain a more detailed understanding of your program ideas for the first draft the questionnaire. After all, that's *Smart Research*.

4.3.4 Pre-Test

The survey will be pre-tested with approximately 5 to 10 respondents prior to a full launch. Following the pre-test, we will thoroughly de-brief with our operations staff to obtain their input on potential improvements to the questionnaire, and will discuss the outcomes with you. The questionnaire will then be modified as necessary.

4.3.5 Coding

Traditional coding and editing is required only for open-ended questions. Code lists for open-ended questions will be handled with particular sensitivity to ensure that the outcome is optimal with regard to diagnostics, within each of responding groups (e.g., customers vs. non-customers).

4.3.6 Weighting Procedure

Our weighting function is supported by full-time specialist staff including people with high-level qualifications in statistical data analysis. In combination, the staff, databases, software and hardware provide a sophisticated and reliable service to TNS Canadian Facts' clients.

4.3.7 Data Processing And Analysis

The data processing will be performed using our powerful in-house computing facilities. Although we will consult with you closely throughout the entire study, this is especially important during the analytical phase, when the detailed plan for analysis is being developed and implemented.

We will produce cross-tabulated detailed tables, using variables determined in conjunction with you. The regression based key driver analysis will be undertaken at the end of the data collection phase. Likewise, the DCM will also be conducted at that point. Conversion Model™ segments will be used in both sets of analysis.

4.3.8 *Deliverables*

We will deliver the following to TG:

1. Research study plan.
2. Final report that includes an executive summary, detailed review of findings, with clear and actionable recommendations AND a separate **WHAT IT MEANS** section.
3. The DCM simulator.
4. Cross-tabulation tables.
5. Dataset in SPSS or Excel.
6. Presentation.

4.3.9 *Schedule*

The following schedule provides a rough timeline for completing this survey.

Project Milestone	Date
Start-up Meeting and Questionnaire Design	2 weeks (starting w/o Oct. 5)
Questionnaire Setup	1 week (starting w/o Oct. 19)
Data Collection	1 week (starting w/o Oct. 26)
Data Cleaning, Coding, Data Processing	2 weeks (starting w/o Nov.2)
Conversion Model™, Regression and DCM Analysis	2 weeks (starting w/o Nov. 16)
Draft Report (delivered by Dec 18, 2010)	3 weeks (starting w/o Nov. 30)
Final Report And Presentation	No Later than Jan. 31, 2010

We will work with TG to make any necessary changes to the proposed timeline upon contract award.

4.4 Price

The price to conduct the study as set out above and within the timeline, with 800 completes is $20,000 + GST or $21,000 Total.

As mentioned, it would be preferable to have more completes. Accordingly, we are providing two other options with larger sample sizes:

- With 1,000 completes, the price is $22,000 + GST or $23,100 Total.
- With 1,200 completes the price is $24,000 + GST or $25,200 Total.

Note that we are charging for extra completes at cost.

4.5 Other Project Management Issues

4.5.1 TG And The BC Utilities Commission

We recognize that to move forward, TG will have to make its case to, and get approval from, the BC Utilities Commission (BCUC). We will work hand-in-hand with TG to ensure that approval is obtained. We are also prepared to make presentations to the BCUC if that is what the Commission requires.

We are familiar with that process as we went through the same procedure with BCTC.

4.5.2 Capacity

At the time of proposal submission, TNS Canadian Facts has the resources and individuals available to undertake this study under the parameters and timeframes outlined in our proposal.

As one of the largest marketing research companies in the world, we have the personnel and resources to quickly and efficiently handle any unforeseen circumstances, and ensure that our commitments to our clients are met. The project at hand requires primarily the resources of a small number of individuals. Should it be necessary, alternate personnel will be available to complete this assignment; our team in Canada includes many senior consultants with experience in the energy sector, including Brook Tyler (Research Director, Toronto) and Moira Silcox (VP, Senior Research Advisor, Vancouver), as well as numerous client service representatives who will assume responsibility for this project if required.

If for any reason, we find that we cannot meet our obligations using our in-house resources, alternative arrangements will be made, and this will be fully disclosed to, and agreed by, TG.

4.5.3 Team Accountability

Members of the project team for this project are all dedicated individuals who take their responsibilities to their clients very seriously. And, we are working in a corporate environment in which we are strongly encouraged to satisfy our clients and fulfill our obligations. Our business depends on this orientation, and we take pride in the service that we provide to our clients. We fully appreciate that future assignments are fully dependent on the good will that we engender with our current clientele.

4.5.4 Issues And Risk Management

TNS Canadian Facts has a comprehensive business interruption plan in place. In the event of a disruptive event, a client service team in another location will be identified, and will draw on back-up files which are stored in secure locations. Should a project team member become unavailable for any reason, another individual, with equal or superior qualifications will be assigned to meet our responsibilities to our clients.

Should a disruptive event adversely impact our Canadian operations, we will draw on our global resources to meet our clients' expectations and our contractual obligations. For example, in the case of an unanticipated event that interrupts our data processing centre, one of our other data processing teams in another country, such as India or Korea, will be called upon to do the data processing.

5.0 Project Team And Qualifications

5.1 Client Service

We value our relationship with Terasen Gas, and demonstrate its importance to us by providing the highest level of competence, responsive service, and bringing creativity and enthusiasm to our work with members of Terasen Gas staff. In addition to being respectful, courteous and professional, we are committed to providing thought leadership, in part, by our thorough understanding of your business issues and the environment in which you operate.

TNS Canadian Facts has a disciplined approach to project management as we believe it is key to ensuring client research needs are met. All projects are designed, analyzed and reported by senior professionals (typically at the vice president or director level). Studies are managed day to day by researchers with a minimum of three years of direct project management experience (typically five years or more) and under the supervision of the senior researcher in charge of the project. Fieldwork and all of the data processing functions are managed by individuals with many years of experience within their highly specialized areas of expertise. TNS Canadian Facts has its own sampling and statistical analysis departments, both of which are managed by our head statistician, a vice president with more than 25 years of experience in applied statistics.

The senior professional client service team members will consult with Terasen Gas researchers to develop a full understanding of the research needs and objectives. This discussion will focus on communications issues and desired business outcomes ***not*** on research issues *per se*. The intention is to design a study firmly grounded to the business case. It is *Smart Research*.

We bring cutting edge and innovative thinking, in part, by our application of our proprietary business solutions. We network internally with our global colleagues to maintain a current knowledge of new research techniques, and do not hesitate to present new ideas to our clients that can contribute to the utility of the research. In many cases we bring our clients together by sharing findings and providing benchmarks for clients who operate in the same sector.

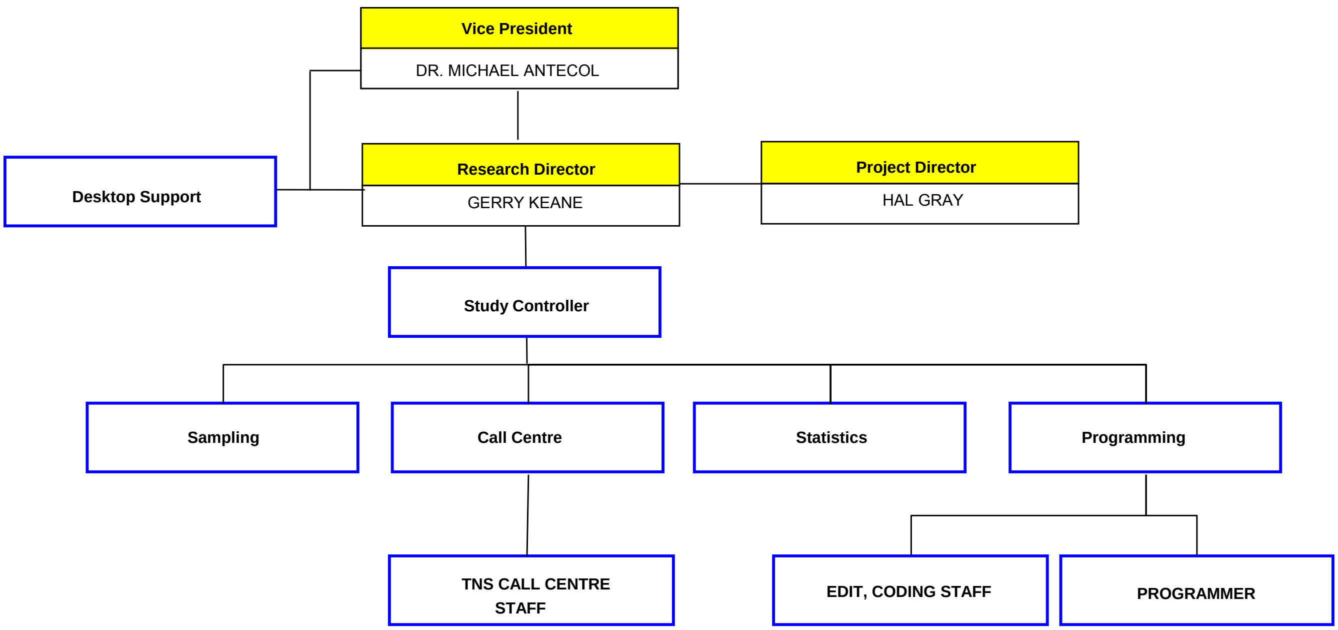
We are fully accountable to our clients for quality and service delivery. The individual team members are committed and dedicated. In the event of unforeseen circumstances, alternate staff members, with equal of better qualifications will be immediately identified and will step in to complete the assignment.

Our commitment to integrity, our vast resources and quality control procedures virtually eliminate service delivery deficiencies. Should this occur, we take immediate steps to rectify the situation to meet both our contractual obligations and to satisfy our client’s needs. Our business is built on our reputation, and we distinguish ourselves from our competitors by providing a consistently high standard of work and service.

5.2 Your Project Team

The proposed team for this project is comprised of experienced and committed professionals who will provide outstanding, flexible and innovative consulting services to Terasen Gas in conducting this research. Members of the team have a range of backgrounds, skill-sets and are recognized as leaders in their fields. This, backed by the substantial resources of TNS, will insure full success of the project.

Organizational Chart of the Project Team



To follow are the roles and qualifications of the key members of the project management team.

Dr. Michael Antecol, Vice President, Vancouver

Dr. Michael Antecol will directly oversee this study, with a particular emphasis on design and interpretation.

Vice President of TNS Canadian Facts, and head of its Vancouver office. Michael has both in-depth and practical experience in quantitative and qualitative methodologies and has over 11 years of direct market research experience working with major clients in the US and Canada. A synopsis of Michael's credentials and experience in the marketing research industry is given below.

AT TNS, Michael oversees all activities in the Vancouver office. Prior to joining TNS, Michael was a Vice President at POLLARA (2004-2006), where he focused on media research, particularly local TV news. Other areas of research practice included general TV studies, marketing, social marketing and advertising, young consumers, technology, and telecommunications. Clients included some of Canada's largest companies and major commercial organizations in the western market. *Of particular interest here, Michael oversaw Terasen Gas' residential customer satisfaction research as well as builder satisfaction research. He also oversaw various BC Hydro projects.*

From 2002 to 2004, Michael was Director of Online Research at Frank N. Magid Associates, an international media research company. In combination with traditional telephone research, he applied online methodologies to help clients (such as Belo Corp., Cox Communication, Emmis Broadcasting, and Young Broadcasting in particular) effectively produce local TV news programs. The goal of these studies was to determine consumer attitudes and behaviors to local TV news, understand media consumption habits, develop compelling TV and online content, construct successful marketing and advertising campaigns, driving traffic from local TV newscasts to the station's websites and vice versa, and proof new media concepts. Michael played a critical role in presenting findings to senior management and suggesting recommendations for change. His work is credited for stimulating improved audience ratings for many of his clients.

Michael's studies from his time at Magid have been quoted in various media outlets including Broadcasting & Cable, Christian Science Monitor, MSNBC News, ChronWatch.com, Poynter Online, and the Toronto Star. Some of the research findings have also been presented in speeches to the Bureau of Broadcast Measurement (BBM) Canada and the Television Bureau of Advertising (TVB), and a keynote speech to the predecessor of the Market Research Intelligence Association.

Prior to these appointments, Michael held the position of Young Consumer Analyst at Forrester Research (2000-2002) where he investigated the use of technology in the formulation of marketing strategies directed at young consumers.

In terms of his academic career, Michael completed a B.A. in Political Science at York University and a LL.B. from Osgoode Hall Law School. He then attended the Graduate School of Journalism at the University of Western Ontario where he completed an M.A. in Journalism. He then continued on with his studies and completed a Ph.D. in the School of Journalism at the University of Missouri. Following this, Michael completed a Post-Doctoral Fellowship at Stanford University, receiving independent funding from the California Tobacco-Related Disease Research Program for a project that investigated the effects of advertising as it pertains to anti-smoking campaigns.

Michael's academic research has been widely published in journals such as the Canadian Journal of Communication, Mass Communication & Society, Newspaper Research Journal and Political Communication. Abstracts can be found in various Proceedings of the American Academy of Advertising and Psychophysiology. He has also presented numerous papers to the Association for Education in Journalism and Mass Communication (AEJMC), International Communication Association, the American Academy of Advertising, the Society for Psycho-physiological Research, and the Society for Research on Nicotine and Tobacco. His research has earned several awards including membership in the Kappa Tau Alpha Honor Society and a "Top Three Research Paper" in the Communication and Theory Division of AEJMC.

Michael has also taught graduate-level courses in media research methods at the University of Missouri School of Journalism. He is a member of the Market Research Intelligence Association.

Gerry Keane, Research Director, Vancouver

Gerry will be your key contact working closely with you on this project.

Gerry Keane joined TNS-Canadian Fact recently, complementing his 18 years experience in marketing research. Gerry is and experienced qualitative research who has conducted over 800 focus group and in-depth interviews over his career. He has worked on both client-side and consulting sides but always within marketing research. Prior experience includes program evaluation experience particularly on demand-side management programs for BC Hydro (Power Smart). He also created and oversaw the research program that led to the rebranding of Vancity Savings Credit Union. Gerry also brings extensive experience in brand development and tracking brand awareness. As a skilled project manager, Gerry has a knack for isolating key findings and interpreting them into strategic understanding.

Gerry holds a Bachelor of Arts (Psych.) from the University of Alberta and is a Certified Market Research Professional (CMRP). He is also a member in good standing with the MRIA.

Hal Gray, Project Director, Vancouver

Hal Gray will be responsible for many of the day-to-day tasks involved in the study setup, data collection and data processing of results. He will be project managing the Key Accounts survey.

Hal has worked directly in market research developing project needs analysis and implementation, delivery, monitoring, reporting and evaluation of those projects for the last five years. He has either coordinated or assisted in several longitudinal studies for a social agency, and has directed long-term, quarterly, customer satisfaction studies for major corporations such as a telephone company, and a BC utility. As well, he has coordinated and reported on dozens of custom studies and 50 plus focus groups.

Hal has a background in marketing, promotion and advertising campaigns, events, ideas and programs both in the public and private areas. For many years, Hal held an executive position in the non-profit sector and, as well, a coordinating and teaching position in the post-secondary field.

He has ten years' experience in stakeholder outreach and partnership building in the public and non-profit sectors. Hal has over twenty years experience as a freelance writer and editor in commercial print, audio, video and film and is an award-winning fiction and screenplay writer.

Hal is a member of the Market Research and Intelligence Association. He is a past board member of the Canadian Periodical Publishers Association.

6.0 References

In the following section, we present three (and one alternate) references and case studies to demonstrate our experience in delivering similar projects and providing insightful recommendations.

1. BC Hydro

BC Hydro strives to enhance their approach to measuring the “health of their relationships” with all stakeholders who can materially impact the success of their enterprise. TNS was commissioned to do an annual large-scale tracking customer satisfaction survey for BC Hydro in British Columbia. The reports provided by TNS include the key benchmarks used by the Board of Directors to monitor satisfaction among a population of over 1.5 million customers.

In addition to collecting data and producing the key performance reports, TNS provides analysis and interpretation on a quarterly basis, to assist the company in its customer satisfaction strategy.

Eddie Van Dam
Manager, Research Services
BC Hydro
Tel: (604) 623-4536
e-mail: edward.vandam@bchydro.com

Alternate

TNS conducted a series of focus groups on a new Power Smart initiative. Gerry Keane conducted six focus groups around BC gauging public response to the concept. The discussion followed overall response to the idea as well as generating ideas on how the program would be delivered and promoted.

Shashi Maharaj
Power Smart Evaluator
BC Hydro/Power Smart
Tel : (604) 453-6316
e-mail: eshashi.maharaj@bchydro.com

2. Rogers Plus

Rogers Plus was facing competitive pressures from a direct competitor who aggressively lowered their prices while extending their rental durations on new releases. To understand how the competitors latest offer would impact switching behaviour among movie renters, a market study was undertaken with customers of both chains. A discrete choice modelling analysis was conducted to understand what offerings movie renters value most and how our client should proceed in response to their competition's new offering.

TNS provided a customized share of preference market simulator that Rogers Plus could manipulate the different scenarios to somehow predict the impact on market share of one offering versus another.

Marshal Wilmot
Vice President, Marketing
Rogers Plus
Tel: (604) 644-1027
e-mail: marshall.wilmot@rci.rogers.com

3. British Columbia Transmission Corporation

As a Crown corporation, BCTC's stakeholders include provincial and municipal officials, residents of BC, commercial electricity transmission customers, Independent Power Producers, wholesale electricity providers and industrial customers. BCTC requires an overall view of its stakeholders' impressions along with an understanding of the factors that drive their satisfaction to make operational improvements and introduce initiatives that better meet the needs of its stakeholders. To obtain the views of their stakeholders, BCTC has engaged TNS for the past four years. Multiple data collection methodologies are used, as different channels are more effective with different stakeholder groups.

Key performance metrics collected in this study are reported to the Provincial Government every year. We go as far is rolling these metrics into a single index statistic for BCTC's management team to monitor. Note that this index has been independently audited by KPMG and deemed a valid measure for BCTC's corporate scorecard.

Following this, a roadmap is provided within the research for each stakeholder group. This custom analysis identifies the key priorities BCTC need to address immediately versus longer term. This roadmap is constructed by factoring in BCTC's strengths and weaknesses along with an open multivariate, correlational analyses of what is most important for each stakeholder group.

Nancy Norris
Policy Analyst
BCTC
Tel: (604) 699-7463
e-mail: nancy.norris@bctc.com

7.0 Freedom Of Information And Protection Of Privacy Act

7.1 Overview Of Privacy Compliance

TNS Canadian Facts is a global leader among marketing research firms in compliance with Privacy regulations and legislation within British Columbia, in Canada and in all jurisdictions within which TNS plc operates.

TNS Canadian Facts is proud of its role in leading the marketing research industry on privacy compliance. We were the first survey research firm in Canada to appoint a privacy officer and develop a corporate privacy policy with PIPEDA in mind, more than a year before the law took effect. Our vice president of public affairs, David Stark, chaired a privacy committee of the Marketing Research and Intelligence Association (MRIA) in 2003 and 2004 and he co-authored the association's comprehensive Privacy Protection Handbook. David is also the current president of MRIA.

TNS Canadian Facts is a Gold Seal member of the MRIA, an organization that sets industry standards to which member companies must adhere, and which protect respondents' privacy. Gold Seal members are reviewed biennially for compliance with the MRIA's standards of conduct. An arm's length professional accounting firm with expertise in carrying our quality assurance audits undertakes the standards reviews. In addition, all surveys that we conduct are registered with the MRIA's Survey Registration System. A toll-free telephone number to the MRIA enables respondents to check whether surveys they have been asked to complete are legitimate.

TNS Canadian Facts has implemented numerous practices, policies and procedures to ensure compliance with PIPEDA and protect respondents' privacy:

- Training about PIPEDA's requirements and other privacy laws is conducted regularly with our staff, from interviewers and study controllers to programmers and client service staff.

- Client companies that provide customer lists to our firm for research sample must first enter into a personal information protection agreement (PIPA) with TNS Canadian Facts. Among its many provisions, the agreement gives each party the right to audit the other's information management practices. We have a template PIPA that we use with clients; however, we are happy to review and work with agreements initiated by our clients.

- Before receiving a customer list supplied by a client, we review our client's privacy policy to ensure that it has obtained sufficient consent to be able to disclose its customers' personal information to us.

- Before fieldwork on telephone studies commences, we conduct a thorough briefing with our interviews assigned to the study. We review scripts with them, any privacy considerations, how to respond appropriately to individuals' questions about the survey, and how to handle our clients' unique and specific requirements.

- We maintain our own Do-Not-Contact list of telephone numbers belonging to households who have told us that they do not want to participate in survey research conducted by our firm. We respect individuals' desire not to be contacted without question. All random digit dialling (RDD) and client-supplied samples are screened against our DNC list to ensure that no one is contacted against their wishes.

- We identify ourselves and state the purpose of our contact with prospective survey respondents. For telephone surveys, we proudly display our name and phone number on telephones equipped with caller I.D. When we invite individuals to participate in our surveys, we assure them that their survey responses are treated in strict confidence and that no personally identifiable information is disclosed to other parties.

- For clients who would like to be able to analyze respondent-level data strictly for research purposes, we advocate that a statement to that effect be included in the questionnaire and that we obtain respondents' express permission for the disclosure and use of their survey responses.

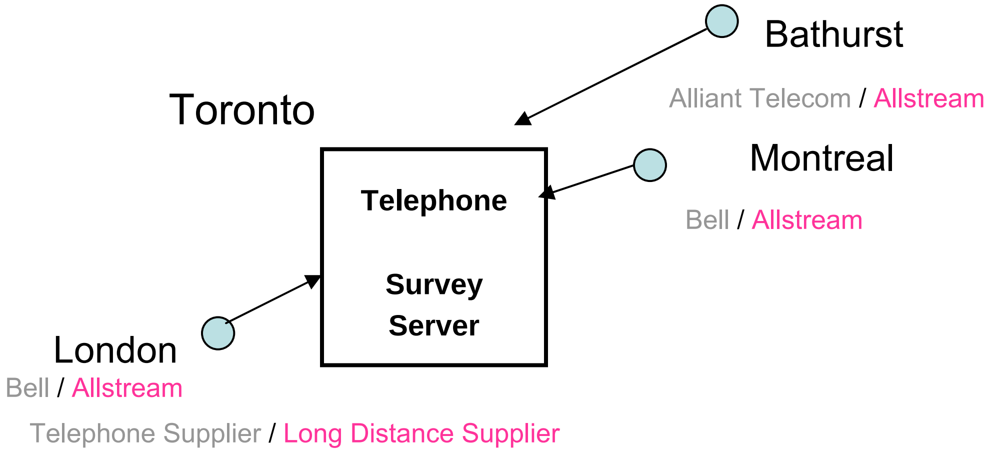
- Identifying information about respondents (i.e., name, address, phone number, etc.) is destroyed as soon as it is no longer needed. The destruction and retention timetable depends on the circumstances of a given project. Longitudinal or tracking studies typically require a longer retention period. In many cases, however, information is kept long enough to allow for the possibility of re-contacting respondents to validate their responses. For most studies, identifying information is destroyed within three months. Many clients require destruction of their customers' contact information immediately upon completion of a study, which we are happy to accommodate.

- We employ technological, physical and organizational security measures to safeguard the personal information we collect, such as the use of firewalls, passwords, controlled-entry into our offices, locks on doors and filing cabinets, and limiting employees' access to personal information on a need-to-know basis. Further, all of our employees are contractually bound to respect client confidentiality and the confidentiality of personal information.

- We are open with our privacy policies and practices. Our privacy policy is accessible from every page on our Web site. Our privacy policy and online data collection practices have been independently reviewed and certified by TRUSTe, an organization that helps consumers and businesses identify trustworthy online organizations through its Web Privacy Seal, Email Privacy Seal and Trusted Download Programs.

7.2 Our Proposed Solution Is Fully Compliant

All aspects of our proposed study design will fully comply with privacy regulations in BC and in Canada. For telephone surveys, call routing will not leave Canada, at any time or for any reason. The details of our telephone interviewing data collection system, and disclosure of our telephone and long distance suppliers are detailed in the diagram following.



Further, all personally identifiable information for surveys conducted via all data collection methodologies remains housed on our servers in Canada, and the data cannot be accessed from outside of Canada. Our servers are housed at our Toronto head office in a locked facility with access limited to those who require it. The server facility is protected by 24-7 building security and CCTV surveillance cameras. We also have a very comprehensive emergency response business continuity and disaster recovery plan in place.

We have reviewed the requirements of FOIPPA with our Privacy Officer and legal counsel. Our solution is fully compliant:

	Yes	No
A) Proposed solution is fully compliant with provisions of FOIPPA	☑	
B) Proposed solution requires some modification(s) to comply with the provisions of FOIPPA. (Details as clearly as possible the modifications anticipated, and confirm that all costs associated with those modifications would be borne by the Proponent).		☑
C) Proposed solution is not currently compliant with the FOIPPA and may require significant modifications to comply with the provisions of FOIPPA. (Detail as clearly as possible the modifications anticipated, and confirm that all costs associated with those modifications would be borne by the Proponent).		☑

We are confident an independent evaluation of our solution’s compliance with FOIPPA by Terasen Gas will result in the conclusion that our solution is entirely compliant, and we welcome this review.

Appendix

Our Approach

A DISCRETE CHOICE MODELING EXAMPLE

In this and the following pages, we present a small hotel DCM case study to illustrate the steps that we would apply in using DCM, recognizing that the most important step in the process is to “build” the packages to be tested. The following shows one of the DCM choice screens in the survey:

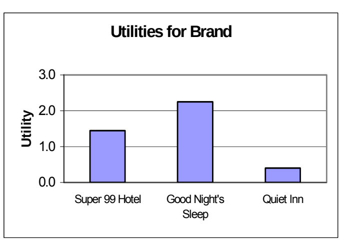
“If you were considering staying at a hotel and these were the only alternatives, which one of the following hotels would you choose to stay in?”

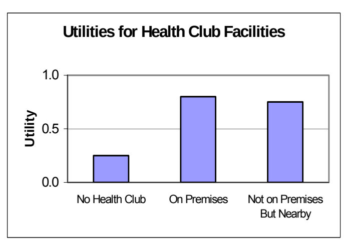
	(1) Super 99 Hotel	(2) Good Night’s Sleep Hotel	(3) Quiet Inn
Price	$90.00 plus taxes	$110.00 plus taxes	$110.00 plus taxes
Location	Near the Airport, Away From Downtown	Downtown	Downtown
Room	Basic Room, Not Cramped But Little Workspace	Large and Spacious with Desk and Table	Large and Spacious with Desk and Table
Health Club Facilities	No Health Club Associated With Hotel	On Premises	Not on Premises But Nearby
Restaurant in Hotel	No, But Restaurants Nearby	Yes	Yes

Additional screens would show different price points and options. Using this approach, DCM has several benefits. It poses a realistic and natural task for the survey respondents. Instead of rating or ranking the choices, the respondent simply makes a purchase decision. Also, packages can be customized to match marketplace reality. Every package does not need to share all of the same attributes or attribute levels. The DCM approach also has the option of allowing respondents to choose a “none” option. By selecting that option, a respondent can contribute information about the decrease in demand to be expected if all of the products are considered unattractive.

Our Approach (cont’d)

After the survey data have been statistically analysed, utility charts can be constructed to show the levels of the attributes that are the most preferred, holding all other attributes constant. The following are examples of utility charts in this hotel case study.





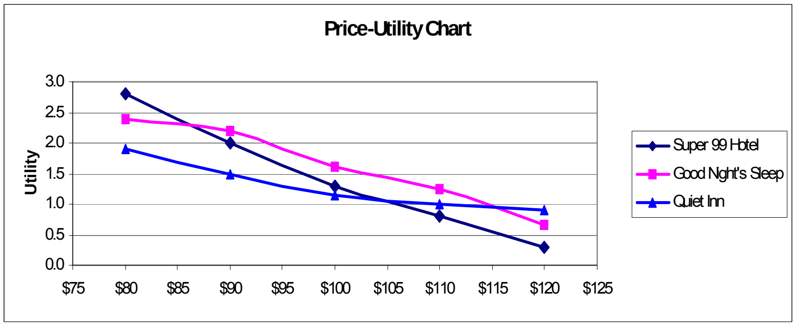
The “brand” utility chart shows that Good Night’s Sleep is the most preferred lodging, followed by Super 99 Hotel. Quiet Inn is the least preferred.

The “health club facilities” chart on the right shows that, when holding all of the other attributes constant, having health care facilities is preferred over having facilities nearby, which is preferred over having no facilities at all. However, the utility difference between having facilities on the premises and nearby is very small, suggesting that consumers place little importance on whether the facilities are on the premises or nearby.

The actual numerical value of the utilities has no meaning; what is important is whether the value is higher or lower than the other utility values on the same chart.

Our Approach (cont'd)

To illustrate the effect of changing one component of the video rental package over another, we use price in our example. The price of the product or service is frequently a major component of any purchase decision. Also, it is erroneous to assume that the "brand" or package type has no effect on price sensitivity. For instance, consumers may be more receptive to a steeper price of a familiar brand than a less popular, even niche brand. DCM has the flexibility to model an individual price utility curve for each brand (or video rental package). Below is an example of a price utility chart.



In this example, the preferred hotel, when all three are at the $80 price point is Super 99 Hotel, followed by Good Night's Sleep and then Quiet Inn. However, there is a different story at the $90 price point - Good Night's Sleep is now the first choice, followed by Super 99 Hotel and then Quiet Inn. If Good Night's Sleep increases to $100, but the other two hotels remain at $90, Super 99 Hotel would then become the most preferred (with a utility value of 2.0). However, Good Night's Sleep would still be preferred over Quiet Inn (the utility of Good Night's Sleep at $100 is about 1.6 and the utility of Quiet Inn at $90 is 1.5). In the analysis, the key is the hotel's utility value in relation to that of the other hotels.

Our Approach (cont'd)

SHARE OF PREFERENCE MARKET SIMULATOR

A share of preference market simulator is used to assess how people's preferences might be affected by changes in package attributes.

In the first scenario, all three hotels are offering rooms at the $90 rate. Super 99 Hotel and Good Night's Sleep have their location attribute set to the Downtown level, and Quiet Inn has the attribute set to the Near the Airport, Away From Downtown level. The rest of the attribute levels are set to the levels desired for this particular marketplace scenario.

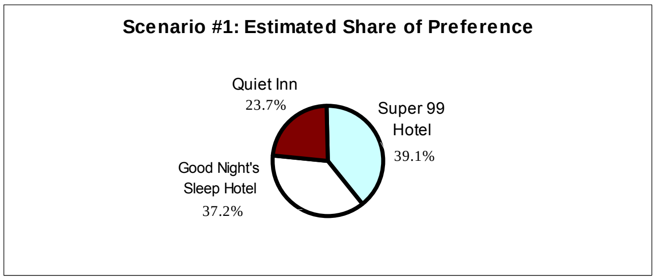
INPUT SCREEN

SCENARIO #1 Inputs

	Super 99 Hotel	Good Night's Sleep Hotel	Quiet Inn
Price	$90.00	$90.00	$90.00
Location	Downtown	Downtown	Near the Airport, Away From Downtown
Room	Basic Room, Not Cramped But Little Workspace	Large and Spacious With Desk and Table	Large and Spacious With Desk and Table
Health Club Facilities	On Premises	Not on Premises But Nearby	No Health Club
Restaurant in Hotel	No, But Restaurants Nearby	No Restaurants in Hotel or Nearby	Yes

Our Approach (cont'd)

Running the market simulator, the output shows that Super 99 Hotel has the largest estimated share of preference among the three hotels at 39.1%, followed by Good Night's Sleep at 37.2% and then Quiet Inn at 23.7%.

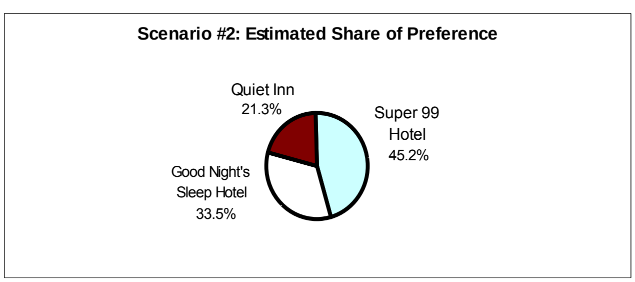


Now, suppose that Super 99 Hotel were considering adding a restaurant to its hotel, but in doing so it would need to increase its room rate …

Our Approach (cont'd)

In Scenario #2, the attribute level for Restaurant in Hotel is changed to Yes and the price is changed to $95. All other attribute levels have been kept the same as in the first case.

Looking at the results of the market simulator below, the restaurant addition and rate increase would be a reasonable course of action. The estimated share of preference among the three hotels in Scenario #2 is Super 99 Hotel at 45.2%, followed by Good Night's Sleep at 33.5% and then Quiet Inn at 21.3%. From these simulations, we can see that, for the Super 99 Hotel, the utility increase associated with the addition of the restaurant outweighs the utility decrease that occurs because of the room rate increase, resulting in a net increase in utility for Super 99 Hotel.



Based on this case study, one can see how new release video rental packages can be similarly tested, how price elasticity can be shown, and how market simulation will give Rogers Video an understanding of the market impact of changing it package parameters. From a data collection and analytical perspective, an Internet based DCM survey is a very powerful research approach.

TERASEN *GREEN GAS* STUDY: Final

INTRODUCTION

DISPLAY1

We are conducting a research study among British Columbia residents about their opinions on environmental issues. Please be assured that this is for research purposes only. It will take approximately 15 minutes of your time.

We would like the person in your household who is fully or jointly responsible for decisions about utility services to complete this survey.

QS1: M, QT

Are you a customer of the following utility companies? (*select all that apply*)

AL

Terasen Gas
BC Hydro
TELUS
None

QS2: S, QT

Do you or does any member of your household work for an energy utility, a gas marketer, or a public media, advertising, public relations or market research company?

AL

Yes
No

INSTRUCTION:
IF QS2 IS (NO) CONTINUE, ELSE TERMINATE

MARKET DRIVERS

QM1: M, QT

How concerned are you about…?

AL

10 – Very Concerned
9
8
7
6
5
4
3
2
1 – Not At All Concerned
Decline

MT — RANDOMIZE

The current state of the environment
The future state of the environment
The effects of global warming /climate change
Greenhouse gas emissions
The loss of oxygen producing forests
The level of government or industry leadership on environmental issues
Access to alternative energy solutions

ENERGY USE / GREEN PRODUCTS IN THE HOME			
QG1: S, QT	Have you taken steps to save energy in your home?		
AL	Yes No Don't know Decline		
	INSTRUCTIONS: IF QG1 IS (YES) CONTINUE IF QG1 IS (NO) GO TO QG3, ELSE GO TO NEXT SECTION		
QG2: M, QT	What steps have you taken to save energy in your home? (*select all that apply*)		
AL	Reduced water use (e.g. low flow showerheads) Energy efficient lighting Installed timers for lighting Installed a programmable thermostat Weather stripping / caulking Insulating windows / doors / spaces Re-using / reducing / recycling materials Replaced existing furnace with a high-efficiency furnace Alternative energy sources (e.g. heat pumps, solar panels) Other (Specify)	RANDOMIZE	
QG3: OPEN, QT	Why have you not taken steps to save energy in the home?		
AL	RECORD ANSWER Decline		

COMMITMENT

QCM1: M, QT

We know that different people have different lifestyles. For the following three types of lifestyles, what is your general **impression** of each one?

Please choose a number from 1 to 10, where '10' means you feel extremely positive and '1' means you feel extremely negative about that type of lifestyle.
(*select one for each*)

AL

10 – Extremely positive
9
8
7
6
5
4
3
2
1 – Extremely negative

MT

A lifestyle in which you consider the environmental impact of almost everything you do.

A lifestyle in which you consider the environment impact when it is reasonable or practical to do so.

A lifestyle where you do not consider the environmental impact of anything you do.

QCM2: S, QT

Now thinking about your own day-to-day lifestyle, which of the following best describes your current lifestyle. *(select one only)*

AL

A lifestyle in which you consider the environmental impact in almost everything you do.

A lifestyle in which you consider the environment impact when it is reasonable or practical to do so.

A lifestyle where you do not consider the environmental impact in anything you do.

QCM3: S, QT

Some things are extremely important and are worth thinking about, while others don't require much thought at all. Thinking about the different lifestyles that we have been discussing, how important is this decision in your life? (*select one only)*

AL

Extremely Important
Very Important
Moderately Important
Slightly Important
Not At All Important

QCM4: S, QT

Thinking now about your current lifestyle, to what extent can you think of reasons to continue with this lifestyle? (*select one only)*

AL

There are many good reasons to continue with your current lifestyle in relation to environmental choices and no reason to change.

There are many good reasons to continue with your current lifestyle in relation to environmental choices, but also many good reasons to change.

There are few good reasons to continue with your current lifestyle in relation to environmental choices and many reasons to change.

TERASEN GAS

QT1: M, QT

Terasen Gas is the primary natural gas provider in British Columbia. From your direct experience with the company, and from what you have heard, seen or read, on a scale from 1 to 10, where '10' means you feel Terasen is excellent and '1' means you feel Terasen is poor, how would you rate Terasen Gas in terms of being a company that cares about…?

PRE-MEASURE

AL

10 – Excellent
9
8
7
6
5
4
3
2
1 – Poor
Not relevant to me
Decline

MT

Its employees
Its role in the community
The environment
Making a profit
Re-investing in new environmentally-friendly technologies

RANDOMIZE

DISPLAY2

Terasen Gas is investing in a number of projects to collect methane gas produced from landfills, waste water treatment plants, animal manure and organic waste with the intention of delivering pipeline-quality gas to consumers.

By capturing, cleaning and delivering methane to the market that would otherwise be released to atmosphere; significant greenhouse gas reductions are achieved. We refer to this renewable gas as biogas.

Terasen hopes that by offering a biogas program, where customers can sign up for a portion of their energy use to be supplied from biogas, biogas can become a viable, renewable energy source for our region.

QT2: S, QT

Do you think Terasen Gas should be investing in biogas projects?

AL

10 – Definitely
9
8
7
6
5
4
3
2
1 – Definitely not
Decline

QT3: S, QT

Do you think Terasen Gas should invest in offering a biogas program to its residential customers?

AL

10 – Definitely
9
8
7
6
5

4
3
2
1 – Definitely not
Decline

QT4: S, QT

All things being equal, if Terasen Gas offered a biogas program, how likely would you be to sign up?

AL

10 – Very Likely
9
8
7
6
5
4
3
2
1 – Not Very Likely
Decline

INSTRUCTION:
IF QT4 IS (7-10) CONTINUE ELSE GO TO QP1A

QT5: M, QT

What, if any, would be your motivation for signing up for such a program? (*select all that apply*)

AL

RANDOMIZE

Promoting new technologies
Providing for future generations
Preserving nature
Human health
Doing the right thing
Status in your peer group
Being on the cutting edge
Supporting local farmers by providing income for their waste streams
Supporting local developments
Other (Specify)
Don't know

QT6: S, QT

And what would be your *most* important motivation for signing up for such a program? (*select one only*)

AL

RANDOMIZE

Promoting new technologies
Providing for future generations
Preserving nature
Human health
Doing the right thing
Status in your peer group
Being on the cutting edge
Supporting local farmers by providing income for their waste stream
Supporting local developments
Other (Specify)
Don't know

PRICE FOR BIOGAS

QP1: S, QT

The costs for a biogas program can be offered to consumers in one of two ways. Which way would you prefer to see Terasen offer this program, if it were to do so? *(select one only)*

AL

Terasen offers a biogas program for its customers to sign up for. Those who sign up would pay a premium for biogas.

The increase in cost for biogas supply would be borne by all Terasen Gas customers.

Don't know

INSTRUCTIONS:

SPLIT SAMPLE IN THIRD, INTO SAMPLE A, SAMPLE B AND SAMPLE C

IF SAMPLE A, ASK QP1A

IF SAMPLE B, GO TO QP2A

IF SAMPLE C, GO TO QP3A

INSTRUCTION:
IF QT3 IS (4-10) CONTINUE, ELSE GO TO QC1

QP1A: S, QT

If the cost of biogas is borne by all customers and you had to pay 3% more than the current commodity price of natural gas—which is about $1.80 more than the current monthly charge—would you or would you not support such a biogas program?

AL

Yes, would support program

No, would not support program

Don't know

INSTRUCTIONS:

IF QP1A IS (NO) OR (DON'T KNOW) CONTINUE, ELSE GO TO QC1

QP1B: S, QT

If the cost of biogas is borne by all customers and you had to pay 2% more than the current commodity price of natural gas—which is about $1.20 more than the current monthly charge—would you or would you not support such a biogas program?

AL

Yes, would support program

No, would not support program

Don't know

INSTRUCTIONS:

IF SAMPLE B CONTINUE, ELSE GO TO QC1

QP2A: S, QT

If the cost of biogas is borne by all customers and you had to pay 2% more than the current commodity price of natural gas—which is about $1.20 more than the current monthly charge—would you or would you not support such a biogas program?

AL

Yes, would support program

No, would not support program

Don't know

INSTRUCTIONS:

IF QP2A (NO) OR (DK) CONTINUE, ELSE GO TO QC1

QP2B: S, QT

If the cost of biogas is borne by all customers and you had to pay 1% more than the current commodity price of natural gas—which is about $0.60 more than the current monthly charge—would you or would you not support such a biogas program?

AL

Yes, would support program

No, would not support program

Don't know

INSTRUCTIONS:
IF SAMPLE C CONTINUE, ELSE GO TO QC1

QP3A: S, QT

If the cost of biogas is borne by all customers and you had to pay 1% more than the current commodity price of natural gas—which is about $0.60 more than the current monthly charge—would you or would you not support such a biogas program?

AL

Yes, would support program
No, would not support program
Don't know

INSTRUCTIONS:
IF QP3A (NO) OR (DK) CONTINUE, ELSE GO TO QC1

QP3B: S, QT

If the cost of biogas is borne by all customers and you had to pay 0.5% more than the current commodity price of natural gas—which is about $0.30 more than the current monthly charge–would you or would you not support such a biogas program?

AL

Yes, would support program
No, would not support program
Don't know

CARBON OFFSETS

QC1: S, QT

Have you heard of the term '**carbon offset'**?

AL

Yes
No
Not Sure

DISPLAY3

A **carbon offset** is what a buyer (you) receives in exchange for supporting a project that reduces greenhouse gases in the environment.

The buyer benefits because their purchase of a carbon offset balances out greenhouse gases released by the buyer's activities, such as home heating and cooling, driving a car or manufacturing.

The organization selling the **carbon offset** benefits because it makes offset projects more economically viable over time.

Offset projects range from planting trees—which absorb carbon dioxide from the atmosphere—to sophisticated renewable energy such as landfill methane capture and clean-up and high-efficiency equipment projects.

QC2: S, QT

Knowing this information, how likely would you be to purchase a **carbon offset** for your personal natural gas use in order to reduce your individual environmental footprint? *(select one only)*

AL

Already purchasing one
10 - Extremely likely
9
8
7
6
5
4
3
2
1 - Not at all likely
Need more information

ASK IF QC2 = 8/9/10, ELSE SKIP TO QC4

QC3: M, QT

Carbon offsets are sold through a number of sources. Would you prefer to purchase an offset through… *(select all that apply)*

AL

Your local utility provider
A 3rd party provider that supports projects in BC
A 3rd party provider that supports projects outside BC
Need more information / Don't know

DISPLAY4

There are potentially two types of pricing programs utilities could offer in relation to reducing residential environmental footprints – offset programs or renewable energy programs.

Offset programs – customers are offered the option to offset their home natural gas use by purchasing carbon offsets through the utility.

Most utility companies selling carbon offsets have criteria around which offsets will be purchased, e.g., their own renewable energy projects and / or third party biogas, wind projects or solar projects within their service territory.

Renewable energy programs – customers pay a premium for a portion of their natural gas to be supplied only from utility invested renewable energy projects such as biogas.

QC4: S, QT	Which of these two programs would you be more inclined to see Terasen Gas introduce, if it were to do so? *(select one only)*	
AL	Offset program Renewable energy program Neither Don't know	
	ASK ALL	
QC5: M, QT	What types of offset projects would you want to see Terasen Gas invest in outside of its own renewable energy projects? *(select all that apply)*	RANDOMIZE
AL	<u>Solar Power</u> - Generate energy from sunlight. <u>Geothermal Power</u> – energy extracted from the ground for heating. <u>Wind Power</u> - Use wind to create electricity. <u>Fuel Efficiency</u> - Burn a particular fuel more efficiently. <u>Fuel Substitution</u> - Switch to a fuel that emits less carbon such as diesel trucks to natural gas trucks. <u>Efficient Lighting</u> - Replace light bulbs with fluorescent lamps. <u>Heat-Electricity Cogeneration</u> - Create electricity and heat together. Energy from <u>Biomass</u> - Burn wood waste to generate electricity. <u>Forestation</u> - Plant trees which absorb carbon dioxide. <u>Environmental Buildings</u> - Make buildings more energy efficient. <u>3rd Party Biogas Projects</u> – within BC <u>3rd Party Biogas Projects</u> – outside BC <u>Public Transportation</u> - Subsidize or encourage the use of public transport. No preference None of the Above	

NATURAL GAS CHOICES

ASK QN1 IF QT2 = 4/5/6/7/8/9/10, ELSE SKIP TO QN3

ONLY ASKED IF INTERESTED IN BIOGAS PROGRAM

DISPLAY5

In the following section, you will be presented with several screens showing options for energy initiatives. Regardless of whether you would enrol in such a program, imagine your preference amongst the following choices.

Although some of the options will look similar from screen to screen, please pay attention to the details, as each screen is unique.

Please note the following definitions.

Renewable Energy Program:

The price premium paid would result in a portion of the customer's natural gas use being supplied from biogas and would contribute to making biogas become a more viable, renewable energy source for the region.

Carbon Offset Program:

The price premium paid by the customer would go towards purchasing offsets from utility invested biogas projects, as well as from other carbon offset projects and would contribute to offsetting greenhouse gases from a customer's natural gas use.

INSTRUCTIONS:

EACH SCREEN WILL INCLUDE TWO DIFFERENT CHOICES WITH TEXT TO DESCRIBE THE FEATURES IN EACH CHOICE SET. RESPONDENTS WILL SELECT THE OPTION THAT APPEALS TO THEM OR NEITHER OF THE CHOICES.

QN1: M, QT

If you were asked to support one of the following two choices from Terasen Gas, which option would you be the most likely to choose?

PAIR ALL COMBINATIONS OF LEVELS. ONE SCREEN PER PAIRING.

RANDOMIZE ORDER OF PAIRINGS

LEVELS

Energy initiative:

Renewable Energy Program

Carbon Offset Program

Percent Reduction In Your Green House Gas Emissions:

10 %

20%

30 %

50%

80%

100%

Effect On Monthly Gas Bill:

The current commodity price + 10% (about extra $6/month)

The current commodity price + 20% (about extra $12/month)

The current commodity price + 30% (about extra $18/month)

QN3: S, QT

Assuming Terasen Gas could develop and offer a renewable biogas program like the one we've been asking you about, how would you then rate Terasen Gas in terms of being a company that cares about…?

POST-MEASURE

AL

10 – Excellent

9

8

7

6

5

4

3
2
1 – Poor
Not relevant to me
Decline

MT
Its employees
Its role in the community
The environment
Making a profit
Re-investing in new environmentally-friendly technologies

RANDOMIZE

DEMOGRAPHICS

QD1: S, QT

Do you receive your gas bill directly from Terasen Gas or do you pay for your gas indirectly (e.g., through your rent payment, strata fees, etc)? (*select one only)*

AL

Receive bill directly from Terasen Gas
Pay gas bill indirectly
Does not use gas
Don’t know

QD2: M, QT

Which of the following natural gas appliances, if any, do you have in your home? (*select one for each*)

AL

Yes
No
Don’t know

MT

Natural gas furnace
Natural gas hot water heater that heats your tap water
Natural gas boiler for home heating
Natural gas range, cook top, or oven
Natural gas fireplace
Natural gas clothes dryer
Natural gas barbecue that uses the gas service from your home
Other natural gas appliances (SPECIFY)

D3: S, QT

What is the <u>main</u> space heating fuel type in your home? (*select one only)*

AL

Natural gas
Electricity
Piped propane
Bottled propane
Oil
Wood
OTHER
Don’t know / Not sure

D5: S, QT

Are you a homeowner or renter? (*select one only)*

AL

Homeowner
Renter
Decline

D6: S, QT

What type of dwelling do you live in? (*select one only)*

AL

Single-Detached house
Apartment Building / Condo
Row House / Townhouse / Condo Development
Duplex / Triplex
Suite contained within a house
Mobile or Manufactured home
Don’t know / Decline

D7: S, QT

In what area of BC do you live?

AL

Lower Mainland
Whistler
Interior
Vancouver Island
Sunshine Coast
Decline

QUESTIONS THAT WILL NOT BE ASKED, BUT COLLECTED THRU OUR PANEL STATS

PANEL: S,

QT Into which of the following age categories do you fall? (*select one only)*

AL
18 to 24 years
25 to 34 years
35 to 44 years
45 to 54 years
55 to 64 years
65 years or more
Decline

PANEL: S,

QT Including yourself, how many people live in your household?

AL
One
Two
Three
Four
Five
Six
Seven or more
Decline

PANEL: S,

QT Are there any children 18 years of age or under in the household? (*select one only)*

AL
Yes
No
Decline

PANEL: S,

QT What is the highest level of education that you have attained? (*select one only)*

AL
Public or elementary school
Secondary or high school
Technical or Cegep college
Community college
University
Post Graduate
Other

PANEL: S,

QT Which of the following best describes your household's 2008 total income before taxes? (*select one only)*

AL
Less than $15,000
$15,000 to less than $25,000
$25,000 to less than $35,000
$35,000 to less than $45,000
$45,000 to less than $60,000
$60,000 to less than $80,000
$80,000 to less than $100,000
$100,000 or more
Don't know / Decline

PANEL: S,

QT Are you…*[NOT ASKED – WILL GET INFO FROM PANEL]*

AL
Male
Female

DISPLAY	Thank you very much for participating in this survey. All information provided by you will be held in strictest confidence and will only be used for research purposes.

TERASEN *GREEN GAS COMMERCIAL* STUDY: TELEPHONE SCREENER Final

INTRODUCTION

DISPLAY1

Hello, my name is ___________ from TNS Canadian Facts. We are conducting a research study among British Columbia business leaders and organization decision-makers about their opinions on environmental issues. Please be assured that this is for research purposes only. We need just three minutes of your time, but first we need to ask:

QS1: S, QT

Is the company you represent an energy utility, a gas marketer, or a public media, advertising, public relations or market research company?

AL

Yes
No

INSTRUCTION:
IF QS1 IS (NO) CONTINUE, ELSE TERMINATE

We would like to talk to the person in your organization who is a chief or joint decision-maker concerning administrative or energy matters.

INTERVIEWER NOTE: SCREEN UNTIL YOU FIND THE APPROPRIATE INDIVIDUAL

QS2: M, QT

On a scale of 1 to 10 with ‘1’ being ‘not at all concerned’ and ‘10’ being ‘very concerned’, how concerned are you about the following environmental issues and their effect on your company…?

AL

10 – Very Concerned
9
8
7
6
5
4
3
2
1 – Not At All Concerned
Decline

MT

RANDOMIZE

The current state of the environment
The future state of the environment
The effects of global warming / climate change
Greenhouse gas emissions
Greenhouse gas regulations
The loss of oxygen producing forests
The level of government or industry leadership on environmental issues
Access to alternative energy solutions

QS3: S,

QT	Terasen Gas is interested in your valued opinion about how new sources of alternative energy could influence business attitudes and decisions. Representatives of businesses and organizations who complete the survey can choose to enter a prize draw for $500. The winner can also choose to donate this sum to a charity of their choice. Would you be willing to participate in a 20-minute online survey that goes into these topics more broadly?
AL	YES – CONTINUE NO – THANK AND TERMINATE DON'T KNOW – THANK AND TERMINATE
QS4: S, QT	Could we please have your email address? It will be used exclusively for the mentioned research project and will not be distributed or used for any other reason. Your survey answers will be held in strictest confidence and not be individually identified, but will be aggregated with all other returns.
AL	RECORD E-MAIL ADDRESS: ______________________ I do not want to disclose my e-mail address RECORD FIRST NAME ONLY (Optional): ______________________ I do not want to disclose my name INSTRUCTION: IF E-MAIL ADDRESS GIVEN, CONTINUE ELSE GO TO CLOSING.
DISPLAY2	Thank you. Within the next couple of days, we will be sending you an e-mail with a link to the survey and a unique id and password to enter the survey.

TERASEN *GREEN GAS COMMERCIAL* STUDY: Final

INTRODUCTION

DISPLAY1

We are conducting a research study with British Columbia organizations about their opinions on environmental issues. Please be assured that this is for research purposes only. It will take approximately 20 minutes of your time.

Thank you for agreeing to be a part of this important study.

ENERGY USE / GREEN PRODUCTS IN THE ORGANIZATION

QG1: S, QT

Has your organization taken steps to save energy at its location(s)?

AL

Yes
No
Don't know
Decline

INSTRUCTIONS:
IF QG1 IS (YES) CONTINUE
IF QG1 IS (NO) GO TO QG3, ELSE GO TO NEXT SECTION

QG2: M, QT

What steps have been taken to save energy in your organization? (*select all that apply*)

AL — RANDOMIZE

Reduced water use (e.g., aerators, water-conserving faucets)
Energy efficient lighting
Installed timers for lighting
Installed a programmable thermostat
Weather stripping / caulking
Insulating windows / doors / spaces
Replaced windows / doors with energy efficient windows / doors
Re-using / reducing / recycling materials
Replaced existing space heating equipment with high-efficiency upgrades
Installed a high-efficiency water heater
Alternative energy sources (e.g., heat pumps, solar panels)
Conducted energy saving awareness program with employees
Other (Specify)

QG3: OPEN, QT

Why has your organization not taken steps to save energy?

AL

RECORD ANSWER
Decline

COMMITMENT

QCM1: M, QT

We know that organizations adopt different practices. For the following three types of business practices, what is your general **impression** of each one?

Please choose a number from 1 to 10, where '10' means you feel extremely positive and '1' means you feel extremely negative about that type of practice.

(*select one for each*)

AL

10 – Extremely positive
9
8
7
6
5
4
3
2
1 – Extremely negative

MT

A business practice in which the organization considers the environmental impact of almost everything it does.

A business practice in which the organization considers the environmental impact when it is reasonable or practical to do so.

A business practice where the organization does not consider the environmental impact of anything it does.

QCM2: S, QT

Now thinking about your organization's business practices, which of the following best describe its current philosophy. *(select one only)*

AL

Your organization considers the environmental impact in almost everything it does.

Your organization considers the environmental impact when it is reasonable or practical to do so.

Your organization does not consider the environmental impact in anything it does.

QCM3: S, QT

Some things are extremely important and are worth thinking about, while others don't require much thought at all. Thinking about the different business practices that we have been discussing, how important are they for your organization? (*select one only)*

AL

Extremely Important
Very Important
Moderately Important
Slightly Important
Not At All Important

QCM4: S, QT

Thinking now about your current business practices, to what extent can you think of reasons to continue with this practice? (*select one only)*

AL

There are many good reasons to continue with your current business practices in relation to environmental choices and no reason to change.

There are many good reasons to continue with your current business practices in relation to environmental choices, but also many good reasons to change.

There are few good reasons to continue with your current business practices in relation to environmental choices and many reasons to change.

TERASEN GAS

QT1: M, QT

Terasen Gas is the primary natural gas provider in British Columbia. From your organization's direct experience with Terasen, and from what you have heard, seen or read, on a scale from 1 to 10, where '10' means you feel Terasen is excellent and '1' means you feel Terasen is poor, how would you rate Terasen Gas in terms of being a company that cares about…? (*select one for each*)

PRE-MEASURE

AL

10 – Excellent
9
8
7
6
5
4
3
2
1 – Poor
Not relevant to me
Decline

MT

Its employees
Its role in the community
The environment
Making a profit
Re-investing in new environmentally-friendly technologies

RANDOMIZE

DISPLAY2

Terasen Gas is investing in a number of projects to collect methane gas produced from landfills, waste water treatment plants, animal manure and organic waste with the intention of delivering pipeline-quality gas to consumers.

By capturing, cleaning and delivering methane to the market that would otherwise be released to atmosphere, significant greenhouse gas reductions are achieved. We refer to this renewable gas as biogas.

Terasen hopes that by offering a biogas program, where customers can sign up for a portion of their energy use to be supplied from biogas, biogas can become a viable, renewable energy source for our region.

QT2: S, QT

Does your organization support Terasen Gas investing in biogas projects?
(select one only)

AL

10 – Definitely
9
8
7
6
5
4
3
2
1 – Definitely not
Decline

QT3: S,

QT	Do you think Terasen Gas should invest in offering a biogas program to its commercial customers? *(select one only)*	
AL	10 – Definitely 9 8 7 6 5 4 3 2 1 – Definitely not Decline	
QT4: S, QT	All things being equal, if Terasen Gas offered a biogas program, how likely would your organization be to sign up? *(select one only)*	
AL	10 – Very Likely 9 8 7 6 5 4 3 2 1 – Not Very Likely Decline	
	INSTRUCTION: IF QT4 IS (7-10) CONTINUE ELSE GO TO QP1A	
QT5: M, QT	What, if any, would be the motivation for your organization to sign up for such a program? (*select all that apply*)	
AL	Promoting new technologies Providing for future generations Preserving nature Human health Doing the right thing Status in your peer group Being on the cutting edge Supporting local farmers by providing income for their waste streams Supporting local developments Meeting government greenhouse gas regulations Meeting corporate environmental initiatives Corporate image Other (Specify) Don't know	RANDOMIZE
QT6: S, QT	And what would be your organization's **most** important motivation for signing up for such a program? (*select one only*)	
AL	Promoting new technologies Providing for future generations Preserving nature Human health	RANDOMIZE

Doing the right thing

Status in your peer group

Being on the cutting edge

Supporting local farmers by providing income for their waste stream

Supporting local developments

Meeting government greenhouse gas regulations

Meeting corporate environmental initiatives

Corporate image

Other (Specify)

Don’t know

PRICE FOR BIOGAS

QP1: S, QT

The costs for a biogas program can be offered to consumers in one of two ways. Which way would you prefer to see Terasen offer this program, if it were to do so? *(select one only)*

AL

Terasen Gas offers a biogas program that its customers can sign up for. Those who sign up would pay a premium for biogas.

The increase in cost for biogas supply would be borne by all Terasen Gas customers.

Don't know

INSTRUCTIONS:

SPLIT SAMPLE IN THIRD, INTO SAMPLE A, SAMPLE B AND SAMPLE C

IF SAMPLE A, ASK QP1A

IF SAMPLE B, GO TO QP2A

IF SAMPLE C, GO TO QP3A

INSTRUCTIONS:
IF QT3 IS (4-10) CONTINUE, ELSE GO TO QC1

QP1A: S, QT

If the cost of biogas is borne by all customers and your organization had to pay 3% more than the current commodity price of natural gas—which is about $0.20 more per Gigajoule (GJ)—would your organization or would your organization not support such a biogas program?

AL

Yes, it would support program

No, it would not support program

Don't know

INSTRUCTIONS:

IF QP1A IS (NO) OR (DON'T KNOW) CONTINUE, ELSE GO TO QC1

QP1B: S, QT

If the cost of biogas is borne by all customers and your organization had to pay 2% more than the current commodity price of natural gas—which is about $0.13 more per GJ—would your organization or would your organization not support such a biogas program?

AL

Yes, it would support program

No, it would not support program

Don't know

INSTRUCTIONS:

IF SAMPLE B CONTINUE, ELSE GO TO QC1

QP2A: S, QT

If the cost of biogas is borne by all customers and your organization had to pay 2% more than the current commodity price of natural gas—which is about $0.13 more per Gigajoule (GJ)—would your organization or would your organization not support such a biogas program?

AL

Yes, it would support program

No, it would not support program

Don't know

INSTRUCTIONS:

IF QP2A (NO) OR (DK) CONTINUE, ELSE GO TO QC1

QP2B: S,

QT If the cost of biogas is borne by all customers and your organization had to pay 1% more than the current commodity price of natural gas—which is about $0.07 more per GJ—would your organization or would your organization not support such a biogas program?

AL
Yes, it would support program
No, it would not support program
Don’t know

INSTRUCTIONS:
IF SAMPLE C CONTINUE, ELSE GO TO QC1

QP3A: S, QT
If the cost of biogas is borne by all customers and your organization had to pay 1% more than the current commodity price of natural gas—which is about $0.07 more per Gigajoule (GJ)—would your organization or would your organization not support such a biogas program?

AL
Yes, it would support program
No, it would not support program
Don’t know

INSTRUCTIONS:
IF QP3A (NO) OR (DK) CONTINUE, ELSE GO TO QC1

QP3B: S, QT
If the cost of biogas is borne by all customers and your organization had to pay 0.5% more than the current commodity price of natural gas—which is about $0.04 more per GJ–would your organization or would your organization not support such a biogas program?

AL
Yes, it would support program
No, it would not support program
Don’t know

CARBON OFFSETS

QC1: S, QT

Have you heard of the term '**carbon offset'**?

AL

Yes
No
Not Sure

DISPLAY3

A **carbon offset** is what a buyer (your organization) receives in exchange for supporting a project that reduces greenhouse gases in the environment.

The buyer benefits because their purchase of a carbon offset balances out greenhouse gases released by the buyer's activities, such as heating and cooling, transportation activities or manufacturing.

The organization selling the **carbon offset** benefits because it makes offset projects more economically viable over time.

Offset projects range from planting trees—which absorb carbon dioxide from the atmosphere—to sophisticated renewable energy such as landfill methane capture and clean-up and high-efficiency equipment projects.

QC2: S, QT

Knowing this information, how likely would your organization be to purchase a **carbon offset** for its natural gas use in order to reduce your organization's environmental footprint? *(select one only)*

AL

Already purchasing one
10 - Extremely likely
9
8
7
6
5
4
3
2
1 - Not at all likely
Need more information

ASK IF QC2 = 8/9/10, ELSE SKIP TO QC4

QC3: M, QT

Carbon offsets are sold through a number of sources. Would your organization prefer to purchase an offset through…? *(select all that apply)*

AL

Your local utility provider
A 3rd party provider that supports projects in BC
A 3rd party provider that supports projects outside BC
Need more information / Don't know

DISPLAY4

There are potentially two types of pricing programs utilities could offer in relation to reducing customers' environmental footprints – offset programs or renewable energy programs.

Offset programs – customers are offered the option to offset their organization's natural gas use by purchasing carbon offsets through the utility.

Most utility companies selling carbon offsets have criteria around which offsets will be purchased, e.g., their own renewable energy projects and / or third party biogas, wind projects or solar projects within their service territory.

Renewable energy programs – customers pay a premium for a portion of their natural gas to be supplied only from utility invested renewable energy projects such as biogas.

QC4: S, QT

Which of these two programs would your organization be more inclined to see Terasen Gas introduce, if it were to do so? *(select one only)*

AL

Offset program
Renewable energy program
Neither
Don't know

INSTRUCTION:
ASK ALL

QC5: M, QT

What types of offset projects would your organization want to see Terasen Gas invest in outside of its own renewable energy projects? *(select all that apply)*

RANDOMIZE

AL

Solar Power - Generate energy from sunlight.
Geothermal Power – Extract energy from the ground for heating.
Wind Power - Use wind to create electricity.
Fuel Efficiency - Burn a particular fuel more efficiently.
Fuel Substitution - Switch to a fuel that emits less carbon such as diesel trucks to natural gas trucks.
Efficient Lighting - Replace light bulbs with fluorescent lamps.
Heat-Electricity Cogeneration - Create electricity and heat together.
Energy from Biomass - Burn wood waste to generate electricity.
Forestation - Plant trees which absorb carbon dioxide.
Environmental Buildings - Make buildings more energy efficient.
3rd Party Biogas Projects – within BC
3rd Party Biogas Projects – outside BC
Public Transportation - Subsidize or encourage the use of public transport.
No preference
None of the Above

NATURAL GAS CHOICES

ASK QN1 IF QT2 = 4/5/6/7/8/9/10, ELSE SKIP TO QN65

ONLY ASKED IF INTERESTED IN BIOGAS PROGRAM

DISPLAY5

In the following section, you will be presented with several screens showing options for energy initiatives. Regardless of whether your organization would enrol in such a program, imagine your preference amongst the following choices.

Although some of the options will look similar from screen to screen, please pay attention to the details, as each screen is unique.

Please note the following definitions.

Renewable Energy Program:

The price premium paid would result in a portion of the customer's natural gas use being supplied from biogas and would contribute to making biogas become a more viable, renewable energy source for the region.

Carbon Offset Program:

The price premium paid by the customer would go towards purchasing offsets from utility invested biogas projects, as well as from other carbon offset projects and would contribute to offsetting greenhouse gases from a customer's natural gas use.

INSTRUCTIONS:

EACH SCREEN WILL INCLUDE TWO DIFFERENT CHOICES WITH TEXT TO DESCRIBE THE FEATURES IN EACH CHOICE SET. RESPONDENTS WILL SELECT THE OPTION THAT APPEALS TO THEM OR NEITHER OF THE CHOICES.

QN1: M, QT

If your organization was asked to support one of the following two choices from Terasen Gas, which option would it be the most likely to choose?

PAIR ALL COMBINATIONS OF LEVELS. ONE SCREEN PER PAIRING.

RANDOMIZE ORDER OF PAIRINGS

LEVELS

Energy initiatives:

Renewable Energy Program

Carbon Offset Program

Percent Reduction In Your Green House Gas Emissions:

10 %

20%

30 %

50%

80%

100%

Effect On Monthly Gas Bill:

The current commodity price + 10% (about extra $0.65/GJ)

The current commodity price + 20% (about extra $1.30/GJ)

The current commodity price + 30% (about extra $1.95/GJ)

QN65: S, QT

Assuming Terasen Gas could develop and offer a renewable biogas program like the one we've been asking you about, how would you then rate Terasen Gas in terms of being a company that cares about…?
(select one for each)

POST-MEASURE

AL

10 – Excellent

9

8

7

6
5
4
3
2
1 – Poor
Not relevant to me
Decline

MT

Its employees
Its role in the community
The environment
Making a profit
Re-investing in new environmentally-friendly technologies

RANDOMIZE

DEMOGRAPHICS

QD1: S, QT

What sector is your organization in? (*select one only)*

AL

Retail
Government Organization
Office
Hospitality
Auto Repair / Gas Station
Construction
Agriculture
Food
Recreation
Institutional
Industrial
Wood & Forest
Commercial
Don't know / Decline

D2: S, QT

What is the main space heating fuel type in your organization? (*select one only)*

AL

Natural gas
Electricity
Piped propane
Bottled propane
Oil
Wood
OTHER
Don't know / Not sure

D3: S, QT

Are you a business owner or an employee? (*select one only)*

AL

Owner
Employee
Decline

D4: S, QT

In what area of BC is your office located?

AL

Lower Mainland
Whistler
Interior

	Vancouver Island Sunshine Coast Decline
QD5: S, QT	Does your organization have multiple locations?
AL	YES NO DON'T KNOW
QD6: S, QT	How many people does your organization employ in BC?
AL	1 -5 6-10 11 - 25 26 - 50 51 - 100 101 - 200 More than 200 Decline
QD7: S, QT	Which of the following best describes your organization's 2008 total revenue before taxes? (*select one only)*
AL	Less than $100,000 $100,000 to less than $500,000 $500,000 to less than $1,000,000 $1,000,000 to less than $5,000,000 $5,000000 to less than $10,000,000 $10,000,000 to less than $25,000,000 $25,000,000 or more Don't know / Decline
DISPLAY	Thank you very much for participating in this survey. All information provided by you will be held in strictest confidence and will only be used for research purposes.

Biogas Market Study

General Summary

Date: April 2010

Presented to • Présenté à
Terasen Gas

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www.tns-global.com

Contents

At TNS, we know that being successful in today's dynamic global environment requires more understanding, clearer direction and greater certainty than ever before. While accurate information is the foundation of our business, we focus our expertise, services and resources to give you greater insight into your customers' behavior and needs.

Our integrated, consultative approach reveals answers beyond the obvious, so you understand what is happening today – and what will happen tomorrow. That is what sets TNS apart.

Thank you for allowing us to explore your business needs. We hope you will continue to trust TNS to provide the insight you need to sharpen your competitive edge.

1.0 Foreword

1.1 Background

There are two major shifts impacting the energy sector: (1) the marketplace is becoming more diverse and competitive, and (2) environmental issues appear to be increasingly relevant to energy consumers. Being faced with these challenges, Terasen Gas (Terasen) has been repositioning itself as an integrated energy provider that can be both competitive and environmentally friendly (i.e., by minimizing the environmental impact of its activities).

As part of this new positioning, Terasen is exploring renewable energy initiatives that offer customers green energy choices based on biomethane fuels (biogas).

1.1.1 Study Objectives

TNS was commissioned to help Terasen better understand the potential residential and commercial markets for biogas, its market drivers, and sensitivities to different price points for a biogas program. Specifically, the research objectives for both the residential and commercial markets were to measure:

1. Market interest, the potential target market and market size for a renewable energy program (biogas);
2. Market interest and the potential target market for a carbon offset program;
3. Market drivers;
4. Price points and factors affecting price points; and,
5. Customer perceptions of different product offerings.

1.2 Methodological Overview

Data was gathered from both BC households and businesses using an online methodology. An online methodology was used to facilitate a discrete choice analysis – which cannot be done on the telephone or through a mail survey. A discrete choice exercise prompts respondents to choose between a series of program alternatives that trade-off different features. From their choices, it is possible to indirectly measure which elements weigh more heavily in respondents' energy decisions.

1.2.1 Residential Study

An online survey with 1,401 respondents was conducted between November 23 and December 4, 2009 among BC residents (18 years of age or older) using TNS Canadian Facts' online panel. TNS online panels are comprised of households who volunteer to complete surveys from time to time.

A quota sample was used to ensure feedback from three distinct types of residential households:

- Terasen Gas customers (those who receive a gas bill directly from Terasen);
- Indirect customers (gas users who are not billed directly i.e., gas costs are included in strata fees or rent); and,
- Non gas users (those who do not use gas).

Non gas users were included in this study to get a full picture of the BC residential energy market.

The reader is also urged to bear in mind that the sampling unit for this study is the household. All projections are made on the basis of residential Terasen customer households, and not individuals.

1.2.2 Commercial Study

A business sample of over 26,000 customers was provided directly by Terasen Gas to TNS for the commercial study as TNS does not currently have a commercial online panel. Commercial customers were contacted initially by telephone and those which choose to participate were then emailed a link to the online survey.

A total of 500 online surveys were completed by business customers of Terasen between December 14, 2009 and January 22, 2010. A very similar questionnaire was used for both residential and business respondents to allow for comparison between the two groups.

The table below summarizes the final interview counts for both residential and business studies.

Sample Composition

	Actual Interviews	Proportion of Total
	#	%
Residential Study		
Terasen Gas customers (receive gas bill directly from Terasen)	799	57%
Indirect customers (pay gas bill indirectly through rent or strata fees)	200	14%
Non-customers (does not use gas at home)	352	25%
Residents who don't know their energy source	50	4%
Total Residential Interviews	1,401	100%
Business Study		
Total number of interviews	500	100%

2.0 Executive Summary

Both the residential and commercial customer studies produced results that lead to several similar recommendations for Terasen. This is not all that surprising since commercial organizations are managed by individuals (or residents), whose philosophies, attitudes and personal experiences become part of an organization's corporate culture.

In this study, two different types of initiatives were presented to respondents: a biogas program and a carbon offset program. Both stakeholder groups confirmed, at different points in the study that they are more likely to sign up for a biogas program than a carbon offset program. If Terasen were to bring only one of these options to market, we would recommend a biogas program since it would yield a larger market share.

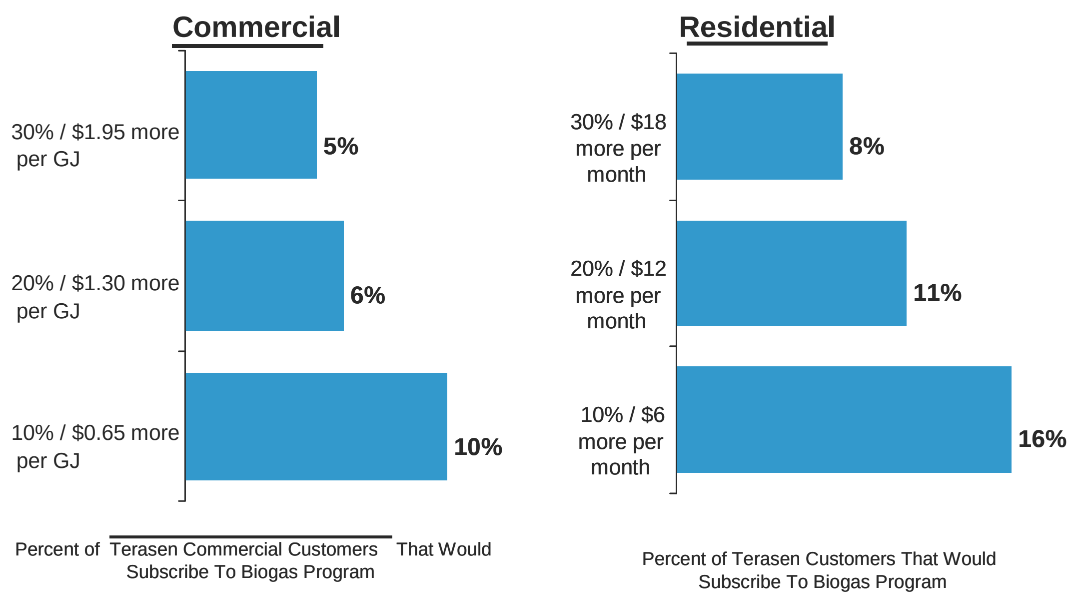
Specifically, if all factors today remained constant (e.g., energy prices remain unchanged), 56% of Terasen's residential customers and 47% of commercial customers would commit to a biogas program on the benefits of the fuel alone. However, this potential market declines if the cost of the program impacts their gas bill. Price is one of the main barriers to a biogas program for many residents and businesses – it prevents many residents and commercial customers from committing to the program. The survey explored pricing levels for a universal price increase as well as a program customers can sign up for at a premium. There was strong support for moderate price increases between 0.5% - 3% for a biogas program where costs were borne by all customers. For a user-pay program, 16% of residential customers and 10% of commercial customers indicated they would enrol in a biogas program at a 10% increase to their current commodity price. Market share projections at various pricing levels for a user-pay biogas program are detailed later in this summary.

Finally, residential customers are more enthusiastic about committing to a biogas program than commercial customers. There appears to be greater hesitation on the part of commercial customers. This fact, coupled with the larger residential market, makes residential households a potentially more lucrative segment to target (than commercial customers).

2.1 Market Projections

Using projections obtained through both the survey data and Terasen's customer data, it is possible to get an idea of what proportion of commercial customers and residential households might potentially subscribe to a biogas program at different price points. The chart below summarizes the results obtained from residential and commercial customers. It shows initial enrolment rates and drop-off levels at key price points for incremental price increases to the commodity rate for a user pay program as well as support for universal price increase levels for a biogas program where costs are borne by all customers.

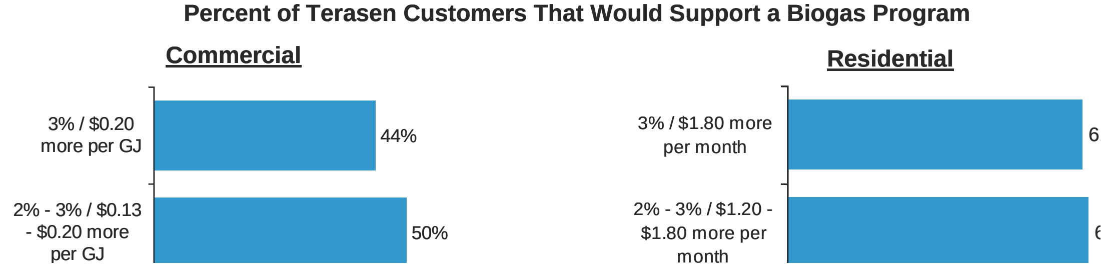
Market Size Projections For a User Pay Program



Above figures are based on share of preference (DCM analysis) with corresponding GHG reduction levels associated with each price point.

Universal Price Increase Support

Percent of Terasen Customers That Would Support a Biogas Program



Above figures are based on a direct line of questioning.

2.2 Pricing

The decision on the optimal price point to introduce a biogas program will depend on Terasen's goals. If it is…

- To maximize household and business involvement, introduce universal price increases borne by all customers;
- To maximize household and customer involvement with premium pricing, increase current prices by 10%;
- To balance Greenhouse Gas (GHG) reductions with premium pricing; increase current prices by 20%; and,
- To offer higher GHG reductions, higher price increases of 30% (or more) will be required.

2.3 Communications Campaign

Enrolment rates for a biogas program will also depend on the strengths of Terasen's communications and marketing. As illustrated in the trade-off analysis, any marketing campaign must demonstrate the environmental benefits of biogas and how it reduces greenhouse gas emissions. The level of greenhouse gas reductions associated with a program has a strong influence on which programs customers will support. This is particularly true for customers that indicate they wish to see a higher GHG reduction for programs with a higher premium.

With respect to the potential target segments for a biogas program, we recommend designing a communications strategy aimed at residential households first. On the residential side Terasen should target:

- Customers who have "green" tendencies;
- Higher educated and higher income households (they tend to be less price sensitive);
- Females (they tend to be more green); and,
- Those who have participated in past energy savings programs.

For commercial customers, a more universal communications strategy should be applied, which demonstrate environmental value for the price paid. Businesses want to see how much of their carbon footprint is being reduced, for each extra dollar that they spend. In this regard, Terasen might consider updating its current billing template to incorporate this additional information.

For Detailed Results – See General Summary

3.0 General Summary

3.1 Residential Findings

As noted previously, Terasen sought input on environmentally-friendly energy initiatives, namely a biogas program and a carbon offset program, from BC residents and commercial customers. This section summarizes results obtained from BC residents (n=1,401). The results gathered among commercial customers are summarized in the next section.

3.1.1 Opinions On Biogas

Approximately two-thirds of residents will support Terasen if the organization opts to invest in biogas projects and an equal number feel Terasen should offer a biogas program for customers. While roughly two-thirds of residents endorse a Terasen biogas program, 56% would sign up for a biogas program. Motivations for enrolment vary, with top reasons among potential enrollees being: providing for future generations; preserving nature, and doing the right thing.

Should Terasen Be Investing In Biogas

	Total
Base: Total respondents	(1,401)
Yes (8-10)	67%
Maybe (4-7)	27%
No (1-3)	2%
Decline	4%

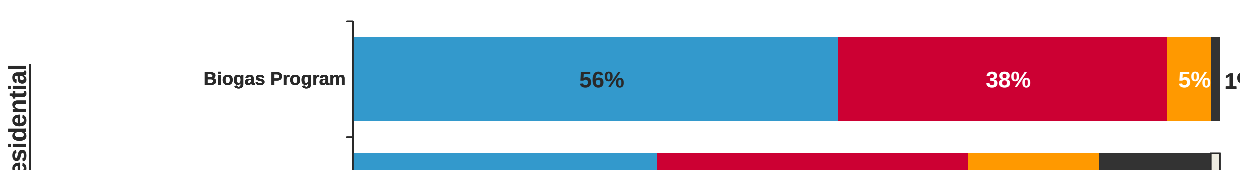
Should Terasen Offer A Biogas Program

	Total
Base: Total respondents	(1,401)
Yes (8-10)	65%
Maybe (4-7)	30%
No (1-3)	1%
Decline	4%

3.1.2. Opinions On Carbon Offsets

Residents were also asked about their support for carbon offsetting programs. While approximately half of residents are aware of carbon offsets, just three-in-ten (31%) indicated likelihood of purchasing them to offset their personal natural gas use. When asked to choose which program they would prefer to see Terasen introduce, residents chose a biogas program over carbon offsets by a three-to-one margin.

Likelihood To Sign Up For Terasen Offered Programs:



3.1.3 Price For Biogas

Residents who expressed an interest in signing up for a biogas program were asked directly whether they would prefer to have a Terasen biogas program funded through a universal price increase (borne by all consumers) or through price premiums for only those who enroll in the program. There was a stronger preference voiced for a universal price increase (47%), compared to a biogas program people can sign up for at a premium (26%), but a considerable number of respondents indicated they did not know which one they would prefer (27%).

As consumers will see the impact of a biogas program on their gas bill, it was also important to explore what size of increase residents might be comfortable with. All respondents were asked universal price increase questions directly in order to explore what level of price increase they would support (up to 3%). This information was supplemented with indirect questions through the discrete choice exercise to explore higher pricing increases (10% to 30% commodity price increase for a program customers can sign up for at a premium).

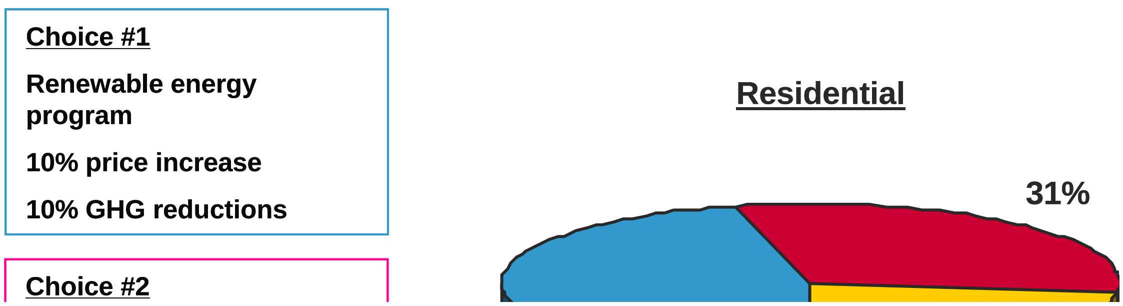
As expected, support for the biogas program decreases as the potential impact on the consumers' gas bill rises. Seventy-eight percent of residential customers indicated they would support a universal price increase of 0.5% to 1%. However, slightly fewer (62%) would still support a universal price increase of up to 3%, revealing there is a substantial proportion of the market willing to financially support biogas initiatives.

3.1.4 Preferred Program Options

The Discrete Choice Model (DCM)[1] included in the survey also indirectly measures which features weighed more heavily in residential energy choices. The discrete choice exercise explored the relationship between the price of renewable energy options (measuring steeper price increases of 10%-30%) and greenhouse gas reductions. These results confirm that price is an important consideration, but can be counteracted by the prospect of disproportionately higher greenhouse gas reductions (e.g., 20% price increase yielding a 30% GHG reduction is as popular as an option that sees a 10% cost increase and a 10% reduction).

In the following simulation, we compare three different biogas programs that respondents can choose from (a program with a 10% GHG reduction and 10% price premium; a program with a 20% GHG reduction and a 20% price increase; or a program with a 30% GHG reduction and 30% price increase). The program with a 10% GHG reduction and 10% price increase is preferred by 46% of residential customers who said they would sign up for a biogas program. The two choices with the higher price increases were preferred by a smaller proportion of residential customers.

[1] A Discrete Choice Model (DCM) asks respondents to choose between a series of program alternatives that trade-off on different features. From their choices, a DCM model is able to indirectly measure which elements weighed more heavily on a respondent’s selections. In this study, a model was built on three dimensions – (1) type of energy initiative, (2) percent reduction in GHG levels, and (3) effect on monthly gas bill. Thirty-six possible pairings of choice sets were built into the questionnaire, based on different permutations of the three dimensions. Each respondent was presented with a random set of 16 pairings and asked to select the scenario they preferred in each pairing.



3.1.5 Estimating Market Potential

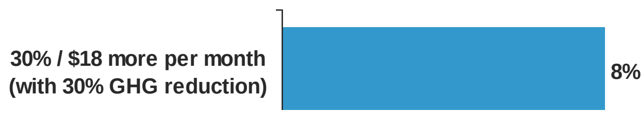
Using the survey data, it was possible to generate rough estimates of potential market share for a biogas program. The projected market estimates were calculated based solely on what respondents told us. Knowing this, we would caution that these figures should be considered best case estimates. The reason for caution is two-fold:

- People do not always do what they say – we often fall short of our intended goals; and,
- Respondents sometimes have the tendency to provide answers in a manner consistent with how they perceive we want them to answer – in this case, to sign up for a biogas program because it has positive impacts on our environment.

The market projections in this section of the report are based on Terasen customers who receive a gas bill directly from Terasen as these customers are accessible to Terasen and have the greatest control over whether or not their households would sign up for such program. We excluded all other residents from this analysis.

The reader is also urged to bear in mind that the sampling unit for this study is the household. All projections are made on the basis of residential Terasen customer households, and not individuals.

The chart on the following page uses the market projections to get an estimate of what proportion of residential households might potentially subscribe to a biogas program province-wide at different price points. Among Terasen residential customers, 56% indicated a willingness to sign up for a biogas program if there are no cost implications. As soon as the biogas initiative has cost implications on the residential gas bill, enrollment levels begin to drop off. It is estimated that 16% of those interested in signing up for a biogas program would support a user pay premium of 10% or $6 per month – if it results in a 10% reduction in GHG levels.



3.1.6 Profile Of Potential Biogas Market

Generally speaking, the demographic profile of residents voicing support for biogas initiatives does not differ greatly from that of residents who are not supportive. However, education and income appear to be two factors that differ between supporters from detractors. This information may help Terasen direct marketing efforts towards receptive customers.

3.2 Commercial Findings

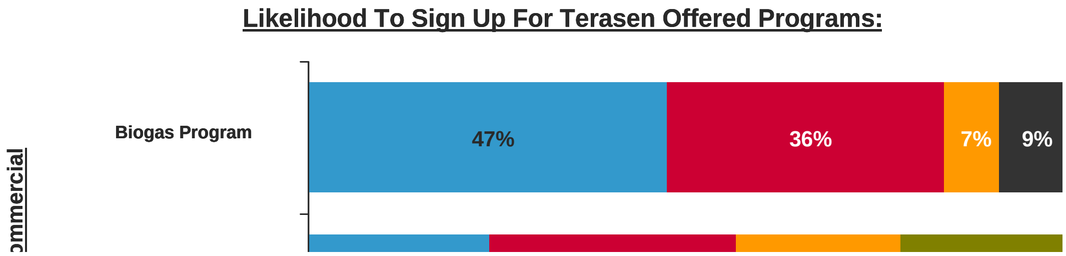
The following section highlights results gathered among Terasen's commercial customer base (n=500).

3.2.1 Opinions On Biogas

Similar to support levels found among BC residents, 67% of commercial customers will support Terasen if the organization opts to invest in biogas projects. Support for Terasen offering a biogas program is higher among commercial customers than among residents (71% support the initiative compared to 65% of residents). Similar to the pattern seen among residents, support for a biogas program is strong, but a smaller proportion (47%) indicates they would actually enroll in it. Motivations for enrolment among commercial customers vary, with primary reasons being: doing the right thing; providing for future generations, and preserving nature.

3.2.2 Opinions On Carbon Offsets

Commercial customers are more aware of about carbon offsets than residents (66% awareness versus 50% among residents). Despite higher awareness levels, just 24% indicated likelihood of purchasing them to offset their business' natural gas use. When asked which program they would prefer to see Terasen introduce, commercial customers chose a biogas program over carbon offsets by a three-to-one margin, mirroring the residential findings.

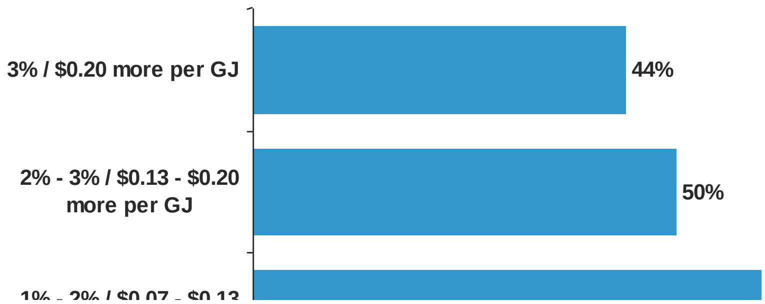


3.2.3 Price For Biogas

As with residents, commercial customers interested in a biogas program were asked directly whether they would prefer to have a Terasen biogas program funded through a universal price increase (borne by all consumers) or through price premiums only for those who enroll in the program. Unlike residents who were unable to provide a conclusive assessment of funding options, commercial customers came out strongly in support of a universal price increase (supported by 60% of commercial respondents). Nineteen percent supported a premium price increase and 21% said they did not know.

It was also important to explore what size of increase commercial customers would be comfortable with for a universal price increase versus a voluntary program. As with the residential surveys, this information was gathered through a *direct* question about support at different price points (up to a 3% commodity price increase for a universal price increase) and *indirectly* through the discrete choice exercise (for 10% to 30% commodity price increase for a program customers can sign up for).

Overall, commercial customers are much more apprehensive than residential customers when it comes to supporting a biogas program when there are cost implications. Half of commercial customers would support this concept if it meant their gas bill would increase by up to 3%.



3.2.4 Preferred Program Options

The Discrete Choice Model (DCM) included in the survey also indirectly measured which features weighed more heavily in commercial customers' energy choices. The discrete choice exercise explored the relationship between the price of renewable energy options and greenhouse gas reductions. Consistent with the residential findings, these results confirm that price is an important consideration, but can be counteracted by greenhouse gas reductions proportionally larger than price increases (e.g., 20% price increase yielding a 30% GHG reduction is as popular as an option that sees a 10% cost increase and a 10% reduction). Indeed, results show commercial customers are particularly concerned about reducing GHG levels. However, like with residential customers, commercial customers also prefer the option of a 10% GHG reduction and a 10% price increase, among the three options presented in the DCM simulation on the following page.

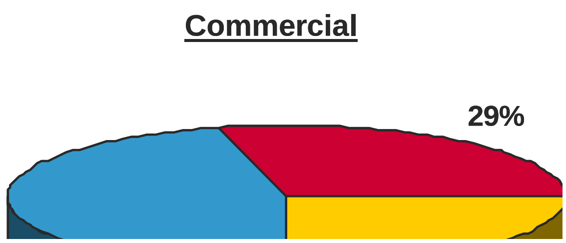
Choice #1

Renewable energy program

10% price increase

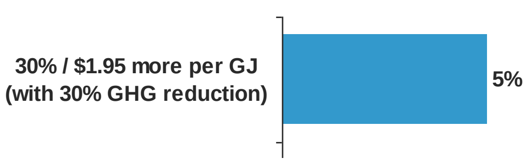
10% GHG reductions

Choice #2



3.2.5 Estimating Market Potential

The chart below uses market projections to develop an estimate of what proportion of businesses might potentially subscribe to a biogas program across the province. As noted earlier, 47% of commercial customers indicate willingness to sign up for a biogas program if there are no cost implications. As soon as the biogas initiative has cost implications on the gas bill, enrollment levels begin to drop off. It is estimated that 10% of those interested in signing up for a biogas program would support a user pay premium of 10% or $0.65 more per GJ – if it results in a 10% reduction in GHG levels.



3.2.6 Profile Of Potential Biogas Market

The commercial customers most likely to enroll in the biogas program include those who have participated in past energy saving programs, single location organizations (as opposed to those with multiple locations), and those who express concern for the environment.

Technical Appendix

Overview

A total of 1,401 online interviews were conducted between November 23 and December 4, 2009 with a sample of British Columbia residents. In addition to these residential interviews, 500 interviews were conducted with commercial customers of Terasen from December 14, 2009 to January 22, 2010. Results obtained from this survey provide valuable insights into understanding perceptions of Terasen and feature preferences for a renewable biogas program.

Sample Frame And Design

The samples used in this survey were drawn from two different sources. TNS' Canadian online adult panel was used to intercept BC residents. All BC communities were sampled. A quota cell design was used for this survey to ensure that a specific sampling level was achieved with respect to Terasen's own customers and non-customers. The number of completed interviews for each quota group are outlined below.

Sample Composition

	Actual Interviews	Proportion of Total
	#	%
Residential Study		
Terasen Gas customers (receive gas bill directly from Terasen)	799	57%
Indirect customers (pay gas bill indirectly through rent or strata fees)	200	14%
Non-customers (does not use gas at home)	352	25%
Residents who don't know their energy source	50	4%
Total Residential Interviews	1,401	100%
Business Study		
Total number of interviews	500	100%

Respondent Selection And Qualification

Respondents were selected differently for the two studies. On the residential side, respondents were randomly selected from TNS' online panel. This includes both gas users and non-users. On the commercial survey, respondents were restricted to Terasen customers and drawn randomly from Terasen's database. On both studies, respondents who work for a utility, gas marketer, the media, a research or advertising firm, were screened out of the study.

Questionnaire Development

The residential questionnaire was developed by TNS Canadian Facts in consultation with Terasen Gas. Prior to the start of interviewing, a pretest was conducted over the first weekend of field to ensure the workability of the questionnaire and to finalize question sequencing.

The commercial questionnaire is almost identical to the residential questionnaire with slight modifications.

Data Collection

Residential respondents were recruited from TNS' online panels and directed to the survey site to complete the survey.

Commercial respondents were recruited from Terasen's customer database. These respondents were first approached by phone. Once their participation was secured, they were asked for their email addresses, so that the survey link could be sent to them. The survey had to be conducted online because the DCM analysis contained in this research project requires an online interface with respondents.

Survey Margin Of Error

Please note that margins of error apply to randomly selected samples. Residential panel samples are self selected and therefore the following margin of error figures are presented as a guide for readers. The overall sampling error for 1,401 total residential interviews at the 95% confidence level is approximately ± 2.6%. For example, if 50% of all residents surveyed stated that they have heard of carbon offsets, then we can be sure, nine times out of ten, that if the entire population had been interviewed, the proportion would lie between 47.8% and 52.2%.

When a segment of the entire data is analyzed, the sampling error increases. For example, the overall sampling error for data based on 200 interviews at the 95% confidence level is approximately ± 7.0%. In this case, using the scenario where respondents surveyed state that they would purchase a carbon offset, then we can be sure, nine times out of ten, that this proportion would lie between 43.0% and 57.0%.

The commercial survey results are subject to margins of error. At the 95% confidence level, the margin of error for the 500 commercial customers' interviews is ± 4.4%.

A copy of the invitation and questionnaire used in this survey are appended to this report.

Appendix E

BUSINESS RULES

Program Business Rules

Business rules are critical for successfully establishing the structure of the new Green Gas program. They are also important because they are used to provide the means to manage the program on an ongoing basis, and to influence the behaviour of participants Terasen Gas developed Guiding Principles to assist with developing the program and its supporting business rules. The Green Gas Guiding Principles detailed in Section 6 provided the basis to shape the development of the proposed framework and business rules for a Residential and Commercial Green Gas offering. The principles were not evaluated against a formal weighting system, rather they were used as a reference to ensure the selection of an appropriate model was taking into consideration various aspects of the Company's business.

The following business rules form the basis on which the Green Gas program will be established and for offering a biomethane tariff. Terasen Gas believes it has developed a framework that is balanced, utilizing existing business rules where appropriate in order to provide a cost-effective and sustainable Green Gas offering. While the initial offering is proposed for residential customers, the business model is scalable and therefore, the below business rules may only need minimal changes when expanded to include commercial customers.

In this Appendix Terasen Gas describes:

a) Eligibility;
b) Enrolment;
c) Contract Length;
d) Mobility;
e) Customer Billing and Collections;
f) Disputes; and
g) Biomethane Supply Failure.

These business rules are discussed in further detail below

Eligibility

For Phase I of the Green Gas program, customers eligible include those in residential Rate Schedule 1, but exclude those customers who are currently enrolled with a Gas Marketer. Specifically this includes residential customers on the mainland of British Columbia, but excluding Fort Nelson, and Revelstoke. Customers currently enrolled with a Gas Marketer will not be eligible to enrol in the Green Gas program until their contract with their Gas Marketer expires. Phase 1 will also seek approval of wholesale

Biomethane Tariffs Rate 11B for on-system and an amendment to Rate 30 for off-system sales which will allow for bulk purchases of Biomethane supported through Terasen's current internal gas supply processes which will allow for the selling of excess supply while participation rates are ramped up or commitment for firm supply amounts which will help support further Green Gas program development.

Phase 2 of the program is foreseen to be launched around the first quarter of 2012 should sufficient supply be established or there is additional supply available from the initial offering. Phase 2 envisions an expansion of eligible customers to include those in commercial rates 2 and 3 as well as a possible expansion to other regions such as Vancouver Island, the Sunshine Coast, Powel River, and Whistler, subject to their potential transition to an unbundled service model so the offering could be supported through the same business model. A further expansion to commercial rate classes 4 to 7 in 2013 is also contemplated. Details of the Phased rollout are discussed in Section 6.

Enrolment

Terasen Gas proposes an open enrolment and exit process in order to mirror the management of the current Terasen Gas standard supply rate and to provide customers with the maximum flexibility to move back to the standard supply rate or to a Gas Marketer as they choose. The effective date of a new enrolment will be the first of the month. An exception to this process involves account finalizations which will be processed as they are removed from the system.

The program will be subject to an enrolment limit based on the volume of biomethane available. Processes will be established to monitor demand, supply, cap enrolment and manage a possible waitlist if necessary. For example, for the initial residential offering if there is 150,000 GJ / yr of biomethane supply and a 10% biomethane Tariff, based on average use rates of 95 GJ per year, Terasen Gas would impose an enrolment limit of approx 12,000 - 15,000 residential customers. The Company may choose to cap this limit somewhat lower during these initial proposed phases in order to confirm supplier reliability or allow for some storage of biomethane supply as backup to ensure the Company doesn't over commit the program.

Customers wishing to participate in the new Green Gas program may enrol by calling the Company's call centre or apply online through account online. Processes and cost estimates for new enrolments have been drafted at a high level as part of the system impact review as discussed in Section 10 and will need to be implemented prior to rollout of the program. A customer may withdraw from the program using the existing customer service channels of either phone, fax or email.

Contract Length

There will be no set term obligating a customer to remain for a minimum amount of time on a Green Gas offering. It is expected that customers enrolling in the program will remain on the biomethane rate they have selected until they decide to change to another rate or drop from the program entirely. Any customer electing to participate in the Customer Choice program will be automatically removed from the Green Gas program should they be enrolled in that program when a contract with a Gas Marketer takes effect. The Company does not anticipate a need to impose a penalty for program termination by a customer, customers dropping from the biomethane tariff to go to the Terasen Gas standard supply rate, or to a decision to participate in the Customer Choice program.

Mobility

When a Green Gas customer moves to a new premise, the customer will be asked if they wish the new premise to remain on the biomethane tariff, providing the premise qualifies (i.e. it is in an eligible region and rate class and not currently supplied by a Gas Marketer). If the new premise is not an eligible account then they will revert to the standard commodity supply rate, unless the customer has signed up with a Gas Marketer in which case the premise will stay with that marketer. This process is slightly different than the Customer Choice model where the contract automatically ports to the customer's new premise. As the customer will have not signed a contract for the Biomethane Tariff, this will be a manual process at least in the initial stages.

Customer Billing & Collections

Terasen Gas will continue to provide the billing and collections service for customers signed up on the biomethane tariff in same manner as for customers who remain on Terasen Gas' standard supply rate. No changes to this process are needed in order for the Green Gas program to operate.

Disputes

Terasen Gas will continue to provide complaint and dispute resolution for customers signed up on the biomethane tariff on the same basis as customers who remain on Terasen Gas' standard supply rate. No changes to this process are needed in order to support the Green Gas program.

Biomethane Supply Failure

In the case of biogas producer failure that results in an inability by the Company to deliver the necessary biomethane volumes to customers, Terasen Gas reserves the right to purchase carbon offsets on the customers' behalf using biomethane proceeds in order to meet the GHG reductions that the customer had agreed to as set out in the Green Gas product offering. It is Terasen's intent to only use the above-mentioned reserved right as a last resort if biomethane demand volumes cannot be delivered within the year in order to retain the integrity of the GHG reduction portion of the program. The purchase of carbon offsets shall not exceed the amount of biomethane proceeds collected from Green Gas customers and any cost difference will be adjusted in the Biomethane Variance Account, discussed in Section 10 of this Application.

Alternative Cost Recovery Models Considered

Terasen Gas considered four business models that could be used to implement the Green Gas Program. These four models were considered and explored in conjunction with the Company's Green Gas Guiding Principles and are discussed below.

Table E-2-1: Alternative Cost Recovery Models Considered

Model	Description	Pros	Cons
Universal Price Increase: 1. Terasen Gas Revenue Requirement Proposal- Midstream (Rate Schedule 1-7)	Stream all costs of Biomethane production through the midstream and charge costs to all customers that pay midstream rate.	No IT or system costs. No need to create individual rates to specific customers.	No individual sales offering to help customers conform to GHG reduction targets. Increased cost to all midstream customers because no offsetting sale at a premium.
User Pay Models: 2. Customer Choice (Essential Service Model or ESM)	Follow the ESM business rules and treat Biogas as part of the annual base load supply received from Gas Marketers and Terasen Gas Standard Rate offering.	Leverages existing IT and systems for customer enrolments. Leverage existing internal process.	Biomethane supply is not firm and cannot be replaced at source. Gas received at the three supply hubs in the ESM can be replaced. Biomethane production curve is not flat as is the gas received from Marketers and Terasen Gas Standard offering. Does not fit the Monthly Supply Requirement or annual base load model that defines ESM.

Model	Description	Pros	Cons
3. Transport (Rate Schedules 22, 23, 25, and 27)	Sell directly to only transport customers	Large volume market that have GHG reduction compliance targets	Transport customers as a primary target market would face several challenges at this point in time. Such as: Biomethane supply is a constraint that would restrict the amount of customers that could purchase this product. New business rules with the Transportation model would need to be developed for balancing gas and delivery failure. Biogas supply is not firm and cannot be replaced at source. Gas received at the three supply hubs in the ESM can be replaced. Biogas production curve is not flat as is the gas received from Marketers and Terasen Gas Standard offering. Program costs will need to be incurred As a secondary market, Terasen Gas can sell excess Biomethane to Gas Marketers for on-system transport customers as a (see Section 11) more cost effective sale channel without getting into customer balancing rules, business rule or ESM changes.

Model	Description	Pros	Cons
4. Hybrid Midstream Model – Recommended Green Gas Business Model	Midstream manages supply and volumes variances due to production curve of Biogas Create a deferral account to recover costs for Biogas supply directly from customers who elect in the program	Leverage existing IT and systems with some modifications Supply issues managed in Midstream No impact to the ESM Same model as RRA Midstream, but now have added cost recovery mechanism for most costs recovered from those who elect in the program	Program costs will need to be incurred

Each model is described below further below.

1. Universal Price Increase (Terasen Gas Revenue Requirement Proposal)

A Green Gas program with costs borne by all customers has several advantages. It would avoid billing system enhancements and program administrative costs and second, it would allow for faster development of Biogas projects without having to tie supply with specific demand forecasts or customer. There was also very strong support for a Green Gas program where the costs were borne by all customers in the Company's market research as discussed in Section 5. However, as proposed, no individual customer could account for the GHG reduction because no specific customer is buying or paying for the increased cost of this Biogas gas.

2. Customer Choice Model (ESM)

Terasen Gas considered developing a Green Gas program based on ESM, which serves as the platform to deliver Customer Choice to both residential and commercial customers. Its primary attraction was the potential to use established customer enrolment, and billing processes that would require little modification.

However, the production of Biomethane is not the same as the firm annual base load gas that is delivered into the Midstream resources at the three supply hubs as defined in the ESM. The difference resides in two facts. First, the Biomethane production curve is not flat. Secondly, the Biomethane production cannot be replaced if there is a production outage at the facility.

As a result of these fundamental drawbacks, this model was not pursued.

3. Transportation (Rate Schedules 22, 23, 25 & 27)

During the design of the business model, the Company eliminated the Transportation model (Business Model 3 in Table E-2-1) due to the following reasons:

1. Biomethane supply restricts the amount of customers that could be served in this model
2. Current business rules that exist would need to be changed to support the impact of a new supply source on the distribution network, and the impacts of this variable supply source on balancing rules and supply failures.
3. As a secondary market, Terasen Gas can sell excess Biomethane to Gas Marketers for on-system transport customers as a backstopping measure more cost effectively without getting into customer balancing, business rule or ESM changes.

As a result of these fundamental drawbacks, this model was not pursued.

4. Proposed Green Gas Business Model

As discussed in further detail in Section 6, the Company proposes to phase-in the implementation of the Green Gas program over a multi-year period to ensure that the Green Gas product offering is effectively positioned for customer participation and to match the supply that is available. Key program features include:

- The Company proposes creating a new Biomethane tariff to allow eligible customers to either remain on the standard commodity rate (e.g., Terasen Gas Standard Rate) or to select the Terasen Gas Biomethane Tariff. The Biomethane Tariff will be a specific blend of Biomethane and conventional natural gas (for this Application, Terasen Gas proposes a blend of 10% Biomethane and 90% conventional natural gas). The Green Gas sales model selected by Terasen Gas as the basis for implementing the Green Gas program was determined to be the most suitable because it is able to mirror Terasen Gas' current Standard Rate offering, leverage existing systems and infrastructure in order to minimize system impacts and the need to incur incremental costs, and does not impact the Essential Service Model. The price of the new tariff will be at a premium, compared with the standard commodity rate from Terasen Gas. The proposed sales model is designed to leave the Customer Choice program and its customers unaffected. The customer continues to have choice of commodity supplier between a Gas Marketer's fixed rate and the Terasen Gas variable rate. Customers electing to participate in the Customer Choice program may not be enrolled in the Green Gas program and any customer who is enrolled in the Green Gas program and who elects to participate in the Customer Choice program would be automatically removed from the Biomethane tariff. Gas Marketer rules and functionality that are part of the Customer Choice program will remain unchanged.

- By electing to remain with Terasen Gas as the commodity supplier, a customer may choose to remain either on the standard rate (e.g., Terasen Gas Standard Rate Schedule 1) or they may select the Biomethane option (Terasen Gas Rate Schedule 1B), which is understood to be a specific blend of Biomethane (10% Biogas; 90% conventional natural gas).
- The number of customers eligible to participate in the Customer Choice program will not be impacted and the Gas Marketer base load requirements will be calculated based on the same methodology that exists today. This methodology is defined as the Monthly Supply Requirement or MSR.
- Biomethane rates will typically be set on a forecasted 12 month period with the rate reset on a January 1 effective date (the initial offering anticipated effective October 1, 2010 will be based on a 15-month forecast period). The non-Biomethane commodity tariff rate will remain subject to quarterly rate adjustments, and the resulting blended commodity rate that customers will see on their bills could change up to four times a year as the standard commodity rate changes.
- The Biomethane residential tariff, a copy of which is included in Appendix F-3, will be an open tariff like the Terasen Gas Standard Rate Schedule 1 and allows for customers to elect to participate in and exit from the Green Gas program as they see fit. Customers currently enrolled with a Gas Marketer can only return to the Terasen Gas Standard offering, or enrol in the Biomethane tariff at the expiration of their Gas Marketer contract.[1]

The Company proposes to phase-in the implementation of the Green Gas program over a multi-year period in order to confirm market interest, demonstrate the ability of producers to deliver a reliable supply of Biomethane, and to verify that processes supporting the business model function effectively, while ensuring costs of supply are recovered by customers who opt into the program. The phased rollout is described in Section 6.

[1] While not previously mentioned in Section 4, The Company's research of other green pricing programs elsewhere in North found that the majority of green pricing programs offered by utilities have open entry and exit dates for residential customers. This source for this data is: EIA, http://www.eia.doe.gov/cneaf/electricity/epm/table5_6_b.html

Appendix F

PROPOSED TARIFFS

BILLING

Definitions

Unless the context indicates otherwise, in the General Terms and Conditions of Terasen Gas and in the rate schedules of Terasen Gas the following words have the following meanings:

Basic Charge Means a fixed charge required to be paid by a Customer for Service during a prescribed period as specified in the applicable Rate Schedule.

Biogas Means raw gas substantially composed of methane that is produced by the breakdown of organic matter in the absence of oxygen.

Biomethane Means Biogas purified or upgraded to pipeline quality gas.

Biomethane Service Means the Service provided to Customers under Rate Schedules 1B for Residential Biomethane Service, 2B for Small Commercial Biomethane Service, 3B for Large Commercial Biomethane Service, 11B for Large Volume Interruptible Biomethane Service, and 30 for Off-system Interruptible Sales

British Columbia Utilities Commission Means the British Columbia Utilities Commission constituted under the *Utilities Commission Act* of British Columbia and includes and is also a reference to

(i) any commission that is a successor to such commission, and

(ii) any commission that is constituted pursuant to any statute that may be passed which supplements or supersedes the *Utilities Commission Act* of British Columbia

Carbon Offsets Means what Terasen Gas will purchase as a mechanism to balance demand-supply for Biomethane in the event of an undersupply of Biomethane in order to retain the greenhouse gas reductions that Customers would have received from Biomethane supply. One Carbon Offset represents the reduction of one metric ton of carbon dioxide or its equivalent in other greenhouse gases.

Commercial Service Means the provision of firm Gas supplied to one Delivery Point and through one Meter Set for use in approved appliances in commercial, institutional or small industrial operations.

Commodity Cost Recovery Charge Is as defined in the Table of Charges of the various Terasen Gas Rate Schedules.

Delivery Pressure	Means the pressure of the Gas at the Delivery Point.
First Nations	Means those First Nations that have attained legally recognized self-government status pursuant to self-government agreements entered into with the Federal Government and validly enacted self-government legislation in Canada.
Franchise Fees	Means the aggregate of all monies payable by Terasen Gas to a municipality or First Nations (i) for the use of the streets and other property to construct and operate the utility business of Terasen Gas within a municipality or First Nations lands (formerly, reserves within the *Indian Act*), (ii) relating to the revenues received by Terasen Gas for Gas consumed within the municipality or First Nations lands (formerly, reserves within the *Indian Act*), and (iii) relating, if applicable, to the value of Gas transported by Terasen Gas through the municipality or First Nations lands (formerly, reserves within the *Indian Act*).
Gas	Means natural gas (including odorant added by Terasen Gas). propane and Biomethane.
Gas Service	Means the delivery of Gas through a Meter Set.
General Terms & Conditions of Terasen Gas	Means these general terms and conditions of Terasen Gas from time to time approved by the British Columbia Utilities Commission.
Gigajoule	Means a measure of energy equal to one billion joules used for billing purposes.
Heat Content	Means the quantity of energy per unit volume of Gas measured under standardized conditions and expressed in megajoules per cubic metre (MJ/m^3).
Hour	Means any consecutive 60 minute period.
Hydronic Heating System	A heating / cooling system where water is heated or cooled and distributes hot water through pipes to radiators or to another style of water-to-air heat exchanger.
Landlord	A Person who, being the owner of a property, has leased or rented it to another person, called the Tenant, and includes the agent of that owner.

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28. Biomethane Service

28.1 **Notional Gas** – Customers agree and recognize that the location of generation facilities will determine where Biomethane will physically be introduced to the Terasen Gas System and that Customers receiving Biomethane Service may not receive actual Biomethane at their Premises, but instead be contributing to the cost for Terasen Gas to deliver an amount of Biomethane proportionate to the Customer's Gas usage into the Terasen Gas System.

28.2 **Biomethane Physical Delivery** – Customers located in the vicinity of Biomethane generation facilities may receive Biomethane as a component of Gas in such proportion as Terasen Gas determines in its sole discretion.

28.3 **Reduced Supply** – Customers agree and recognize that the production of Biomethane is subject to biological processes and production levels may fluctuate. Customers registered for Biomethane Service for applicable Rate Schedules 1B, 2B and 3B, agree that in the event that Biomethane production does not provide sufficient gas supply, Terasen Gas may purchase Carbon Offsets in an amount equivalent to the greenhouse gas reduction that would have been achieved through Biomethane supply, and at a price not to exceed the funding received from Customers registered for Biomethane Service.

28.4 **Price Determination** - Customers registered for Biomethane Service will be billed for Gas pursuant to their applicable Rate Schedule. The cost of Biomethane will be based on the cost of acquiring Biomethane, including, but not limited to commodity, production, infrastructure, equipment and operating costs required to deliver pipeline quality Gas.

28.5 **Biomethane Customers** - Customers registered for Biomethane Service will be charged a Biomethane Energy Recovery Charge based on a calculation that will deem the Customer's Gas usage to be a pre-determined percentage of Biomethane and a pre-determined percentage of conventionally sourced Gas. Applicable Rate Schedules will be reviewed and updated quarterly with regard to the price of conventionally sourced Gas and annually with regard to the price of Biomethane with rate changes subject to BCUC approval.

28.6 **Enrolment** - In the event a Customer enters into a Service Agreement with Terasen Gas for Biomethane Service under Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B, the following terms and conditions will apply:

(a) **Notice** - the Customer will provide notification to Terasen Gas that he or she wishes to receive Biomethane Service, and Terasen Gas will provide confirmation to the Customer once the Customer is registered for Biomethane Service.

(b) **Eligibility** - the number of Customers eligible to receive Biomethane Service will be limited and the determination of eligibility will be made by Terasen Gas in its discretion, acting reasonably.

(c) **Change in Rate** - Customers registered for Biomethane Service will be charged for Gas at the rates set out in Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B. Terasen Gas will use reasonable efforts to switch Customers to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B in a timely manner. However, Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B rates will only be commenced on the first day of a Month; therefore, Customers registered for Biomethane Service within one (1) week on the last day of a Month may not be switched to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B until five (5) weeks after their registration date.

(d) **Biomethane Service Area** – Biomethane Service is available in all Terasen Gas Service Areas except the Municipality of Revelstoke

(e) **Moving** – If a Customer registered for Biomethane Service moves to new Premises within the Biomethane Service Area described above, that Customer may remain registered for Biomethane Service at the new Premises.

(f) **Switching Back to Terasen Gas Standard Rate Schedule** – Customers may at any time request to terminate Biomethane Service and be returned to a Terasen Gas conventional Gas Rate Schedule. On receiving notice that a Customer wishes to return to conventional Gas Service, Terasen Gas will return that Customer to the applicable Terasen Gas conventional Gas Rate Schedule in accordance with the Terasen Gas General Terms and Conditions.

(g) **Switching to a Gas Marketer Contract** – Customers may at any time request to terminate Biomethane Service and receive their commodity from a Gas Marketer. On receiving notice that a Customer has entered into an agreement with a Gas Marketer, Terasen Gas will process this request in accordance with Section 27.

(h) **Program Termination** – Terasen Gas reserves the right to remove and/or terminate Customers from Biomethane Service at any time.

BILLING

Definitions

Unless the context indicates otherwise, in the General Terms and Conditions of Terasen Gas and in the rate schedules of Terasen Gas the following words have the following meanings:

Basic Charge	Means a fixed charge required to be paid by a Customer for Service during a prescribed period as specified in the applicable Rate Schedule.
Biogas	Means raw gas substantially composed of methane that is produced by the breakdown of organic matter in the absence of oxygen.
Biomethane	Means Biogas purified or upgraded to pipeline quality gas.
Biomethane Service	Means the Service provided to Customers under Rate Schedules 1B for Residential Biomethane Service, 2B for Small Commercial Biomethane Service, 3B for Large Commercial Biomethane Service, 11B for Large Volume Interruptible Biomethane Service, and 30 for Off-System Interruptible Biomethane Sales
British Columbia Utilities Commission	Means the British Columbia Utilities Commission constituted under the *Utilities Commission Act* of British Columbia and includes and is also a reference to (i) any commission that is a successor to such commission, and (ii) any commission that is constituted pursuant to any statute that may be passed which supplements or supersedes the *Utilities Commission Act* of British Columbia
Carbon Offsets	Means what Terasen Gas will purchase as a mechanism to balance demand-supply for Biomethane in the event of an undersupply of Biomethane in order to retain the greenhouse gas reductions that Customers would have received from Biomethane supply. One Carbon Offset represents the reduction of one metric ton of carbon dioxide or its equivalent in other greenhouse gases.
Commercial Service	Means the provision of firm Gas supplied to one Delivery Point and through one Meter Set for use in approved appliances in commercial, institutional or small industrial operations.
Commodity Cost Recovery Charge	Is as defined in the Table of Charges of the various Terasen Gas Rate Schedules.

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Commodity Unbundling Service	Means the service provided to Customers under Rate Schedule 1U for Residential Unbundling Service, Rate Schedule 2U for Small Commercial Commodity Unbundling Service and Rate Schedule 3U for Large Commercial Commodity Unbundling Service.
Conversion Factor	Means a factor, or combination of factors, which converts gas meter data to Gigajoules or cubic metres for billing purposes.
Customer	Means a Person who is being provided Service or who has filed an application for Service with Terasen Gas that has been approved by Terasen Gas.
Day	Means any period of 24 consecutive Hours beginning and ending at 7:00 a.m. Pacific Standard Time or as otherwise specified in the Service Agreement.
Delivery Point	Means the outlet of the Meter Set unless otherwise specified in the Service Agreement.
Delivery Pressure	Means the pressure of the Gas at the Delivery Point.
First Nations	Means those First Nations that have attained legally recognized self-government status pursuant to self-government agreements entered into with the Federal Government and validly enacted self-government legislation in Canada.
Franchise Fees	Means the aggregate of all monies payable by Terasen Gas to a municipality or First Nations (i) for the use of the streets and other property to construct and operate the utility business of Terasen Gas within a municipality or First Nations lands (formerly, reserves within the *Indian Act*), (ii) relating to the revenues received by Terasen Gas for Gas consumed within the municipality or First Nations lands (formerly, reserves within the *Indian Act*), and (iii) relating, if applicable, to the value of Gas transported by Terasen Gas through the municipality or First Nations lands (formerly, reserves within the *Indian Act*).
Gas	Means natural gas (including odorant added by Terasen Gas), propane and Biomethane. C
Gas Service	Means the delivery of Gas through a Meter Set.

28. Biomethane Service

28.1 **Notional Gas** - Customers agree and recognize that the location of generation facilities will determine where Biomethane will physically be introduced to the Terasen Gas System and that Customers receiving Biomethane Service may not receive actual Biomethane at their Premises, but instead be contributing to the cost for Terasen Gas to deliver an amount of Biomethane proportionate to the Customer's Gas usage into the Terasen Gas System.

28.2 **Biomethane Physical Delivery** - Customers located in the vicinity of Biomethane generation facilities may receive Biomethane as a component of Gas in such proportion as Terasen Gas determines in its sole discretion.

28.3 **Reduced Supply** - Customers agree and recognize that the production of Biomethane is subject to biological processes and production levels may fluctuate. Customers registered for Biomethane Service for applicable Rate Schedules 1B, 2B and 3B, agree that in the event that Biomethane production does not provide sufficient gas supply, Terasen Gas may purchase Carbon Offsets in an amount equivalent to the greenhouse gas reduction that would have been achieved through Biomethane supply, and at a price not to exceed the funding received from Customers registered for Biomethane Service. N

28.4 **Price Determination** - Customers registered for Biomethane Service will be billed for Gas pursuant to their applicable Rate Schedule. The cost of Biomethane will be based on the cost of acquiring Biomethane, including, but not limited to commodity, production, infrastructure, equipment and operating costs required to deliver pipeline quality Gas.

28.5 **Biomethane Customers** - Customers registered for Biomethane Service will be charged a Biomethane Energy Recovery Charge based on a calculation that will deem the Customer's Gas usage to be a pre-determined percentage of Biomethane and pre-determined percentage of conventionally sourced Gas. Applicable Rate Schedules will be reviewed and updated quarterly with regard to the price of conventionally sourced Gas and annually with regard to the price of Biomethane with rate changes subject to BCUC approval.

28.6 **Enrolment** - In the event a Customer enters into a Service Agreement with Terasen Gas for Biomethane Service under Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B, the following terms and conditions will apply:

(a) **Notice** - the Customer will provide notification to Terasen Gas that he or she wishes to receive Biomethane Service, and Terasen Gas will provide confirmation to the Customer once the Customer is registered for Biomethane Service.

(b) **Eligibility** - the number of Customers eligible to receive Biomethane Service will be limited and the determination of eligibility will be made by Terasen Gas in its discretion, acting reasonably.

(c) **Change in Rate** - Customers registered for Biomethane Service will be charged for Gas at the rates set out in Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B. Terasen Gas will use reasonable efforts to switch Customers to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B in a timely manner. However, Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B rates will only be commenced on the first day of a Month, therefore, Customers registered for Biomethane Service within one (1) week on the last day of a Month may not be switched to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B until five (5) weeks after their registration date.

N

(d) **Biomethane Service Area** - Biomethane Service is available in all Terasen Gas Service Areas except the Municipality of Revelstoke.

(e) **Moving** - If a Customer registered for Biomethane Service moves to new Premises within the Biomethane Service Area described above, that Customer may remain registered for Biomethane Service at the new Premises.

(f) **Switching Back to Terasen Gas Standard Rate Schedule** - Customers may at any time request to terminate Biomethane Service and be returned to a Terasen Gas conventional Gas Rate Schedule. On receiving notice that a Customer wishes to return to conventional Gas Service, Terasen Gas will return that Customer to the applicable Terasen Gas conventional Gas Rate Schedule in accordance with the Terasen Gas General Terms and Conditions.

(g) **Switching to a Gas Marketer Contract** - Customers may at any time request to terminate Biomethane Service and receive their commodity from a Gas Marketer. On receiving notice that a Customer has entered into an agreement with a Gas Marketer, Terasen Gas will process this request in accordance with Section 27.

(h) **Program Termination** - Terasen Gas reserves the right to remove and/or terminate Customers from Biomethane Service at any time.

TABLE OF CONTENTS

Section **Page**

8. Insert the following additional sentence at the end of Article 10.6:

   "The Non-Defaulting Party's rights under this Contract are in addition to and not in limitation or exclusion of any other rights the Non-Defaulting Party may have (whether by contract, operation of law, or otherwise."

9. Insert the following additional sentence as Article 11.6:

   "In the event of non-performance due to Force Majeure, the affected party shall, to the extent permitted by the Transporters, prorate all Firm obligations at the affected Delivery Point and shall give Firm obligations priority over all Interruptible obligations."

10. Replace Section 13.5 with the following:

    "The interpretation and performance of this Contract shall be governed by the laws of the Province specified by the parties in the Base Contract, excluding, however, any conflict of laws rule which would apply the law of another jurisdiction, and the parties hereby attorn to the exclusive jurisdiction of the courts of the Province of British Columbia."

11. Replace Section 13.6 with the following:

    "This Contract and all provisions herein will be subject to all applicable and valid statutes, rules, orders and regulations of any Federal, Provincial, State, or local governmental authority having jurisdiction over the parties, their facilities, or Gas Supply, this Contract or Transaction Confirmation or any provisions thereof."

12. Insert the following as Article 13.11:

    "The terms of this Contract, including but not limited to the purchase price, the Transporter(s), and cost of transportation, and the quantity of Gas purchased or sold, shall be kept confidential by the parties, except as required by law or for the purpose of effectuating transportation of Gas pursuant to this Agreement."

13. Insert the following as Article 13.12:

    "Time is of Essence – Time is of the essence of this Contract and the terms and conditions thereof."

14. Replace the following in Section 2:

    ""Gas" shall mean any mixture of hydrocarbons and non-combustible gases in gaseous state consisting primarily of methane, including biomethane."

Transaction Confirmation

Transaction Confirmation to the Gas EDI between __________________ and Terasen Gas Inc. entered into __________________.

This confirms our Transaction on the following terms and conditions. The terms and conditions below will be final and binding in accordance with Terms and Conditions of the above referenced contract.

Date: ________________ **Transaction Type:** Interruptible **Transaction #** __________

Buyer:	**Seller:**
Marketing rep:	Terasen Gas Inc. Marketing rep:

Transaction Details

Start Date	End Date	Quantity	Commodity Price	Delivery Point	Delivery Pipe
		_____ Mmbtu	_____$US/MMBTU	Huntington	DEGT-BC

Special Terms and Conditions:

Comments

Terasen Gas Inc. certifies that the gas sold under this confirmation notice is **BIOMETHANE** (description may need to be altered to conform to buyer's regulatory requirement)

Transportation to the delivery point is included in the Commodity Price.

TERASEN GAS INC.	______________________________ (Marketer)
______________________________	______________________________
Date ______________________	Date ______________________

TABLE OF CONTENTS

Section **Page**

8. Insert the following additional sentence at the end of Article 10.6:

   "The Non-Defaulting Party's rights under this Contract are in addition to and not in limitation or exclusion of any other rights the Non-Defaulting Party may have (whether by contract, operation of law, or otherwise."

9. Insert the following additional sentence as Article 11.6:

   "In the event of non-performance due to Force Majeure, the affected party shall, to the extent permitted by the Transporters, prorate all Firm obligations at the affected Delivery Point and shall give Firm obligations priority over all Interruptible obligations."

10. Replace Section 13.5 with the following:

    "The interpretation and performance of this Contract shall be governed by the laws of the Province specified by the parties in the Base Contract, excluding, however, any conflict of laws rule which would apply the law of another jurisdiction, and the parties hereby attorn to the exclusive jurisdiction of the courts of the Province of British Columbia."

11. Replace Section 13.6 with the following:

    "This Contract and all provisions herein will be subject to all applicable and valid statutes, rules, orders and regulations of any Federal, Provincial, State, or local governmental authority having jurisdiction over the parties, their facilities, or Gas Supply, this Contract or Transaction Confirmation or any provisions thereof."

12. Insert the following as Article 13.11:

    "The terms of this Contract, including but not limited to the purchase price, the Transporter(s), and cost of transportation, and the quantity of Gas purchased or sold, shall be kept confidential by the parties, except as required by law or for the purpose of effectuating transportation of Gas pursuant to this Agreement."

13. Insert the following as Article 13.12:

    "Time is of Essence – Time is of the essence of this Contract and the terms and conditions thereof."

14. Replace the following in Section 2:

    ""Gas" shall mean any mixture of hydrocarbons and non-combustible gases in a gaseous state consisting primarily of methane, including biomethane." N

Transaction Confirmation

Transaction Confirmation to the Gas EDI between ________________ and Terasen Gas Inc. entered into ________________.

This confirms our Transaction on the following terms and conditions. The terms and conditions below will be final and binding in accordance with Terms and Conditions of the above referenced contract.

Date: ______________ **Transaction Type:** Interruptible **Transaction #** _________

Buyer:	**Seller:**
Marketing rep:	Terasen Gas Inc. Marketing rep:

Transaction Details

N

Start Date	End Date	Quantity	Commodity Price	Delivery Point	Delivery Pipe
		_____ Mmbtu	_____$US/MMBTU	Huntington	DEGT-BC

Special Terms and Conditions:

Comments

Terasen Gas Inc. certifies that the gas sold under this confirmation notice is **BIOMETHANE** (description may need to be altered to conform to buyer's regulatory requirement)

Transportation to the delivery point is included in the Commodity Price.

TERASEN GAS INC.	______________________________ (Marketer)
______________________________	______________________________
Date ______________________________	Date ______________________________

TERASEN GAS INC.

RATE SCHEDULE 1B
RESIDENTIAL BIOMETHANE SERVICE

Rate Schedule 1B: Residential Biomethane Service

Available

This Rate Schedule is available in all territory served by Terasen Gas, with the exception of the Municipality of Revelstoke, provided adequate capacity exists in Terasen Gas' system. Entry dates for commencing service under this Rate Schedule shall be the first day of each month following October 1, 2010. The number of Customers that may enrol in Residential Biomethane Service for a given entry date may be limited. In the event that there is a limit to the total number of Customers that may be enrolled in Biomethane Service under this Rate Schedule for a particular entry date, enrolments will be processed on a "first come, first served" basis.

Applicable

This Rate Schedule is applicable to firm Gas supplied at one Premises for use in approved appliances for all residential applications in single-family residences, separately metered single-family townhouses, rowhouses, condominiums, duplexes and apartments and single metered apartment blocks with four or less apartments. Customers who are currently disconnected are not eligible to enrol. Customers who are currently enrolled in Commodity Unbundling Service under Rate Schedule 1U are ineligible to enrol until their existing contract term with their gas marketer expires.

Table of Charges

	Lower Mainland Service Area	Inland Service Area	Columbia Service Area
Delivery Margin Related Charges			
1. **Basic Charge** per Month	**$ 11.84**	**$ 11.84**	**$ 11.84**
2. Delivery Charge per Gigajoule	$ 3.179	$ 3.179	$ 3.179
3. Rider 2 per Gigajoule	$ 0.059	$ 0.059	$ 0.059
4. Rider 3 per Gigajoule	$ (0.040)	$ (0.040)	$ (0.040)
5. Rider 5 per Gigajoule	$ (0.053)	$ (0.053)	$ (0.053)
Subtotal of per Gigajoule **Delivery** Margin Related Charges	**$ 3.145**	**$ 3.145**	**$ 3.145**
Commodity Related Charges			
6. Midstream Cost Recovery Charge per Gigajoule	$ 1.642	$ 1.621	$ 1.681
7. Rider 8 per Gigajoule	$ 0.083	$ 0.083	$ 0.083
Subtotal of per Gigajoule **Midstream** Cost Recovery Related Charges	**$ 1.725**	**$ 1.704**	**$ 1.764**
8. **Cost of Gas** (Commodity Cost Recovery Charge) per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
9. **Cost of Biomethane**[1] (Biomethane Energy Recovery Charge) per Gigajoule	$ 9.224	$ 9.224	$ 9.224
Subtotal of per Gigajoule **Commodity** Cost Recovery Related Charges[2]	**$ X.XXX**	**$ X.XXX**	**$ X.XXX**

Delivery Margin Related Riders

Rider 2 **Recovery of July to December 2009 Approved Return on Equity and Capital Structure** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers for the period January 1, 2010 to December 31, 2010.

Rider 3 **Earnings Sharing Mechanism** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers.

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers.

Midstream Cost Recovery Related Riders

Rider 8 **Recovery of Commodity Unbundling Deferral Costs** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers, excluding Revelstoke.

Franchise Fee Charge of 3.09% of the aggregate of the above charges, including the Commodity Cost Recovery Charge, is payable (in addition to the above charges) if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which Terasen Gas pays Franchise Fees.

Minimum Charge per Month - The minimum charge per Month will be the aggregate of the Basic Charge and the Franchise Fee Charge.

Notes:

1. Biomethane is acquired from a variety of sources and the Cost of Biomethane includes costs of acquiring Biomethane, including commodity, production, infrastructure, equipment and operating costs required to delivery system-quality methane gas.

2. The Subtotal of the per Gigajoule Commodity Cost Recovery Related Charges is based on the calculation of 90% of the Cost of Gas (Commodity Cost Recovery Charge) per Gigajoule added to the calculation of 10% of the Cost of Biomethane (Biomethane Energy Recovery Charge) per Gigajoule.

TERASEN GAS INC.

RATE SCHEDULE 2B
SMALL COMMERCIAL BIOMETHANE SERVICE

Rate Schedule 2B: Small Commercial Biomethane Service

Available

This Rate Schedule is available in all territory served by Terasen Gas, with the exception of the Municipality of Revelstoke, provided adequate capacity exists in Terasen Gas' system. Entry dates for commencing service under this Rate Schedule shall be the first day of each month following October 1, 2010. The number of Customers that may enrol in Biomethane Service for a given entry date may be limited. In the event that there is a limit to the total number of Customers that may be enrolled in Biomethane Service under this Rate Schedule for a particular entry date, enrolments will be processed on a "first come, first served" basis.

Applicable

This Rate Schedule is applicable to Customers with a normalized annual consumption at one Premises of less than 2,000 Gigajoules of firm Gas, for use in approved appliances in commercial, institutional or small industrial operations. Customers who are currently disconnected are not eligible to enrol. Customers who are currently enrolled in Commodity Unbundling Service under Rate Schedule 2U are ineligible to enrol until their existing contract term with their gas marketer expires.

Table of Charges

	Lower Mainland Service Area	Inland Service Area	Columbia Service Area
Delivery Margin Related Charges			
1. **Basic Charge** per Month	**$ XX.XX**	**$ XX.XX**	**$ XX.XX**
2. Delivery Charge per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
3. Rider 3 per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
4. Rider 5 per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
Subtotal of per Gigajoule **Delivery** Margin Related Charges	**$ X.XXX**	**$ X.XXX**	**$ X.XXX**
Commodity Related Charges			
5. Midstream Cost Recovery Charge per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
6. Rider 8 per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
Subtotal of per Gigajoule **Midstream** Cost Recovery Related Charges	**$ X.XXX**	**$ X.XXX**	**$ X.XXX**
7. **Cost of Gas** (Commodity Cost Recovery Charge) per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
8. **Cost of Biomethane**[1] (Biomethane Energy Recovery Charge) per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
Subtotal of per Gigajoule **Commodity** Cost Recovery Related Charges[2]	**$ X.XXX**	**$ X.XXX**	**$ X.XXX**

Delivery Margin Related Riders

Rider 3 **Earnings Sharing Mechanism** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers.

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers.

Midstream Cost Recovery Related Riders

Rider 8 **Recovery of Commodity Unbundling Deferral Costs** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers, excluding Revelstoke.

Franchise Fee Charge of 3.09% of the aggregate of the above charges, including the Commodity Cost Recovery Charge, is payable (in addition to the above charges) if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which Terasen Gas pays Franchise Fees.

Minimum Charge per Month - The minimum charge per Month will be the aggregate of the Basic Charge and the Franchise Fee Charge.

Notes:

1. Biomethane is acquired from a variety of sources and the Cost of Biomethane includes costs of acquiring Biomethane, including commodity, production, infrastructure, equipment and operating costs required to delivery system-quality methane gas.

2. The Subtotal of the per Gigajoule Commodity Cost Recovery Related Charges is based on the calculation of 90% of the Cost of Gas (Commodity Cost Recovery Charge) per Gigajoule added to the calculation of 10% of the Cost of Biomethane (Biomethane Energy Recovery Charge) per Gigajoule.

TERASEN GAS INC.

RATE SCHEDULE 3B
LARGE COMMERCIAL BIOMETHANE SERVICE

Rate Schedule 3B: Large Commercial Biomethane Service

Available

This Rate Schedule is available in all territory served by Terasen Gas, with the exception of the Municipality of Revelstoke, provided adequate capacity exists in Terasen Gas' system. Entry dates for commencing service under this Rate Schedule shall be the first day of each month following October 1, 2010. The number of Customers that may enrol in Biomethane Service for a given entry date may be limited. In the event that there is a limit to the total number of Customers that may be enrolled in Biomethane Service under this Rate Schedule for a particular entry date, enrolments will be processed on a "first come, first served" basis.

Applicable

This Rate Schedule is applicable to Customers with a normalized annual consumption at one Premises of greater than 2,000 Gigajoules of firm Gas, for use in approved appliances in commercial, institutional or small industrial operations. Customers who are currently disconnected are not eligible to enrol. Customers who are currently enrolled in Commodity Unbundling Service under Rate Schedule 3U are ineligible to enrol until their existing contract term with their gas marketer expires.

Table of Charges

	Lower Mainland Service Area	Inland Service Area	Columbia Service Area
Delivery Margin Related Charges			
1. **Basic Charge** per Month	**$XXX.XX**	**$XXX.XX**	**$XXX.XX**
2. Delivery Charge per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
3. Rider 3 per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
4. Rider 5 per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
Subtotal of per Gigajoule **Delivery** Margin Related Charges	**$ X.XXX**	**$ X.XXX**	**$ X.XXX**
Commodity Related Charges			
5. Midstream Cost Recovery Charge per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
6. Rider 8 per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
Subtotal of per Gigajoule **Midstream** Cost Recovery Related Charges	**$ X.XXX**	**$ X.XXX**	**$ X.XXX**
7. **Cost of Gas** (Commodity Cost Recovery Charge) per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
8. **Cost of Biomethane**[1] (Biomethane Energy Recovery Charge) per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
Subtotal of per Gigajoule **Commodity** Cost Recovery Related Charges[2]	**$ X.XXX**	**$ X.XXX**	**$ X.XXX**

Delivery Margin Related Riders

Rider 3 **Earnings Sharing Mechanism** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers.

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to Lower Mainland, Inland and Columbia Service Area.

Midstream Cost Recovery Related Riders

Rider 8 **Recovery of Commodity Unbundling Deferral Costs** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers, excluding Revelstoke.

Franchise Fee Charge of 3.09% of the aggregate of the above charges, including the Commodity Cost Recovery Charge, is payable (in addition to the above charges) if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which Terasen Gas pays Franchise Fees.

Minimum Charge per Month - The minimum charge per Month will be the aggregate of the Basic Charge and the Franchise Fee Charge.

Notes:

1. Biomethane is acquired from a variety of sources and the Cost of Biomethane includes costs of acquiring Biomethane, including commodity, production, infrastructure, equipment and operating costs required to delivery system-quality methane gas.

2. The Subtotal of the per Gigajoule Commodity Cost Recovery Related Charges is based on the calculation of 90% of the Cost of Gas (Commodity Cost Recovery Charge) per Gigajoule added to the calculation of 10% of the Cost of Biomethane (Biomethane Energy Recovery Charge) per Gigajoule.

TERASEN GAS INC.

RATE SCHEDULE 11B
BIOMETHANE LARGE VOLUME INTERRUPTIBLE SALES

Effective October 1, 2010

TABLE OF CONTENTS

Section **Page**

1. Definitions

1.1 **Definitions** - Except where the context requires otherwise all words and phrases defined below or in the General Terms and Conditions of Terasen Gas and used in this Rate Schedule or in a Transportation Agreement have the meanings set out below or in the General Terms and Conditions of Terasen Gas. Where any of the definitions set out below conflict with the definitions in the General Terms and Conditions of Terasen Gas, the definitions set out below govern.

(a) **Commencement Date** - means the day specified as the Commencement Date in the Sales Agreement, as the context requires.

(b) **Customer** - means for the purposes of this Rate Schedule 11B, the entity entering into this Rate Schedule 11B with Terasen Gas whether that entity is a Shipper or a Shipper Agent.

(c) **Day** - means any period of 24 consecutive Hours beginning and ending at 7:00 a.m. Pacific Standard Time or as otherwise specified in the Service Agreement.

(d) **Group** - means a group of Shippers who each transport Gas under transportation Rate Schedule, have a common Shipper Agent, and who have each entered into a Transportation Agreement.

(e) **Point of Sale** - the point of sale shall be from Terasen Gas certified Biomethane facilities attached to the Terasen Gas distribution system.

(f) **Sales Agreement** - means an agreement between Terasen Gas and the Customer for the sale of Biomethane pursuant to this Rate Schedule; a Biomethane Large Volume Interruptible Sales Agreement.

(g) **Shipper** - means a person who enters into a Transportation Agreement with Terasen Gas.

(h) **Shipper Agent** - means a person who enters into a Shipper Agent Agreement with Terasen Gas.

(i) **Transportation Agreement** - means an agreement between Terasen Gas and a Shipper to provide service pursuant to a transportation Rate Schedule.

2. Applicability, Availability and Amendment

2.1 **Description of Applicability** - This Rate Schedule applies to the sale of interruptible Biomethane, at the Point of Sale, no portion of which may be resold, except for the case where the Customer is a Shipper Agent, in which case the Biomethane must be resold to one or more members of its Groups.

2.2 **Availability** - This Rate Schedule is available in all territory served by Terasen Gas, except for the Municipality of Revelstoke.

2.3 **British Columbia Utilities Commission** - This Rate Schedule may be amended from time to time with the consent of the British Columbia Utilities Commission.

3. Conditions of Sales

3.1 **Conditions** - Terasen Gas will only sell Biomethane to a Customer in the applicable territory served by Terasen Gas, under the Terasen Gas tariff of which this Rate Schedule is a part if:

(a) the Customer has entered into a Biomethane Large Volume Interruptible Sales Agreement ("Sales Agreement"),

(b) the Customer has entered into a Transportation Agreement pursuant to Rate Schedule 22, 22A, 22B, 23, 25 or 27; or all members of the Group which the Customer represents, if the Customer is a Shipper Agent, have entered into a Transportation Agreement under the applicable Rate Schedule, and

(c) adequate Biomethane volumes are available for sale by Terasen Gas to the Customer for the facilities specified in the Sales Agreement.

3.2 **Security** - In order to secure the prompt and orderly payment of the charges to be paid by the Customer to Terasen Gas under the Sales Agreement, Terasen Gas may require the Customer to provide, and at all times maintain, an irrevocable letter of credit in favour of Terasen Gas issued by a financial institution acceptable to Terasen Gas in an amount equal to the estimated maximum amount payable by the Customer under this Rate Schedule for a period of 90 Days. Where Terasen Gas requires a Customer to provide a letter of credit and the Customer is able to provide alternative security acceptable to Terasen Gas, Terasen Gas may accept such security in lieu of a letter of credit.

4. Terms of Sale

4.1 **Sale of Biomethane** - Subject to all of the terms and conditions set out in this Rate Schedule, Terasen Gas will sell to the Customer and the Customer will buy from Terasen Gas on each Day the quantity of Biomethane authorized by Terasen Gas in accordance with section 6 (Nomination).

4.2 **Curtailment** - Terasen Gas may at any time, for any reason and for any length of time, interrupt or curtail Biomethane sales under this Rate Schedule.

4.3 **Notice of Curtailment** - Each notice from Terasen Gas to the Customer with respect to the interruption or curtailment by Terasen Gas of deliveries of Biomethane will be by telephone and/or fax and will specify the quantity of Biomethane to which the Customer is curtailed and the time at which such curtailment is to be made. Terasen Gas will make reasonable efforts to give as much notice as possible with respect to such curtailment, not to be less than 2 Hours prior notice unless prevented by Force Majeure.

5. Table of Charges

5.1 **Charges** - In respect of all quantities of Biomethane sold to the Customer under this Rate Schedule, the Customer will pay to Terasen Gas all of the charges set out in the Table of Charges.

5.2 **Applicable Charges** - Charges under this Rate Schedule include Biomethane commodity cost and delivery cost of Biomethane over the Terasen Gas System. In addition, Customers shall be responsible for paying the Terasen Gas delivery charge as set out in a Customer's applicable transportation contract.

6. Nomination

6.1 **Requested Quantity** - The Customer will provide a nomination to Terasen Gas through the WINS (Web Information and Nomination System), by fax or other method approved by Terasen Gas, prior to 7:30 a.m. Local Time on each Day (or such other time as may be specified from time to time by Terasen Gas) the Customer's Requested Quantity for the Day commencing in approximately 24 Hours.

6.2 **Authorized Quantity** - Terasen Gas will each Day, determine the Authorized Quantity to be made available to the Customer under this Rate Schedule and will advise the Customer if such Authorized Quantity is less than the Customer's Requested Quantity.

7. Groups

7.1 **Notices To and From Shipper Agents** - If the Customer is a member of a Group then:

(a) communications regarding curtailments, interruptions, quantities of Biomethane requested and quantities of Biomethane authorized will be between the Shipper Agent for the Group and Terasen Gas,

(b) notices from Terasen Gas with respect to interruption or curtailment pursuant to section 4.3 (Notice of Curtailment) will be to the Shipper Agent for the Group and will specify the quantity of Biomethane to which the Group is curtailed and the time at which such curtailment is to be made; it will be the responsibility of the Shipper Agent to notify Customers which are members of the Group of interruptions or curtailments,

(c) the Shipper Agent will provide to Terasen Gas the Requested Quantity for the Group pursuant to section 6.1 (Requested Quantity) and if the Shipper Agent does not so notify Terasen Gas, then the Group's Requested Quantity for the Day commencing in approximately 24 Hours will be deemed to be the Group's quantity pursuant to section 6.2 (Authorized Quantity) for the Day just commencing, and

(d) Terasen Gas will each Day determine the Authorized Quantity to be made available to the Group under this Rate Schedule and will advise the Shipper Agent if such Authorized Quantity is less than the Group's Requested Quantity.

8. Term of Sales Agreement

8.1 **Term** - The initial term of the Sales Agreement will begin on the Commencement Date and, will expire at 7:00 a.m. Pacific Standard Time on the November 1st next following.

8.2 **Automatic Renewal** - Except as specified in the Sales Agreement, the term of the Sales Agreement will continue on a Year to Year basis after the expiry of the initial term until cancelled by either Terasen Gas or the Customer upon not less than 10 Days notice prior to the end of the Contract Year then in effect.

8.3 **Early Termination** - The term of the Sales Agreement is subject to early termination in accordance with section 12 (Default or Bankruptcy).

8.4 **Survival of Covenants** - Upon the termination of the Sales Agreement, whether pursuant to section 12 (Default or Bankruptcy) or otherwise,

(a) all claims, causes of action or other outstanding obligations remaining or being unfulfilled as at the date of termination, and

(b) all of the provisions in this Rate Schedule and in the Sales Agreement relating to the obligation of any of the parties to account to or indemnify the other and to pay to the other any monies owing as at the date of termination in connection with the Sales Agreement,

will survive such termination.

9. Indemnity and Limitation on Liability

9.1 **Limitation on Liability** - Terasen Gas, its employees, contractors or agents are not responsible or liable for any loss or damages for or on account of any interruption or curtailment of Biomethane sales permitted under the General Terms and Conditions of Terasen Gas or this Rate Schedule.

9.2 **Indemnity** - The Customer will indemnify and hold harmless each of Terasen Gas, its employees, contractors and agents from and against any and all adverse claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) arising from or out of each of the following:

(a) Franchise Fees not otherwise collected by Terasen Gas, under the Table of Charges, and

(b) all federal, provincial, municipal taxes (or payments made in lieu thereof) and royalties, whether payable on the delivery of Biomethane to the Customer by Terasen Gas or on the delivery of Biomethane to Terasen Gas by the Customer, or on any other service provided by Terasen Gas to the Customer.

9.3 **Principal Obligant** - The Customer entering into a Rate Schedule 11B Sales Agreement will be the principal obligant.

10. Statements and Payments

10.1 **Statements to be Provided** - Terasen Gas will, on or about the 15th day of each month, deliver to the Customer a statement for the preceding month showing the Gas quantities delivered to the Customer and the amount due. If the Customer is a member of a Group then the statement and the calculation of the amount due from the Customer will be based on information supplied by the Shipper Agent, or based on other information available to Terasen Gas, as set out in the Shipper Agent Agreement. Terasen Gas will, on or about the 45th day after the end of a Contract Year, deliver to the Customer a separate statement for the preceding Contract Year showing the amount required from the Customer in respect of any indemnity due under this Rate Schedule or a Sales Agreement. Any errors in any statement will be promptly reported to the other party as provided hereunder, and statements will be final and binding unless questioned within one year after the date of the statement.

10.2 **Payment and Interest** - Payment for the full amount of the statement, including federal, provincial and municipal taxes or fees applicable thereon, will be made to Terasen Gas at its Vancouver, British Columbia office, or such other place in Canada as it will designate, on or before the 1st business day after the 10th calendar day following the billing date. If the Customer fails or neglects to make any payment required under this Rate Schedule, or any portion thereof, to Terasen Gas when due, interest on the outstanding amount will accrue, at the rate of interest declared by the chartered bank in Canada principally used by Terasen Gas, for loans in Canadian dollars to its most creditworthy commercial borrowers payable on demand and commonly referred to as its "prime rate", plus:

(a) 2% from the date when such payment was due for the first 30 days that such payment remains unpaid and 5% thereafter until the same is paid where the Customer has not, during the immediately preceding 6-month period, failed to make any payment when due hereunder; or

(b) 5% from the date when such payment was due to and including the date the same is paid where the Customer has, during the immediately preceding 6-month period, failed to make any payment when due hereunder.

10.3 **Examination of Records** - Each of Terasen Gas and the Customer will have the right to examine at reasonable times the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, charge, computation or demand made pursuant to any provisions of this Rate Schedule or the Sales Agreement.

11. Measurement

11.1 **Unit of Volume** - The unit of volume of Gas for all purposes hereunder will be 1 cubic metre at a temperature of 15^{o} Celsius and an absolute pressure of 101.325 kilopascals.

11.2 **Determination of Volume** - Gas delivered hereunder will be metered using metering apparatus approved by the Standards Division, Industry Canada, Office of Consumer Affairs and the determination of standard volumes delivered hereunder will be in accordance with terms and conditions pursuant to the *Electricity and Gas Inspection Act* of Canada.

11.3 **Conversion to Energy Units** - In accordance with the *Electricity and Gas Inspection Act* of Canada, volumes of Gas delivered each Day will be converted to energy units by multiplying the standard volume by the Heat Content of each unit of Gas. Volumes will be specified in 10^3m^3 rounded to one decimal place and energy will be specified in Gigajoules rounded to the nearest Gigajoule.

12. Default or Bankruptcy

12.1 **Default** - If the Customer at any time fails or neglects

(a) to make any payment due to Terasen Gas or to any other person under this Rate Schedule or the Sales Agreement within 30 days after payment is due, or

(b) to correct any default of any of the other terms, covenants, agreements, conditions or obligations imposed upon it under this Rate Schedule or the Sales Agreement, within 30 days after Terasen Gas gives to the Customer notice of such default or, in the case of a default that cannot with due diligence be corrected within a period of 30 days, the Customer fails to proceed promptly after the giving of such notice with due diligence to correct the same and thereafter to prosecute the correcting of such default with all due diligence,

then Terasen Gas may in addition to any other remedy that it has, including the rights of Terasen Gas set out in sections 4.4 (Default Regarding Curtailment) and at its option and without liability therefore

(a) suspend further transportation service to the Customer and may refuse to deliver Gas to the Customer until the default has been fully remedied, and no such suspension or refusal will relieve the Customer from any obligation under this Rate Schedule or the Sales Agreement, or

(b) terminate the Sales Agreement, and no such termination of the Sales Agreement pursuant hereto will exclude the right of Terasen Gas to collect any amount due to it from the Customer for what would otherwise have been the remainder of the term of the Sales Agreement.

12.2 **Bankruptcy or Insolvency** - If the Customer becomes bankrupt or insolvent or commits or suffers an act of bankruptcy or insolvency or a receiver is appointed pursuant to a statute or under a debt instrument or the Customer seeks protection from the demands of its creditors pursuant to any legislation enacted for that purpose, Terasen Gas will have the right, at its sole discretion, to terminate the Sales Agreement by giving notice in writing to the Customer and thereupon Terasen Gas may cease further delivery of Gas to the Customer and the amount then outstanding for Gas provided under the Sales Agreement will immediately be due and payable by the Customer.

13. Notice

13.1 **Notice** - Any notice, request, statement or bill that is required to be given or that may be given under this Rate Schedule or under the Sales Agreement will, unless otherwise specified, be in writing and will be considered as fully delivered when mailed, personally delivered or sent by fax to the other in accordance with the following:

<u>if to Terasen Gas</u>	TERASEN GAS INC.	
MAILING ADDRESS:	16705 Fraser Highway Surrey, B.C. V4N 0E8	
NOMINATIONS AND FORCE MAJEURE:	Attention: Telephone: Fax:	Transportation Services Manager (604) 592-7788 (604) 592-7895
BILLING AND PAYMENT:	Attention: Telephone: Fax:	Industrial Billing (604) 663-3677 (604) 663-3683
CUSTOMER RELATIONS:	Attention: Telephone: Fax:	Commercial & Industrial Account Manager (604) 592-7843 (604) 592-7894

14. Force Majeure

14.1 **Force Majeure** - Subject to the other provisions of this section 14, if either party is unable or fails by reason of Force Majeure to perform in whole or in part any obligation or covenant set out in this Rate Schedule under which service is rendered or in the Sales Agreement, the obligations of both Terasen Gas and the Customer will be suspended to the extent necessary for the period of the Force Majeure condition.

14.2 **Curtailment Notice** - If Terasen Gas claims suspension pursuant to this section 14, Terasen Gas will be deemed to have issued to the Customer a notice of curtailment.

14.3 **Exceptions** - Neither party will be entitled to the benefit of the provisions of section 14.1 under any of the following circumstances

(a) to the extent that the failure was caused by the negligence or contributory negligence of the party claiming suspension,

(b) to the extent that the failure was caused by the party claiming suspension having failed to diligently attempt to remedy the condition and to resume the performance of the covenants or obligations with reasonable dispatch, or

(c) unless as soon as possible after the happening of the occurrence relied on or as soon as possible after determining that the occurrence was in the nature of Force Majeure and would affect the claiming party's ability to observe or perform any of its covenants or obligations under the Rate Schedule or the Sales Agreement, the party claiming suspension will have given to the other party notice to the effect that the party is unable by reason of Force Majeure (the nature of which will be specified) to perform the particular covenants or obligations.

14.4 **Notice to Resume** - The party claiming suspension will likewise give notice, as soon as possible after the Force Majeure condition has been remedied, to the effect that it has been remedied and that the party has resumed, or is then in a position to resume, the performance of the covenants or obligations.

14.5 **Settlement of Labour Disputes** - Notwithstanding any of the provisions of this section 14, the settlement of labour disputes or industrial disturbances will be entirely within the discretion of the particular party involved and the party may make settlement of it at the time and on terms and conditions as it may deem to be advisable and no delay in making settlement will deprive the party of the benefit of section 14.1.

14.6 **No Exemption for Payments** - Notwithstanding any of the provisions of this section 14, Force Majeure will not relieve or release either party from its obligations to make payments to the other.

14.7 **Periodic Repair by Terasen Gas** - Terasen Gas may temporarily shut off the delivery of Gas for the purpose of repairing or replacing a portion of the Terasen Gas System or its equipment and Terasen Gas will make reasonable efforts to give the Customer as much notice as possible with respect to such interruption. Terasen Gas will make reasonable efforts to schedule repairs or replacement to minimize interruption or curtailment of transportation service to the Customer, and to restore service as quickly as possible.

14.8 **Customer's Gas** - If Terasen Gas curtails or interrupts transportation of Gas by reason of Force Majeure the Customer will make its supply of Gas available to Terasen Gas, to the extent required by Terasen Gas, to maintain service priority to those customers or classes of customers which Terasen Gas determines should be served. Terasen Gas, in its sole discretion, will either increase the balance in the Customer's inventory account by the amount taken by Terasen Gas and return an equivalent quantity of Gas to the Customer as soon as reasonable, or pay the Customer an amount equal to either Terasen Gas' average Gas cost, or the Customer's average Gas cost, for the Day(s) during which such Gas was taken, whichever Gas cost the Customer, in its sole discretion, elects.

14.9 **Alteration of Facilities** - The Customer will pay to Terasen Gas all reasonable costs associated with the alteration of facilities made at the discretion of Terasen Gas to measure quantities reduced by reason of Force Majeure claimed by the Customer and to restore such facilities after the Force Majeure condition ends.

15. Mediation and Arbitration

15.1 **Mediation** - Where any dispute arises out of or in connection with this Rate Schedule or in a Sales Agreement, Terasen Gas and the Customer agree to try to resolve the dispute by participating in a structured mediation conference with a mediator under the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution.

15.2 **Arbitration** - If Terasen Gas and the Customer fail to resolve the dispute through mediation, the unresolved dispute shall be referred to, and finally resolved or determined by arbitration under the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution. Unless Terasen Gas and the Customer agree otherwise the arbitration will be conducted by a single arbitrator.

15.3 **Written Award** - The arbitrator shall issue a written award that sets forth the essential findings and conclusions on which the award is based. The arbitrator will allow discovery as required by law in arbitration proceedings.

15.4 **Failure to Render a Decision** - If the arbitrator fails to render a decision within thirty (30) days following the final hearing of the arbitration, any party to the arbitration may terminate the appointment of the arbitrator and a new arbitrator shall be appointed in accordance with these provisions. If Terasen Gas and the Customer are unable to agree on an arbitrator or if the appointment of an arbitrator is terminated in the manner provided for above, then either Terasen Gas or the Customer shall be entitled to apply to a judge of the British Columbia Supreme Court to appoint an arbitrator and the arbitrator so appointed shall proceed to determine the matter mutatis mutandis in accordance with the provisions of this section 15.

15.5 **Award** - The arbitrator shall have the authority to award:

(a) money damages;

(b) interest on unpaid amounts from the date due;

(c) specific performance; and

(d) permanent relief.

15.6 **Costs** - The costs and expenses of the arbitration, but not those incurred by the parties, shall be shared equally, unless the arbitrator determines that a specific party prevailed. In such a case, the non-prevailing party shall pay all costs and expenses of the arbitration, but not those of the prevailing party.

15.7 **Obligations Continue** - The parties will continue to fulfill their respective obligations pursuant to this Rate Schedule or in a Sales Agreement during the resolution of any dispute in accordance with this section 15.

16. Interpretation

16.1 **Interpretation** - Except where the context requires otherwise or except as otherwise expressly provided, in this Rate Schedule or in a Sales Agreement

(a) all references to a designated section are to the designated section of this Rate Schedule unless otherwise specifically stated,

(b) the singular of any term includes the plural, and vice versa, and the use of any term is equally applicable to any gender and, where applicable, body corporate,

(c) any reference to a corporate entity includes and is also a reference to any corporate entity that is a successor to such entity,

(d) all words, phrases and expressions used in this Rate Schedule or in a Sales Agreement that have a common usage in the gas industry and that are not defined in the General Terms and Conditions of Terasen Gas, the Definitions or in the Sales Agreement have the meanings commonly ascribed thereto in the gas industry, and

(e) the headings of the sections set out in this Rate Schedule or in the Sales Agreement are for convenience of reference only and will not be considered in any interpretation of this Rate Schedule or the Sales Agreement.

17. Miscellaneous

17.1 **Waiver** - No waiver by either Terasen Gas or the Customer of any default by the other in the performance of any of the provisions of this Rate Schedule or the Sales Agreement will operate or be construed as a waiver of any other or future default or defaults, whether of a like or different character.

17.2 **Enurement** - The Sales Agreement will enure to the benefit of and be binding upon the parties and their respective successors and permitted assigns, including without limitation successors by merger, amalgamation or consolidation.

17.3 **Assignment** - The Customer will not assign the Sales Agreement or any of its rights or obligations thereunder without the prior written consent of Terasen Gas which consent will not be unreasonably withheld or delayed. No assignment will release the Customer from its obligations under this Rate Schedule or under the Sales Agreement that existed prior to the date on which the assignment takes effect. This provision applies to every proposed assignment by the Customer.

17.4 **Amendments to be in Writing** - Except as set out in this Rate Schedule, no amendment or variation of the Sales Agreement will be effective or binding upon the parties unless such amendment or variation is set out in writing and duly executed by the parties.

17.5 **Proper Law** - The Sales Agreement will be construed and interpreted in accordance with the laws of the Province of British Columbia and the laws of Canada applicable therein.

17.6 **Time is of Essence** - Time is of the essence of this Rate Schedule, the Sales Agreement and of the terms and conditions thereof.

17.7 **Subject to Legislation** - Notwithstanding any other provision hereof, this Rate Schedule and the Sales Agreement and the rights and obligations of Terasen Gas and the Customer under this Rate Schedule and the Sales Agreement are subject to all present and future laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction over Terasen Gas or the Customer.

17.8 **Further Assurances** - Each of Terasen Gas and the Customer will, on demand by the other, execute and deliver or cause to be executed and delivered all such further documents and instruments and do all such further acts and things as the other may reasonably require to evidence, carry out and give full effect to the terms, conditions, intent and meaning of this Rate Schedule and the Sales Agreement and to assure the completion of the transactions contemplated hereby.

17.9 **Form of Payments** - All payments required to be made under statements and invoices rendered pursuant to this Rate Schedule or the Sales Agreement will be made by wire transfer to, or cheque or bank cashier's cheque drawn on a Canadian chartered bank or trust company, payable in lawful money of Canada at par in immediately available funds in Vancouver, British Columbia.

18. Title to Gas

18.1 **Representation and Warranty** - Terasen Gas represents and warrants the title to all Biomethane delivered to the Customer at the Point of Sale under this Rate Schedule and the right of Terasen Gas to sell such Biomethane, and represents and warrants that such Biomethane will be free and clear of all liens, encumbrances and claims.

18.2 **Transfer of Title** - Title to Biomethane sold under this Rate Schedule will pass to the Customer at the Point of Sale.

Table of Charges

	Lower Mainland Service Area	Inland Service Area
Cost of Biomethane[1] (Biomethane Energy Recovery Charge) per Gigajoule	$ X.XXX	$ X.XXX

Franchise Fee Charge of 3.09% of the aggregate of the above charges, is payable (in addition to the above charges) if the location of the facilities to which the Biomethane sold under this Rate Schedule is delivered is within the municipal boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which Terasen Gas pays Franchise Fees.

Notes:

1. Biomethane is acquired from a variety of sources and the Cost of Biomethane includes costs of acquiring Biomethane, including commodity, production, infrastructure, equipment and operating costs required to delivery system quality methane gas.

BIOMETHANE LARGE VOLUME INTERRUPTIBLE SALES AGREEMENT

This Agreement is dated _______________, 20___, between Terasen Gas Inc. ("Terasen Gas") and ________________________________ (the "Customer").

WHEREAS:

1.1 Terasen Gas owns and operates the Terasen Gas System;

1.2 The Customer or Shipper Agent for the Customer is the owner and operator of a ________________________________ located in or near _________________________, British Columbia; and

1.3 The Customer desires to purchase from Terasen Gas interruptible Biomethane for such facilities in accordance with Rate Schedule 11B and the terms set out herein.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the terms, conditions and limitations contained herein, the parties agree as follows:

1. Specific Information

Applicable Transportation Rate Schedule: ☐ 22 ☐ 22A ☐ 22B ☐ 23 ☐ 25 ☐ 27

Commencement Date: ____________________________________

Expiry Date: ____________________________________
(only specify expiry date if term not automatically renewed as set out in section 8.2 of Rate Schedule 11B)

Refer to Rate Schedule 22, 22A, 22B, 23, 25 or 27 Transportation Agreement for Address of Customer for receiving notices.

The information set out above is hereby approved by the parties and each reference in either this agreement or Rate Schedule 11B to any such information is to the information set out above.

2. Rate Schedule 11B

2.1 **Point of Delivery** - all Biomethane sales under this Sales Agreement will occur at the Point of Sale.

2.2 **Title Transfer** - Title Transfer to the Customer will occur at the Point of Sale.

2.3 **Additional Terms** - All rates, terms and conditions set out in Rate Schedule 11B and the General Terms and Conditions of Terasen Gas, as either of them may be amended by Terasen Gas and approved from time to time by the British Columbia Utilities Commission, are in addition to the terms and conditions contained in this Sales Agreement and form part of this Sales Agreement and bind Terasen Gas and the Customer as if set out herein.

2.4 **Payment of Amounts** - Without limiting the generality of the foregoing, the Customer will pay to Terasen Gas all of the amounts set out in Rate Schedule 11B for the services provided under that Rate Schedule and this Sales Agreement.

2.5 **Conflict** - Where anything in either Rate Schedule 11B, or the General Terms and Conditions of Terasen Gas, conflicts with any of the rates, terms and conditions set out in this Sales Agreement, this Sales Agreement governs. Where anything in Rate Schedule 11B conflicts with any of the rates, terms and conditions set out in the General Terms and Conditions of Terasen Gas, Rate Schedule 11B governs.

2.6 **Acknowledgment** - The Customer acknowledges receiving and reading a copy of Rates Schedule 11B and the General Terms and Conditions of Terasen Gas and agrees to comply with and be bound by all terms and conditions set out therein. Without limiting the generality of the foregoing, the Customer is able to accommodate interruption or curtailment of Biomethane sales and releases Terasen Gas from any liability for the Customer's inability to accommodate an interruption or curtailment of Biomethane sales.

IN WITNESS WHEREOF the parties hereto have executed this Sales Agreement.

TERASEN GAS INC.

BY: ______________________ (Signature)	BY: ______________________ (Signature)
______________________ (Title)	______________________ (Title)
______________________ (Name – Please Print)	______________________ (Name – Please Print)
DATE: ______________________	DATE: ______________________

Appendix G

PROGRAM COSTS

Program Cost Summary

As discussed in Section 6 and Section 10, Terasen Gas commissioned KnowledgeTech Consulting Inc. to assist in assessing the required business system changes (the “Project”) and estimates for the costs required to implement the new Green Gas program. The review included business process impacts and costs in various areas in order to implement the billing, tracking, reporting and management of a Green Gas program.

The scope of the Project included overall program management and solution architecture as well as the development, testing and deployment required to support updates, configuration and implementation of billing systems, processes and ongoing customer care operations to support a Green Gas program by CustomerWorks LP (“CWLP”). The below tables specifically outline program costs for the Green Gas program and do not include the cost of acquiring biogas, equipment or ongoing O&M associated with the equipment. Detailed financial schedules including these costs can be found in Appendix J 1-4.

Table G-1: Program Cost Impact: All Customers October 2010 – December 2010

Item	Est. # of Transactions	Estimate - One time	Estimated O&M*	TOTAL ANNUAL**
O&M - All Customers				
Oct 2010- Dec 2010				
Full Time Equivalent (FTE) – Biogas Program Manager			25,000	
Customer Education			160,000	
CWLP Application Support & Development		165,578		
Internal Reporting Changes			800	
Inbound Calls $1.33 per minute	1800-5400 mins / month		7,182	
TOTAL - All customers 2010		**$165,578**	**$192,982**	**$358,560**

*O&M costs have been shown as annual costs.
** 2010 costs have been pro-rated to reflect program launch in Oct 2010

Table G-2: Program Cost Impact: All Customers January 2011 – December 2011

Item	Est. # of Transactions	Estimate - One time	Estimated O&M*	TOTAL ANNUAL
O&M - All Customers				
Jan 2011 - Dec 2011				
FTE			100,000	
Customer Education			240,000	
Internal Reporting Changes			2,400	
Inbound Calls 1.33 per minute	1800-5400 mins / month		28,728	
Rate Changes quarterly update to biogas blended rate; assume $1000/quarter	quarterly update to biogas blended rate; assume $1000/quarter		4,000	
TOTAL - All customers 2011		**$0**	**$375,128**	**$375,128**

*O&M costs have been shown as annual costs.

Notes: Introduction of an additional biomethane tariff (e.g., 20% blend) or expansion to another rate class (e.g., Rate 2) prior to moving to in-house Customer Care would incur additional O&M charges of approximately $50,000 per new offering.

Table G-3: Program Cost Impact: All Customers 2012 Forward

Item	Est. # of Transactions	Estimate - One time	Estimated O&M*	TOTAL ANNUAL
2012 forward - All Customers				
FTE			100,000	
Customer Education			300,000	
Additional reporting from new CIS related to Biogas program.		10,000		
Rate setting and maintenance		-		
Inbound Calls $6.65 per call (assuming enrollments are processed as part of the call)	20% * enrollments		6,384	
		$10,000	**$406,384**	**$ 416,384**

*O&M costs have been shown as annual costs.

Table G-4: Program Cost Impact:
Green Gas Customers October 2010 - December 2010

Item	Est. # of Transactions	Estimate - One time	Estimated O&M*	TOTAL ANNUAL**
O&M - Green Gas Customers				
Oct 2010- Dec 2010				
Energy/Peace application support	7-15 hrs / month		4,656	
Enrollments automated; $0/txn	400-1200/month = 4800 - 14400/year		-	
Enrollment Confirmation (mailings) $1 per txn; 50% of enrollments via mail	200 - 600/month = 2400 - 7200/year		600	
Customer Drops/Finalizations/Moves/Adjustments/Callbacks 10.25 per txn	68-204/month = 816-2448/year		2,091	
Reporting & Admin	4 hrs/month		1,241	
Credits to customer bill for premises affected by heat content of biogas supply. Assume quarterly adjustment @$20 per transaction. 150 customers per supply point.	300		6,000	
TOTAL - Green Gas Customers - 2010			**$14,588**	**$14,588**

*O&M costs have been shown as annual costs.
** 2010 costs have been pro-rated to reflect program launch in Oct 2010

Table G-5: Program Cost Impact:
Green Gas Customers January 2011 - December 2011

Item	Est. # of Transactions	Estimate - One time	Estimated O&M*	TOTAL ANNUAL
O&M - Green Gas Customers				
Jan 2011- Dec 2011				
Energy/Peace application support	7-15 hrs/mth		18,624	
Enrollments automated; $0/txn	400-1200/month = 4800 - 14400/year		-	
Enrollment Confirmation (mailings) $1 per txn; 50% of enrollments via mail	200 - 600/month = 2400 - 7200/year		2,400	
Customer Drops/Finalizations/Moves/Adjustments/Callbacks 10.25 per txn	68-204/month = 816-2448/year		8,364	
Reporting & Admin	4 hrs/month		4,963	
Credits to customer bill for premises affected by heat content of biogas supply. 4 suppliers in 2011.	2400		48,000	
TOTAL - Green Gas Customers - 2011			**$82,351**	**$82,351**

*O&M costs have been shown as annual costs.

<u>Cost Assumptions:</u>

Assumptions made in providing the above cost estimates are as follows:

- Transactional costs are based on a customer uptake of 1% of eligible customers through 2011enrolling in the initial biogas offering of a 10% blend to Rate 1 customers.
- General inquiries will be approximately 20% of the actual number of customer enrolments
- Manual adjustments for premises in biogas heat zone will be done quarterly and are only required until the new CIS system is available (2012). Assume each biogas supply point may affect an average of 150 customers, with 2 supply points in 2010 growing to 4 supply points in 2011.

Table G-6: Program Cost Impact: Green Gas Customers 2012 Forward

Item	Est. # of Transactions	Estimate - One time	Estimated O&M*	TOTAL ANNUAL
2012 Forward - Green Gas Customers				
Application Support - new CIS		-		
Enrollments$6.65 per call; Assume phone in enrolments are processed as part of the call. Online enrolments will be automated; assume 50% are automated.	400-1200/month = 4800 - 14400/year		32,080	
Enrolment Confirmations$1 per enrolment; non-email only (includes paperstock, printing, mailing)	200 - 600/month = 2400 - 7200/year		4,824	
Customer moves/finals $0/txn; expect this process to be automated, so no additional cost	68-204/month = 816-2448/year			
Adjustment processing $0 / txn.				
Interface / process for updating premise heat zone in new CIS system for premises within proximity of biogas supply receipt point as determined by System Planning.		20,000		
TOTAL - Biogas Customers - 2012 forward		**$20,000**	**$36,904**	**$56,904**

*O&M costs have been shown as annual costs.

Appendix H

CUSTOMER EDUCATION PLAN

APPENDIX – H

1. Customer Education Plan

As described in Section 6.6.1, there are four objectives for the customer education efforts of the Green Gas program. They are to:

- generate awareness and understanding of biomethane as a renewable energy and its availability today;
- generate awareness and understanding of the Terasen Gas Green Gas program,
- stimulate interest and participation in the program; and
- maintain participation and support for the program.

Customer education will be an ongoing activity until the Green Gas program reaches a level of market maturity whereby customer groups who have access to the program are sufficiently aware of it and able to make an informed decision as to whether or not they wish to participate in it.

The customer education strategies address two distinct phases of the Terasen Gas Green Gas program: generating awareness, interest and subscriptions, and maintaining subscriptions.

Specifically, this Appendix will detail:

a) Generating awareness, interest and subscriptions
b) Key Messages
c) Customer Education Tactics
d) Customer Education Timeline

1.1. Generating awareness, interest and subscriptions

Communications will be targeted to those with the greatest likelihood of participation, using tactics, messages and channels that will be meaningful and relevant to the target audience's interests.

Target Audience

Those who are most likely to participate in the Terasen Gas Green Gas program are those who not only act in the interest of the environment, but also tend to be among the first to use new products and services. They routinely act on their concern about their environmental footprint in everything they do and buy; they are concerned about the current and future state of the environment and have taken steps to save energy in the past; they are innovators and early adopters of new products and services that benefit the environment.

Within this group, we will target opinion leaders who are well-regarded for their thoughts and opinions on environmental subjects. They are well-informed and engage in conversations about the environment, and routinely make and promote choices that are for the benefit of the environment. Their influence will be instrumental in achieving subscriptions. High-profile opinion leaders may appear in program communications. Their objective, third-party endorsements would help encourage others to join the program. These organizations and individuals could also benefit from appearing in the communications, with the added awareness of their positive contributions for BC's environment.

Our communications will also reach a secondary audience – residential customers who consider themselves to be environmentally-minded, but who aspire to be more environmentally conscious in their actions and choices. While they are not the most likely to participate at the outset, their awareness of the Terasen Gas Green Gas program could lead to subscribing in the future.

Maintaining Subscriptions

Communications to subscribers[1] will be designed to reinforce the decision to participate and engage subscribers in the program on an ongoing basis by:

- keeping them informed on program developments and renewable energy news,
- maintaining awareness and understanding for the program's environmental benefits, and
- creating a sense of community among participants; they are setting a positive example and making a difference for the province and its future.

Program subscribers will also be encouraged to let others know about the program. Referrals from current subscribers

1.2. Key Messages

Upon approval, customer communications will begin with the launch of the program and continue on an ongoing basis to maintain subscription levels. Messages to be communicated will include but are not limited to the following:

- Biogas is a clean energy source that is captured from decomposing organic material at sites such as landfills, agriculture waste and wastewater treatment facilities, and can be used for heating applications, , electricity generation or as a transportation fuel.

[1] Customers who have opted into the Green Gas Program

- Biogas, which is a readily available and renewable source of energy, is carbon neutral and will be one of the most environmentally-sound fuels available for use in BC homes; a 10 per cent biomethane blend produces 10 per cent fewer GHG emissions.

- Providing British Columbians with renewable alternative energies, like biogas, makes good sense. It is a natural extension of the piped energy services Terasen Gas has delivered for over a century.

- The Terasen Gas Green Gas program is one way Terasen Gas is participating in BC's transition to a sustainable energy future.

- Subscribing to the Terasen Gas Green Gas program is a simple way customers can support the development of this renewable energy source within our province today and contribute to the environment for tomorrow.

1.3. Customer Education Tactics

Mass media is the best channel to create awareness for a new program. It is also the channel to which innovators (those who are first to use a new product or service) best respond, particularly when the message is presented in a logical, informative tone and manner.

The proposed customer education budget for the Green Gas program is conservative and does not permit extensive use of traditional, mass media channels. However, print and online ads will be used to reach customers who are interested in environment-friendly choices and who tend to be among the first to use new products and services.

Bill inserts and bill messages will be used to educate all Terasen Gas residential customers about biogas as a renewable energy source and invite those who qualify for the program (i.e. not currently with a gas marketer) to participate. At least once in a 12-month period this would be an insert dedicated to the Green Gas program. Additionally, the newsletter "Get Comfortable", distributed twice a year, will include an article on the program. Occasionally the message at the bottom of the bill will be used to direct customers to the Terasen Gas website for program details.

Direct mail will be considered to further target Terasen's residential customers who have previously participated in one of our energy efficiency programs. Customers who have taken past action to be energy efficient, thereby reducing their environmental footprint, are likely to be strong candidates for the Green Gas program.

APPENDIX – H

Promotional offers – Time-limited incentives will be used to:

- stimulate program subscriptions within a specified timeframe; and/or
- generate program referrals.

Tactics used may include contests or low-cost, high-value, high-relevance giveaways (e.g. a free download of a book on an environmental topic).

Cross promotions with related third parties will also be used to reach specific target audiences and to leverage the other organization's sphere of influence.

News releases will be issued at the time this proposal is submitted to the B.C. Utilities Commission and upon receiving the decision. Subsequently, further news releases will be issued to communicate the launch of the green gas program and to update the public on milestones during the program.

Consumer shows / community-level events / street team – The Green Gas program will be promoted at fall homeshows in which Terasen Gas is scheduled to participate (e.g. Vancouver, Victoria and/or Kelowna). We will also look into hosting an information booth at fall and winter farmers markets and other community-based events.

We will explore the use of the Terasen Gas street team representatives in a street-level launch event to attract media and public attention in a manner that will have the potential to "go viral" through social media and generate media coverage.

Website – All communication materials will direct people to our website, terasengas.com, for

- general information on green gas as a renewable energy source,
- detailed information on the Terasen Gas Green Gas program; and
- the ability to subscribe to the program online.

Videos are an engaging medium for education purposes. Whether a short 60-second piece or a more detailed two to three-minute one, a video can help people grasp new information more easily. Two videos would be developed; they would both be educational and informative. A longer video would be more logical and explanatory in its tone and manner (attractive to those who need detailed explanations), while a shorter video would be more entertaining and viral in nature. The videos would be delivered on our website, on YouTube, at a homeshow booth and at speaking engagements.

Subscriber communications – we will conduct ongoing communication with program participants for two important reasons:

- to maintain subscriptions in the program by reinforcing the positive benefits of participation; and
- to encourage participants to refer others to the program.

These communications will be electronic, i.e. environmentally-friendly, and will include as an example a quarterly e-mail newsletter.

An employee communications campaign will take place at the launch of the Terasen Gas Green Gas program. It is important that all employees understand the benefits of biogas as a renewable energy source and the details of the green gas program. They are Terasen Gas' best ambassadors to inform customers about this new program. A small-scale launch event will introduce the program to employees, while the company intranet will contain detailed information.

1.4. Customer Education Timeline

Pre-launch **Summer – Fall 2010**

Third-party endorsers will be contacted so that they can be aware of the potential program in advance. Then upon approval of the program, communication materials will be developed featuring their endorsement. With the launch of the program these individuals or organizations can be among the first to subscribe to the Terasen Gas Green Gas program.

Launch **Fall 2010 – Winter 2011**

To garner attention from the media, public, opinion leaders and customers, the program will be launched with all elements of the communication strategy outlined above.

Post-launch **Winter 2011 – Fall 2011**

To maintain participation in the program, subscriber communications will be implemented. Additionally, targeted communications to achieve new subscribers will continue until the program is fully subscribed.

Appendix I

BIOMETHANE SUPPLY CONTRACTS

FILED CONFIDENTIALLY

Appendix J

FINANCIAL SCHEDULES

Terasen Gas Inc. Biogas O&M Details

Line	Particulars	2010 ($ thousands)	2011 ($ thousands)	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			

Terasen Gas Inc. Biogas Capital Details

Line	Particulars	Catalyst	Salmon Arm	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			

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Capital Spending
Schedule 1
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	Capital Spending Prior to 2010											
2	Meter		-									
3	Distribution Measurement & Regulating		-									
4	Distribution Main Extension		-									
5			-									
6			-									
7	Total Capital Spending Prior to 2010	Sum of Lines 2 through 6	-									
8												
9	AFUDC Prior to 2010											
10	Meter		-									
11	Distribution Measurement & Regulating		-									
12	Distribution Main Extension		-									
13			-									
14			-									
15	Total AFUDC Prior to 2010	Sum of Lines 10 through 14	-									
16												
17	Capital Spending 2010 Onwards											
18	Meter		472.8	-	-	-	-	-	-	-	-	-
19	Distribution Measurement & Regulating		524.5	-	-	-	-	-	-	-	-	-
20	Distribution Main Extension		273.0	-	-	-	-	-	-	-	-	-
21			-	-	-	-	-	-	-	-	-	-
22			-	-	-	-	-	-	-	-	-	-
23	Total Capital Spending 2010 Onwards	Sum of Lines 18 through 22	1,270.3	-	-	-	-	-	-	-	-	-
24												
25	AFUDC 2010 Onwards											
26	Meter		1.9	-	-	-	-	-	-	-	-	-
27	Distribution Measurement & Regulating		3.4	-	-	-	-	-	-	-	-	-
28	Distribution Main Extension		2.3	-	-	-	-	-	-	-	-	-
29			-	-	-	-	-	-	-	-	-	-
30			-	-	-	-	-	-	-	-	-	-
31	Total AFUDC 2010 Onwards	Sum of Lines 26 through 30	7.6	-	-	-	-	-	-	-	-	-
32												
33	Total Capital Spending[1]	Line 23	1,270.3	-	-	-	-	-	-	-	-	-
34	Total AFUDC	Line 31	7.6	-	-	-	-	-	-	-	-	-
35	Total Annual Capital Spending and AFUDC	Line 33 + Line 34	1,277.9	-	-	-	-	-	-	-	-	-
36												
37	Contributions in Aid of Construction		-	-	-	-	-	-	-	-	-	-
38	Removal Costs		-	-	-	-	-	-	-	-	-	-
39	Net Annual Project Costs- Capital	Line 35 + 37 + 38	1,277.9	-	-	-	-	-	-	-	-	-
40												
41	Total Project Costs- Capital Spending and AFUDC	Sum of Line 35	**1,277.9**									
42	Total Net Project Costs- Capital Spending, AFUDC, CIAC & Removal Costs	Sum of Line 39	**1,277.9**									
43												
44	1- Excluding capitalized overhead; First year of analysis includes all prior year spending											

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Cost of Gas
Schedule 2
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1												
2	**Total Cost of Biogas ($000's)**		-	-	-	-	-	-	-	-	-	-
3	**TGI Non-Bypass Sales & T-Service Volume (TJ)**		49,895	157,738	157,738	157,738	157,738	157,738	157,738	157,738	157,738	157,738
4												

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: O&M, Other Revenue and Property Tax
Schedule 3
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	**Gross O&M**											
2	Labour Costs		-	-	100.0	102.0	104.0	106.1	108.2	110.4	112.6	114.9
3												
4	Vehicle Costs		-	-	-	-	-	-	-	-	-	-
5	Employee Expenses		-	-	-	-	-	-	-	-	-	-
6	Materials & Supplies		-	-	-	-	-	-	-	-	-	-
7	Computer Costs		-	-	10.0	10.2	10.4	10.6	10.8	11.0	11.3	11.5
8	Fees & Administrations Costs		-	-	306.4	312.5	318.8	325.1	331.6	338.3	345.0	351.9
9	Contractor Costs		-	-	-	-	-	-	-	-	-	-
10	Facilities		-	-	-	-	-	-	-	-	-	-
11	Recoveries & Revenue		-	-	-	-	-	-	-	-	-	-
12												
13	Non-Labour Costs		-	-	316.4	322.7	329.2	335.7	342.5	349.3	356.3	363.4
14												
15	Total Gross O&M Expenses		-	-	416.4	424.7	433.2	441.9	450.7	459.7	468.9	478.3
16												
17	(Less): Capitalized Overhead		-	-	(58.3)	(59.5)	(60.6)	(61.9)	(63.1)	(64.4)	(65.6)	(67.0)
18	Add (Less): Adjustment		-	-	-	-	-	-	-	-	-	-
19	Net O&M		-	-	358.1	365.3	372.6	380.0	387.6	395.4	403.3	411.3
20												
21	**Other Revenue**											
22	Deferred Cost of Service	2010 and 2011; Schedule 10, Lines 5 + 9 + 10	(55.0)	(168.7)	-	-	-	-	-	-	-	-
23			-	-	-	-	-	-	-	-	-	-
24	Total Other Revenue		(55.0)	(168.7)	-	-	-	-	-	-	-	-
25												
26	**Property Taxes**											
27	General, School and Other		-	-	-	-	-	-	-	-	-	-
28	1% in Lieu of General Municipal Tax[1]	Schedule 10, Line 12 x 1%	-	-	-	-	9.4	9.2	9.2	5.6	5.7	5.7
29	Total Property Taxes		-	-	-	-	9.4	9.2	9.2	5.6	5.7	5.7
30												

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Gross Plant in Service & Contributions in Aid of Construction
Schedule 4
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	**Gross Plant in Service**											
2												
3	Gross Plant in Service, Beginning											
4	Meter	Preceeding Year, Line 31	-	474.7	474.7	474.7	474.7	474.7	474.7	474.7	474.7	474.7
5	Distribution Measurement & Regulating	Preceeding Year, Line 32	-	527.9	527.9	527.9	527.9	527.9	527.9	527.9	527.9	527.9
6	Distribution Main Extension	Preceeding Year, Line 33	-	275.3	275.3	275.3	275.3	275.3	275.3	275.3	275.3	275.3
7												
8												
9	Capitalized Overhead	Preceeding Year, Line 36	-	-	-	58.3	117.8	178.4	240.3	303.4	367.7	433.4
10	Total Gross Plant in Service, Beginning	Sum of Lines 4 through 9	-	1,277.9	1,277.9	1,336.2	1,395.7	1,456.3	1,518.2	1,581.3	1,645.7	1,711.3
11												
12	Gross Plant in Service, Additions											
13	Meter	Schedule 1, Lines 2 + 10 + 18 + 26	474.7	-	-	-	-	-	-	-	-	-
14	Distribution Measurement & Regulating	Schedule 1, Lines 3 + 11 + 19 + 27	527.9	-	-	-	-	-	-	-	-	-
15	Distribution Main Extension	Schedule 1, Lines 4 + 12 + 20 + 28	275.3	-	-	-	-	-	-	-	-	-
16												
17												
18	Capitalized Overhead	Schedule 3, - Line 17	-	-	58.3	59.5	60.6	61.9	63.1	64.4	65.6	67.0
19	Total Gross Plant in Service, Additions	Sum of Lines 13 through 18	1,277.9	-	58.3	59.5	60.6	61.9	63.1	64.4	65.6	67.0
20												
21	Gross Plant in Service, Retirements											
22	Meter		-	-	-	-	-	-	-	-	-	-
23	Distribution Measurement & Regulating		-	-	-	-	-	-	-	-	-	-
24	Distribution Main Extension		-	-	-	-	-	-	-	-	-	-
25												
26												
27	Capitalized Overhead		-	-	-	-	-	-	-	-	-	-
28	Total Gross Plant in Service, Retirements	Sum of Lines 22 through 27	-	-	-	-	-	-	-	-	-	-
29												
30	Gross Plant in Service, Ending											
31	Meter	Line 4 + Line 13 + Line 22	474.7	474.7	474.7	474.7	474.7	474.7	474.7	474.7	474.7	474.7
32	Distribution Measurement & Regulating	Line 5 + Line 14 + Line 23	527.9	527.9	527.9	527.9	527.9	527.9	527.9	527.9	527.9	527.9
33	Distribution Main Extension	Line 6 + Line 15 + Line 24	275.3	275.3	275.3	275.3	275.3	275.3	275.3	275.3	275.3	275.3
34												
35												
36	Capitalized Overhead	Line 9 + Line 18 + Line 27	-	-	58.3	117.8	178.4	240.3	303.4	367.7	433.4	500.3
37	Total Gross Plant in Service, Ending	Sum of Lines 31 through 36	1,277.9	1,277.9	1,336.2	1,395.7	1,456.3	1,518.2	1,581.3	1,645.7	1,711.3	1,778.3
38												
39												
40	**Contributions in Aid of Construction (CIAC)**											
41	CIAC, Beginning		-	-	-	-	-	-	-	-	-	-
42	Additions		-	-	-	-	-	-	-	-	-	-
43	Retirements		-	-	-	-	-	-	-	-	-	-
44	CIAC, Ending	Sum of Lines 41 through 43	-	-	-	-	-	-	-	-	-	-
45												

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Accumulated Depreciation & Amortization
Schedule 5
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	**Accumulated Depreciation**											
2												
3	Accumulated Depreciation, Beginning											
4	Meter	Preceeding Year, Line 31	-	(12.7)	(37.9)	(63.1)	(88.3)	(113.5)	(138.7)	(164.0)	(189.2)	(214.4)
5	Distribution Measurement & Regulating	Preceeding Year, Line 32	-	(15.2)	(45.4)	(75.6)	(105.8)	(136.0)	(166.2)	(196.4)	(226.6)	(256.8)
6	Distribution Main Extension	Preceeding Year, Line 33	-	(2.6)	(7.8)	(13.0)	(18.2)	(23.4)	(28.6)	(33.8)	(39.1)	(44.3)
7												
8												
9	Capitalized Overhead	Preceeding Year, Line 36	-	-	-	(0.8)	(3.3)	(7.5)	(13.4)	(21.0)	(30.5)	(41.8)
10	Total Accumulated Depreciation, Beginning	Sum of Lines 4 through 9	-	(30.6)	(91.2)	(152.6)	(215.7)	(280.5)	(347.0)	(415.2)	(485.3)	(557.2)
11												
12	Accumulated Depreciation, Depreciation Expense											
13	Meter@ 5.31%	Schedule 4, Line 4 & Line 13	(12.7)	(25.2)	(25.2)	(25.2)	(25.2)	(25.2)	(25.2)	(25.2)	(25.2)	(25.2)
14	Distribution Measurement & Regulating @ 5.72%	Schedule 4, Line 5 & Line 14	(15.2)	(30.2)	(30.2)	(30.2)	(30.2)	(30.2)	(30.2)	(30.2)	(30.2)	(30.2)
15	Distribution Main Extension@ 1.89%	Schedule 4, Line 6 & Line 15	(2.6)	(5.2)	(5.2)	(5.2)	(5.2)	(5.2)	(5.2)	(5.2)	(5.2)	(5.2)
16												
17												
18	Capitalized Overhead@ 2.82%	Schedule 4, Line 9 & Line 18	-	-	(0.8)	(2.5)	(4.2)	(5.9)	(7.7)	(9.5)	(11.3)	(13.2)
19	Total Accumulated Depreciation, Depreciation Expense	Sum of Lines 13 through 18	(30.6)	(60.6)	(61.4)	(63.1)	(64.8)	(66.5)	(68.3)	(70.1)	(71.9)	(73.8)
20												
21	Accumulated Depreciation, Retirements											
22	Meter	Schedule 4, Line 22	-	-	-	-	-	-	-	-	-	-
23	Distribution Measurement & Regulating	Schedule 4, Line 23	-	-	-	-	-	-	-	-	-	-
24	Distribution Main Extension	Schedule 4, Line 24	-	-	-	-	-	-	-	-	-	-
25												
26												
27	Capitalized Overhead	Schedule 4, Line 27	-	-	-	-	-	-	-	-	-	-
28	Total Accumulated Depreciation, Retirements	Sum of Lines 22 through 27	-	-	-	-	-	-	-	-	-	-
29												
30	Accumulated Depreciation, Ending											
31	Meter	Line 4 + Line 13 + Line 22	(12.7)	(37.9)	(63.1)	(88.3)	(113.5)	(138.7)	(164.0)	(189.2)	(214.4)	(239.6)
32	Distribution Measurement & Regulating	Line 5 + Line 14 + Line 23	(15.2)	(45.4)	(75.6)	(105.8)	(136.0)	(166.2)	(196.4)	(226.6)	(256.8)	(287.0)
33	Distribution Main Extension	Line 6 + Line 15 + Line 24	(2.6)	(7.8)	(13.0)	(18.2)	(23.4)	(28.6)	(33.8)	(39.1)	(44.3)	(49.5)
34												
35												
36	Capitalized Overhead	Line 9 + Line 18 + Line 27	-	-	(0.8)	(3.3)	(7.5)	(13.4)	(21.0)	(30.5)	(41.8)	(55.0)
37	Total Accumulated Depreciation, Ending	Sum of Lines 31 through 36	(30.6)	(91.2)	(152.6)	(215.7)	(280.5)	(347.0)	(415.2)	(485.3)	(557.2)	(631.0)
38												
39												
40	**Accumulated Amortization of Contributions in Aid of Construction (CIAC)**											
41	Accumulated Amortization CIAC, Beginning		-	-	-	-	-	-	-	-	-	-
42	Amortization @ 0%	[1]	-	-	-	-	-	-	-	-	-	-
43	Retirements		-	-	-	-	-	-	-	-	-	-
44	Accumulated Amortization CIAC, Ending	Sum of Lines 41 through 43	-	-	-	-	-	-	-	-	-	-
45												
46	**Removal Cost Provision**											
47	Meter		-	-	-	-	-	-	-	-	-	-
48	Distribution Measurement & Regulating		-	-	-	-	-	-	-	-	-	-
49	Distribution Main Extension		-	-	-	-	-	-	-	-	-	-
50												
51												
52	Total Removal Cost Provision	Sum of Lines 47 through 51	-	-	-	-	-	-	-	-	-	-
53												
54	1- Depreciation & Amortization Expense calculation is based on opening balance + (additions x in-service days/365 if it is the in-service year for project/; otherwise, additions x 1/2)											

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Capital Cost Allowance
Schedule 6
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	**Meter- Class 51 @ 6%**											
2	Opening Balance	Preceeding Year, Line 5	-	459	431	405	381	358	337	316	297	280
3	Additions	Schedule 4 , Line 13 - AFUDC	473	-	-	-	-	-	-	-	-	-
4	CCA	[Line 2 + (Line 3 x 1/2)] x CCA Rate	(14)	(28)	(26)	(24)	(23)	(21)	(20)	(19)	(18)	(17)
5	Closing Balance	Sum of Lines 2 through 4	459	431	405	381	358	337	316	297	280	263
6												
7	**Distribution Measurement & Regulating - Class 51 @ 6%**											
8	Opening Balance	Preceeding Year, Line 11	-	509	478	450	423	397	373	351	330	310
9	Additions	Schedule 4 , Line 14 - AFUDC	524	-	-	-	-	-	-	-	-	-
10	CCA	[Line 8 + (Line 9 x 1/2)] x CCA Rate	(16)	(31)	(29)	(27)	(25)	(24)	(22)	(21)	(20)	(19)
11	Closing Balance	Sum of Lines 8 through 10	509	478	450	423	397	373	351	330	310	292
12												
13	**Distribution Main Extension- Class 51 @ 6%**											
14	Opening Balance	Preceeding Year, Line 17	-	265	249	234	220	207	194	183	172	161
15	Additions	Schedule 4 , Line 15 - AFUDC	273	-	-	-	-	-	-	-	-	-
16	CCA	[Line 14 + (Line 15 x 1/2)] x CCA Rate	(8)	(16)	(15)	(14)	(13)	(12)	(12)	(11)	(10)	(10)
17	Closing Balance	Sum of Lines 14 through 16	265	249	234	220	207	194	183	172	161	152
18												
19	**Capitalized Overhead- Class Average @ 5.27%**											
20	Opening Balance	Preceeding Year, Line 23	-	-	-	32	64	94	124	152	180	207
21	Additions	Schedule 3 , Line 17 x 8 / 14	-	-	33	34	35	35	36	37	38	38
22	CCA	[Line 20 + (Line 21 x 1/2)] x CCA Rate	-	-	(1)	(3)	(4)	(6)	(7)	(9)	(10)	(12)
23	Closing Balance	Sum of Lines 20 through 22	-	-	32	64	94	124	152	180	207	233
24												
25	**Total CCA**											
26	Opening Balance	Preceeding Year, Line 29	-	1,232	1,158	1,121	1,087	1,056	1,028	1,002	979	958
27	Additions	[1]	1,270	-	33	34	35	35	36	37	38	38
28	CCA		(38)	(74)	(70)	(68)	(66)	(64)	(62)	(60)	(58)	(57)
29	Closing Balance	Sum of Lines 26 through 28	1,232	1,158	1,121	1,087	1,056	1,028	1,002	979	958	939
30	1- Schedule 4 , Line 19 - Line 18, + Line 21 above - AFUDC											

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Deferred Charges
Schedule 7
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	*Deferred Charge- O&M*											
2	Opening Balance	Previous Year, Line 8	-	273.6	586.9	391.3	195.6	-	-	-	-	-
3	Gross Additions		358.6	375.1	-	-	-	-	-	-	-	-
4	Tax	Line 3 x Tax Rate	(102.2)	(99.4)	-	-	-	-	-	-	-	-
5	AFUDC	(Lines 2 + 3 + 4) x Schedule 11, Line 17	17.3	37.5	-	-	-	-	-	-	-	-
6	Net Additions	Sum of Lines 3 through 5	273.6	313.3	-	-	-	-	-	-	-	-
7	Amortization Expense @ 3 years		-	-	(195.6)	(195.6)	(195.6)	-	-	-	-	-
8	Closing Balance	Lines 2 + 6 + 7	273.6	586.9	391.3	195.6	-	-	-	-	-	-
9												
10	*Deferred Charge- Cost of Service*											
11	Opening Balance	Previous Year, Line 17	-	55.0	223.8	149.2	74.6					
12	Gross Additions	2010 and 2011; Schedule 10, Lines 5 + 9 + 10	55.0	168.7	-	-	-					
13	Tax											
14	AFUDC		-	-								
15	Net Additions	Sum of Lines 12 through 14	55.0	168.7	-	-	-					
16	Amortization Expense @ 3 years		-	-	(74.6)	(74.6)	(74.6)					
17	Closing Balance	Lines 11 + 15 + 16	55.0	223.8	149.2	74.6	-					
18												
19												
20	**<u>Deferred Charge- Non-Rate Base</u>**											
21	Opening Balance	Previous Year, Line 28	-	328.7	-	-	-	-	-	-	-	-
22	Opening Balance, Adjustment		-	-	-	-	-	-	-	-	-	-
23	Gross Additions	Line 3 + Line 12	413.6	543.8	-	-	-	-	-	-	-	-
24	Tax	Line 4 + Line 13	(102.2)	(99.4)	-	-	-	-	-	-	-	-
25	AFUDC	Line 5 + Line 14	17.3	37.5	-	-	-	-	-	-	-	-
26	Net Additions	Sum of Lines 23 through 25	328.7	482.0	-	-	-	-	-	-	-	-
27	Amortization Expense	Line 7 + Line 16	-	-	-	-	-	-	-	-	-	-
28	Closing Balance	Lines 21 + 26 + 27	328.7	810.7	-	-	-	-	-	-	-	-
29												
30	**<u>Deferred Charge- Rate Base</u>**											
31	Opening Balance	Previous Year, Line 38	-	-	810.7	540.4	270.2	-	-	-	-	-
32	Opening Balance, Adjustment		-	-	-	-	-	-	-	-	-	-
33	Gross Additions	Line 3 + Line 12	-	-	-	-	-	-	-	-	-	-
34	Tax	Line 4 + Line 13	-	-	-	-	-	-	-	-	-	-
35	Net Additions	Line 33 + Line 34	-	-	-	-	-	-	-	-	-	-
36	Amortization Expense	Line 7 + Line 16	-	-	(270.2)	(270.2)	(270.2)	-	-	-	-	-
37	Closing Balance	Lines 31 + 35 + 36	-	-	540.4	270.2	-	-	-	-	-	-
38												
39	Deferred Charge, Mid-Year	(Line 31+ Line 32 + Line 37) / 2	-	-	675.5	405.3	135.1	-	-	-	-	-

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Rate Base
Schedule 8
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	**Rate Base**											
2	Gross Plant In Service- Beginning	Schedule 4, Line 10	-	1,277.9	1,277.9	1,336.2	1,395.7	1,456.3	1,518.2	1,581.3	1,645.7	1,711.3
3	Gross Plant In Service- Ending	Schedule 4, Line 37	1,277.9	1,277.9	1,336.2	1,395.7	1,456.3	1,518.2	1,581.3	1,645.7	1,711.3	1,778.3
4												
5	Accumulated Depreciation- Beginning	Schedule 5, Line 10	-	(30.6)	(91.2)	(152.6)	(215.7)	(280.5)	(347.0)	(415.2)	(485.3)	(557.2)
6	Accumulated Depreciation- Ending	Schedule 5, Line 37	(30.6)	(91.2)	(152.6)	(215.7)	(280.5)	(347.0)	(415.2)	(485.3)	(557.2)	(631.0)
7												
8	Contributions in Aid of Construction- Beginning	Schedule 4, Line 41	-	-	-	-	-	-	-	-	-	-
9	Contributions in Aid of Construction- Ending	Schedule 4, Line 44	-	-	-	-	-	-	-	-	-	-
10												
11	Accumulated Amortization- Beginning	Schedule 5, Line 41	-	-	-	-	-	-	-	-	-	-
12	Accumulated Amortization- Ending	Schedule 5, Line 44	-	-	-	-	-	-	-	-	-	-
13												
14	Net Plant in Service, Mid-Year	Sum (Lines 2 through 12)/2	623.7	1,217.1	1,185.2	1,181.8	1,178.0	1,173.6	1,168.7	1,163.2	1,157.2	1,150.7
15												
16	Adjustment to 13-month average		(329.1)	-	-	-	-	-	-	-	-	-
17	Unamortized Deferred Charges, Mid-Year	Schedule 7, Line 39	-	-	675.5	405.3	135.1	-	-	-	-	-
18	Cash Working Capital	[1]	(2.6)	(2.6)	(2.7)	(2.8)	(2.9)	(3.0)	(3.2)	(3.3)	(3.4)	(3.6)
19	**Total Rate Base**	**Sum of Lines 14 through 18**	**292.0**	**1,214.5**	**1,858.1**	**1,584.4**	**1,310.2**	**1,170.5**	**1,165.5**	**1,159.9**	**1,153.8**	**1,147.1**
20												
21	**Return on Rate Base**											
22	Equity Return	Line 19 x ROE x Equity %	11.1	46.2	70.6	60.2	49.8	44.5	44.3	44.1	43.8	43.6
23	Debt Component	Line 19 x (LTD Rate x LTD% + STD Rate x STD %)	12.0	50.1	76.7	65.4	54.1	48.3	48.1	47.9	47.6	47.3
24	Total Earned Return	Line 22 + Line 23	**23.1**	**96.3**	**147.3**	**125.6**	**103.9**	**92.8**	**92.4**	**91.9**	**91.5**	**90.9**
25	Return on Rate Base %	Line 24 / Line 19	7.90%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%
26												
27												
28	1- Schedule 4, Line 37 x TGI CWC/Closing GPIS %											

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Income Tax Expense
Schedule 9
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	**Income Tax Expense**											
2												
3	Earned Return	Schedule 8, Line 24	23.1	96.3	147.3	125.6	103.9	92.8	92.4	91.9	91.5	90.9
4	Deduct: Interest on debt	Schedule 8, Line 23	(12.0)	(50.1)	(76.7)	(65.4)	(54.1)	(48.3)	(48.1)	(47.9)	(47.6)	(47.3)
5	Add (Deduct): Amortization Expense	Schedule 7, Line 36	-	-	270.2	270.2	270.2	-	-	-	-	-
6	Add: Depreciation Expense	Schedule 5, Line 19 + Line 42	30.6	60.6	61.4	63.1	64.8	66.5	68.3	70.1	71.9	73.8
7	Add: Removal Cost Provision	Schedule 5, Line 52	-	-	-	-	-	-	-	-	-	-
8	Deduct: Overhead Capitalized Expensed for Tax Purposes	Schedule 3 , Line 17 x 6 / 14	-	-	(25.0)	(25.5)	(26.0)	(26.5)	(27.0)	(27.6)	(28.1)	(28.7)
9	Deduct: Capital Cost Allowance	Schedule 6, Line 28	(38.1)	(73.9)	(70.4)	(67.9)	(65.7)	(63.6)	(61.7)	(60.0)	(58.4)	(57.0)
10	Taxable Income After Tax	Sum of Lines 3 through 9	3.5	32.8	306.9	300.1	293.1	20.9	23.8	26.6	29.2	31.7
11												
12	Income Tax Rate		28.50%	26.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
13	1 - Current Income Tax Rate	1 - Line 12	71.50%	73.50%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%
14												
15	Taxable Income	Line 10 / Line 13	4.9	44.7	409.2	400.1	390.8	27.8	31.7	35.4	38.9	42.2
16												
17	Total Income Tax Expense	Line 15 x Line 12	1.4	11.8	102.3	100.0	97.7	7.0	7.9	8.9	9.7	10.6
18	Adjustments		-	-	-	-	-	-	-	-	-	-
19	Net Tax Expense	Line 17 + Line 18	1.4	11.8	102.3	100.0	97.7	7.0	7.9	8.9	9.7	10.6
20												

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Revenue Requirement
Schedule 10
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	**Revenue Requirement**											
2	Cost of Energy Sold	Schedule 2, Line 2	-	-	-	-	-	-	-	-	-	-
3	Operation and Maintenance	Schedule 3, Line 19	-	-	358.1	365.3	372.6	380.0	387.6	395.4	403.3	411.3
4	Property Taxes	Schedule 3, Line 29	-	-	-	-	9.4	9.2	9.2	5.6	5.7	5.7
5	Depreciation Expense	Schedule 5, Line 19 + Line 42	30.6	60.6	61.4	63.1	64.8	66.5	68.3	70.1	71.9	73.8
6	Removal Cost Provision	Schedule 5, Line 52	-	-	-	-	-	-	-	-	-	-
7	Amortization Expense	Schedule 7, Line 36	-	-	270.2	270.2	270.2	-	-	-	-	-
8	Other Revenue	Schedule 3, Line 24	(55.0)	(168.7)	-	-	-	-	-	-	-	-
9	Income Taxes	Schedule 9, Line 19	1.4	11.8	102.3	100.0	97.7	7.0	7.9	8.9	9.7	10.6
10	Earned Return	Schedule 8, Line 24	23.1	96.3	147.3	125.6	103.9	92.8	92.4	91.9	91.5	90.9
11												
12	**Annual Revenue Requirement**	Sum of Lines 2 through 10	**-**	**-**	**939.3**	**924.2**	**918.5**	**555.5**	**565.4**	**571.8**	**582.0**	**592.3**
13												
14	**Impact as a % of Existing Terasen Gas Inc. Residential Customer Delivery Margin**		**0.00%**	**0.00%**	**0.17%**	**0.17%**	**0.17%**	**0.10%**	**0.10%**	**0.11%**	**0.11%**	**0.11%**
15												
16	Existing Residential Delivery Rate ($/GJ)		3.179	3.275	3.275	3.275	3.275	3.275	3.275	3.275	3.275	3.275
17	Existing Residential Basic Charge ($/Month)		11.84	11.84	11.84	11.84	11.84	11.84	11.84	11.84	11.84	11.84
18												
19	Approximate Annual Residential Customer Volume (TJ)		49,895	157,738	157,738	157,738	157,738	157,738	157,738	157,738	157,738	157,738
20	Approximate Residential Delivery Rate Rider for Biogas Program ($/GJ)		-	-	0.006	0.006	0.006	0.004	0.004	0.004	0.004	0.004
21												
22	Approximate Residential Annual Use for Annual Bill Purposes (GJ/Year)		95									
23	Approximate Existing Delivery Charge Residential Annual Bill ($/Year)		444.09	453.21	453.21	453.21	453.21	453.21	453.21	453.21	453.21	453.21
24	Approximate Delivery Charge Residential Annual Bill ($/Year)		444.09	453.21	453.77	453.76	453.76	453.54	453.55	453.55	453.56	453.56
25	Approximate Residential Annual Bill Impact ($/Year)		-	-	0.57	0.56	0.55	0.33	0.34	0.34	0.35	0.36

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Levelized Rate Calculation
Schedule 11
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1												
2	Annual Revenue Requirement ($000s)	Schedule 10, Line 12	-	-	939.3	924.2	918.5	555.5	565.4	571.8	582.0	592.3
3	Annual Number of Customers		840,427	843,999	843,999	843,999	843,999	843,999	843,999	843,999	843,999	843,999
4												
5	**Annual Discount Rate**											
6	Equity Component											
7	ROE %		9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
8	Equity Portion		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
9	Debt Component											
10	Long Term Debt Rate		6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%
11	Long Term Debt Portion		58.55%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%
12	Short Term Debt Rate		2.25%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
13	Short Term Debt Portion		1.45%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%
14												
15	Tax Rate		28.50%	26.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
16												
17	After- Tax Weighted Average Cost of Capital (WACC)[1]		6.73%	6.83%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
18												
19	**Present Value of Revenue Requirement**											
20	PV of Annual Revenue Requirement	Line 2 / (1 + Line 17)^Yr	-	-	822.1	756.6	703.5	398.0	379.0	358.5	341.4	325.0
21	Total PV of Revenue Requirement	Sum of Line 20	4,084.1									
22	Total PV of Revenue Requirement, $000s/Yr	Line 21 / Yrs	408.4									
23												
24	PV of Annual Customers	Line 3 / (1 + Line 17)^Yr	840,427	790,014	738,625	690,980	646,408	604,711	565,703	529,212	495,075	463,140
25	Levelized Customers	Sum of Line 24	6,364,295									
26												
27	**Tariff Analysis**											
28	Annual Volume (TJ)	Schedule 2, Line 3	49,895	157,738	157,738	157,738	157,738	157,738	157,738	157,738	157,738	157,738
29												
30	Annual Charge per Customer ($/Yr)	Line 2 x 1000 / Line 3	-	-	1.11	1.10	1.09	0.66	0.67	0.68	0.69	0.70
31	Monthly Charge per Customer ($/Mnth)	Line 30 / 12	-	-	0.09	0.09	0.09	0.05	0.06	0.06	0.06	0.06
32	Annual Volumetric Rate $/GJ	Line 2 / Line 28	-	-	0.006	0.006	0.006	0.004	0.004	0.004	0.004	0.004
33	15 Month Rate $/GJ			-								
34												
35	**Levelized Tariff Analysis**											
36	PV of Annual Volume (TJ)	Line 28 / (1 + Line 17)^Yr	49,895	147,649	138,045	129,140	120,810	113,017	105,727	98,907	92,527	86,558
37	Total PV of Volume (TJ)	Sum of Line 36	1,082,272									
38												
39	Levelized Annual Charge per Customer ($/Yr)	Line 21 x 1000 / Line 25	**0.64**									
40	Levelized Monthly Charge per Customer ($/Mnth)	Line 39 / 12	**0.05**									
41	Levelized Volumetric Rate ($/GJ)	Line 21 / Line 37	**0.004**									
42	1- AFUDC Rate: Line 7 x Line 8 + [(Line 10 x Line 11 + Line 12 x Line 13) x 1- Line 15]											

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Discounted Cash Flow Analysis
Schedule 12
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	**Cash Flow**											
2	Add: Delivery Charge Revenue	Schedule 10, Line 12 - Line 2	-	-	939.3	924.2	918.5	555.5	565.4	571.8	582.0	592.3
3	Less: O&M & Property Tax Expense	Schedule 3, - (Line 15 + Line 29)	-	-	(416.4)	(424.7)	(442.6)	(451.1)	(459.9)	(465.3)	(474.6)	(484.0)
4	EBITDA[1]	Line 2 + Line 3	-	-	522.9	499.5	475.9	104.4	105.5	106.5	107.4	108.3
5	Capital Expenditures[2]	Schedule 1, Line 39	(1,270.3)	-	-	-	-	-	-	-	-	-
6	Deferred Charges	Schedule 7, Lines 23, 24, 33& 34	(311.4)	(444.4)	-	-	-	-	-	-	-	-
7	Terminal Value[3]		822.9	-	-	-	-	-	-	-	-	-
8	Pre-Tax Cash Flow	Sum of Lines 4 through 7	(758.8)	(444.4)	522.9	499.5	475.9	104.4	105.5	106.5	107.4	108.3
9	Tax Expense	Schedule 9, - Line 19	(1.4)	(11.8)	(102.3)	(100.0)	(97.7)	(7.0)	(7.9)	(8.9)	(9.7)	(10.6)
10	Free Cash Flow	Line 8 + Line 9	(760.2)	(456.3)	420.6	399.4	378.2	97.4	97.6	97.7	97.7	97.7
11												
12	WACC %	Schedule 11, Line 17	6.73%	6.83%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
13	Present Value of Free Cash Flow	Line 10 / (1 + Line 12)^Yr	(760.2)	(427.1)	368.1	327.0	289.7	69.8	65.4	61.2	57.3	53.6
14	Total Present Value of Free Cash Flow	Sum of Line 13	**104.9**									
15												
16	1- Earnings Before Interest, Taxes, Depreciation & Amortization (EBITDA)											
17	2- Net of CIAC and removal costs (if applicable) and excludes capitalized overhead											
18	3- 2019: [Schedule 6, ((Lines 5 + 11 + 17) x CCA Rate x Tax Rate) / (CCA Rate + Line 12) / (1 + Line 12)^Yr]+ Line 10 / (Line 12)/ (1 + Line 12)^Yr											

Appendix J-3

FINANCIAL SCHEDULES – GREEN GAS RATE

FILED CONFIDENTIALLY

Appendix K

KNOWLEDGE TECH CONSULTING INFORMATION

KnowledgeTech
consulting inc.

Suite 505
1168 Hamilton St
Vancouver, British Columbia
Canada V6B 2S2

Phone 604.484.4598
Fax 604.648-8480
aytsma@knowledgetech.com
www.knowledgetech.com

KnowledgeTech Consulting
Corporate Overview

Established and incorporated in British Columbia in 1993, KnowledgeTech ("KTC") is a leading Western Canadian based management and information technology consulting services firm headquartered in Vancouver. KTC responds to the needs of corporations and institutions throughout North America, addressing a wide range of management and information technology challenges. KTC has established a solid reputation for providing high value, high quality services, and has built an impressive list of client references.

KTC's goal is to be a key contributor to our client's success. We accomplish this by:

- Developing deep domain expertise relevant to our customer's industry;
- Creating integrated business solutions to achieve real business benefits;
- Empowering our clients to use technology to their competitive advantage;
- Researching industry best practices for the formulation and delivery of our solutions;
- Providing for the transfer of knowledge to our clients, including both business and technology expertise.

KTC's client vertical focus is Energy/Utilities, Healthcare, and Financial Services; however we also have customers in the Retail, Transportation and Not-for-Profit sectors.

Energy/Utilities Industry Expertise

KTC has extensive expertise and experience in the energy sector. We are able to provide subject matter and information technology experts in a number of key energy industry verticals.
The following table highlights our business application area expertise:

Energy Industry Verticals	Business Applications	
• Energy Services • Government • Oil and Gas • Utilities	• AMR • Asset/Maintenance Management • Call Center/Customer Relationship Management • Customer Information and Billing • Electronic Trading • Energy Accounting • Environment • ERP (Financials, HR) • Forecasting (Supply, Demand, Revenue)	• Gas Control • Gas Management • Gas Scheduling • GHG Emissions • Integrity Management • Logistics • Marketing • Measurement Technical Services • Measurement Operations • Production Accounting • Rates and Regulatory • Sales

KTC's energy industry management consulting expertise covers the following areas:

Strategy
We have experience with project portfolio management, facilities planning and corporate strategic direction, including the ability to plans for a portfolio of assets (combination of facilities and contracting assets) such as facility expansions, contracting assets, etc. to meet corporate objectives.

Operations
We have significant depth of operating and maintenance management experience in operations of up-stream, mid-stream and down-stream oil and gas facilities. This includes maintenance planning; turnaround and unit shutdown planning, and planning supervision.

Regulatory
We bring an extensive body of knowledge of both the Provincial and Federal regulatory environments. Our people are experienced and skilled at green field and expansion projects under the provincial and federal (NEB) regulatory environments. We have the ability to provide stakeholder and public consultation, and file regulatory applications, seek regulatory approval in support of our customers.

Royalties
Our team has an in depth knowledge of the royalty methods and calculations in both British Columbia and Alberta. We understand how royalty regimes affect the economics of projects.

Midstream
From development to construction through to operations in the areas of gathering, plants and pipelines our team has accumulated hundreds of years of experience. We are very familiar with all midstream issues, and can provide solutions.

Environmental
We can provide expertise on green-house gas emissions reporting requirements and carbon credit management.

Engineering
We provide engineering in two areas: New Facility and Operational Technical Services. New facility engineering takes you from concept to detail engineering specifications. We then complete the role of contractor's representative throughout the Engineering Procurement and Construction process. Operational Technical Services includes maintenance engineering, operations assessments, and operations and maintenance minor capital upgrades.

Financial Analysis
All projects or strategies have a financial component to them. We can provide financial analysis and expertise as required for all of our assignments

KnowledgeTech consulting inc.

Suite 505
1168 Hamilton Street
Vancouver, B.C. V6B 2S2
Canada

Phone: 604.484.4598
Email: aytsma@knowledgetech.com
Website: www.knowledgetech.com

January 20, 2010

Ms. Janet Devaney
Business Development Manager, Marketing
Terasen Gas Inc.
16705 Fraser Highway
Surrey, BC, V4N 0E8

Dear Janet:

The following is our understanding of the assignment for Janice Feanny of KnowledgeTech on the Terasen Gas BioGas initiative.

Statement of Work

Janice will work on the BioGas project, as part of the BCUC Application Team, in the role of System Impact Analyst.

She will be responsible for documenting the changes to business processes, system impacts and working with IT resources to determine cost estimates for any system impacts.

The timeframe for this work is from January 4, 2010 to March 31, 2010. The objective within this timeframe will be for her to finalize the cost estimates by the end of February. As such, it is likely that she will contribute more time in the January/February timeframe, with less time required in March for additional advice, clarification of costs and any revisions that may be necessary.

The estimated effort over the above timeframe is approximately 2 to 3 days per week or a total of 24 to 30 days.

Objectives

The primary objective of Janice's assignment is to complete a statement of business process and system impacts and required changes that would result from the implementation of the BioGas initiative. This statement will also include cost estimates for the system changes.

Arrangements for Our Services

Our engagement for this assignment will be on a time and materials basis. Our hourly rate for Janice is $125 per hour.

We will only bill for hours worked, and we will submit our invoices monthly. Our payment terms are net 30 days. Applicable taxes will be added to our invoice to the extent required by law. Our fees include general administration, normal correspondence, local travel and incidental expenses. Out of town (outside of the lower mainland beyond Langley) travel expenses will be disbursed at cost. No out of town travel expense will be incurred without prior approval by Terasen management.

Al Ytsma will be the KnowledgeTech Partner responsible for this project, handling the business relationship side of this engagement with Terasen and overall management of our resources.

Janet, I hope that the above information clearly and accurately reflects what Terasen wishes to accomplish for this assignment. Please call me at 604.484.4598 or on my cell at 604.328.1375, or drop me a note at aytsma@knowledgetech.com, if you have any questions.

Lastly, thank you very much for your interest in KnowledgeTech and providing us with the opportunity to assist you on this project.

Yours very truly,

Al Ytsma
Director, Consulting Services

Appendix L
LETTERS OF SUPPORT

CENTRAL HEAT DISTRIBUTION LIMITED
VANCOUVER DISTRICT ENERGY UTILITY
Suite 1, 720 Beatty Street, Vancouver, BC V6B 2M1
Tel 604-688-9584 Fax 604-688-2213 E-mail chdl@telus.net

May 10, 2010

Terasen Gas Inc.,
16705 Fraser Highway,
SURREY, B.C.
V4N 0E8

Attention: Mr. David Bennett,
Director, Resource Planning and Market Development

Dear Mr. Bennett:

Re: Letter of Intent - Biomethane Purchase

This letter is to confirm that Central Heat wishes to purchase 10,000 GJ per year of biomethane from Terasen Gas if approved by the BC Utilities Commission and is willing to sign the appropriate Service Agreement to do so at the anticipated cost of biomethane of $10-$12 per GJ.

We support Terasen Gas in its effort to provide alternative energy solutions, such as biomethane, and we want to play a part in helping this source of renewable energy become more widely available.

Methane gas, otherwise released to atmosphere, has over twenty times the heat retention property of carbon dioxide, thus greenhouse gases are reduced significantly when it is blended with natural gas.

We see this project as the first of many towards building a diverse clean energy sector for British Columbia. Congratulations to Terasen Gas for showing the leadership in make this opportunity a reality.

We look forward to working with Terasen Gas to make this project a success.

Yours truly,

CENTRAL HEAT DISTRIBUTION LIMITED

John S. Barnes,
President and General Manager

JSB/ye

cc: Ms. Janet Devaney, Terasen Gas Inc.

BC AGRICULTURAL RESEARCH & DEVELOPMENT CORPORATION
ardcorp

Renewable Agri-energy Initiative (RAI),
Wednesday, Aril 21st 2010

Subject: Terasen Gas' application to the B.C. Utilities Commission (BCUC) to charge a voluntary premium price for biomethane.

This letter is to show the Renewable Agri-energy Initiative's (RAI) conditional support for Terasen Gas' application to the B.C. Utilities Commission (BCUC) to charge a voluntary premium price for biomethane.

The Renewable Agri-energy Initiative (RAI) was created to heighten awareness of renewable agri-energy and create an enabling environment for renewable agri-energy production to the benefit of B.C.'s agricultural sector. A renewable agri-energy technology identified by the RAI that will benefit both B.C.'s agricultural sector and the province of B.C. as a whole is anaerobic digestion.

Currently, however, the adoption of anaerobic digestion technology is largely economically unfeasible in B.C. due to the Province's electricity and natural gas prices. The RAI is therefore supportive of Terasen Gas' application to the B.C. Utilities Commission (BCUC) to charge a voluntary premium price for biomethane from anaerobic digestion, as it feels this premium will enable anaerobic digestion to become economically feasible in B.C.

The RAI's support for Terasen Gas' application is conditional on the fact that this voluntary premium price will allow for Terasen Gas' rate of return and enable anaerobic digestion owners to receive a fair and reasonable return on investment. Furthermore, this letter of support is for Terasen Gas' application to the BCUC to charge a voluntary premium price for biomethane. As such, this letter is in no way support for any individual anaerobic digestion projects.

By agreeing to Terasen Gas' application, the BCUC will be demonstrating vital leadership in enabling B.C.'s agricultural sector to adopt a technology that will benefit both B.C.'s agricultural sector and the province of B.C. as a whole.

Sincerely,

Mathew Dickson,
(Program Manager, Renewable Agri-energy Initiative).

#230 – 32160 South Fraser Way, Abbotsford, BC V2T 1W5
Phone 604.854.4483 Fax 604.854.4485
Toll Free 1.866.522.3447

BC Bioenergy Network
PARTNERING FOR A GREENER FUTURE

1501-700 West Pender Street
Pender Place I Business Building
Vancouver, BC Canada, V6C 1G8

April 19, 2010

Terasen Gas Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Re: Support for Terasen Gas Renewable Biogas BCUC Application Filing

We are writing this letter to express full support for the Terasen Gas Inc. ("Terasen") filing to the British Columbia Utilities Commission ("BCUC") to bring renewable gas to residential gas customers in British Columbia.

About the BC Bioenergy Network

The BC Bioenergy Network ("BCBN") is a not for profit organization established in 2008 with $25 million from the BC government with the objective to grow a world-class bioenergy industry in BC. We are governed independently by a board of directors, who represent three industry associations (the Council of Forest Industries, the BC Agricultural Council and the BC Technology Industry Association), the University of British Columbia, and the Government of British Columbia (the Deputy Minister of the BC Ministry of Energy, Mines, and Petroleum Resources).

Our mandate is to:

- Maximize the value of BC's biomass resources;
- Develop mission-driven research, development and demonstration projects;
- Reduce GHG emissions;
- Network and partner in BC, Canada, and internationally to advance BC's bioenergy sector; and
- Lever funding to support BC focused bioenergy technology and applications.

Relationship with Terasen Gas

BC Bioenergy Network has been working actively with Terasen on renewable energy for over a year. On September 2009, BC Bioenergy Network signed a Memorandum of Understanding ("MOU") with Terasen to formalize efforts to work collaboratively on areas of mutual interest related to bioenergy development, including exchange of information, outreach and communications activities, and project development.

Biogas Benefits for British Columbians

Providing British Columbians with renewable alternative energies, like biogas, is part of the BC government's objectives and has been outlined in the BC Energy Plan, BC Bioenergy Strategy, and most recently in the March 2010 budget announcements. Renewable biogas can be obtained from municipal landfills, municipal wastewater or agricultural residues which are readily available here in BC, processed and upgraded to pipeline quality, and then injected into the natural gas distribution system. Biogas offers substantial benefits given it is carbon neutral, clean, renewable, and offers more price stability than natural gas. It utilizes wastes and turns them into a source of energy.

In 2008 the "*Feasibility Study – Biogas upgrading and grid injection in the Fraser Valley, British Columbia*", was completed for the BC Innovation Council, which indicated that "anaerobic digestion and biogas upgrading are common and mature technologies used extensively throughout Europe and the USA. In Canada, biogas production is starting to increase. This growth is primarily in Ontario due to favourable renewable energy feed-in tariff regime.

The study further notes that "results from a previous study in 2007, show that organic wastes generated in the lower mainland have the potential to produce and displace the equivalent of over 120 million cubic meter of natural gas per year, i.e. approximately 3.5% of the current lower mainland fossil natural gas consumption. This is equivalent to diesel consumed by 80,000 cars (100 million litres). Biomethane, gas from organic sources, can also be used to fuel compressed natural gas ("CNG") vehicles. Automotive application of biomethane has the potential to displace over 100 million litres of diesel and reduce greenhouse gas ("GHG") emissions by 335,000 tonnes per year. One of the additional advantages of producing biogas from methane sourced from either municipal landfills, wastewater or on-farm waste, is that it can deliver renewable natural gas at a price that can closely compete with fossil fuel when the carbon tax exemption ($1.50/GJ in 2012) and avoided pipeline transportation cost that natural gas from Alberta and northern BC incur are included."

BC Bioenergy Network Supports Terasen's First Investment in Municipal Biogas with a $200,000 Grant

The Columbia Shuswap Regional District ("CSRD") and Terasen are developing a landfill gas ("LFG") collection and upgrade system at the Salmon Arm Landfill. On March 31, 2010, the Board of BC Bioenergy Network approved a grant of $200,000, subject to contracting, to Terasen to be used toward the capital investment in the upgrading portion of the project, estimated at $1.35 million.

The proposed project will be the first in British Columbia to recover raw biogas from a landfill, upgrade the gas to pipeline quality for inclusion in the natural gas distribution infrastructure and potentially to use it as green transportation fuel. This will demonstrate a viable alternative to producing electricity from gas and is a key building block in Terasen's green gas offering to residential customers. This is an excellent fit with BC Bioenergy Network's mandate and provides leverage of its funds. Terasen has further agreed to designate the project as a BC Bioenergy Network Collaborative Demonstration and Development centre, furthering the dissemination of economic and environmental information to regional governments in BC, and assisting them to meet their BC Climate Action Accord goals. This centre is modeled after the successful Collaborative Demonstration and Development centre undertaken with the Regional District of Nanaimo and Cedar Road LFG Inc. on Vancouver Island in conjunction with the BC Bioenergy Network, where the landfill gas if being collected and then utilized to produce electricity.

Project benefits for the province include reduction of GHG emissions through the utilization of landfill gas and an offset associated with the displacement of traditional natural gas by natural gas consumers. BC Bioenergy Network is keen to see the installation of a biomethane compressed gas fuelling station to further generate GHG reductions to displace the utilization of fossil diesel fuels.

The Government of British Columbia has actively promoted its' commitment to supporting the development of clean technology companies while at the same time reducing greenhouse gases in the province. Terasen is demonstrating how a utility can show leadership in supporting government commitments by offering smart, efficient energy choices for its customers, creating local clean energy jobs from the sourcing and delivery of biogas, spurring investment in BC's clean energy sector, and demonstrating the viability of biogas as an energy source, including its potential use in the transportation sector as a clean renewable fuel alternative.

In conclusion, BC Bioenergy Network fully supports Terasen's application for both the green gas offering and the and the first two projects, Catalyst Power and Columbia Shuswap Regional District landfill and trusts that BCUC will also support this environmentally and economically beneficial approach to effective energy planning.

Yours sincerely,

Michael Weedon
Executive Director

BC Sustainable Energy Association

5 - 4217 Glanford Avenue
Victoria, BC Canada V8Z 4B9
(250) 744-2720
info@bcsea.org

5 April 2010

Ms. Erica Hamilton
Secretary, BC Utilities Commission
Vancouver, BC

Dear Ms. Hamilton,

Re: Terasen Gas proposal to bring renewable biogas to residential customers

The BC Sustainable Energy Association is pleased to support the application it understands Terasen Gas will make to the Commission to bring renewable biogas to its residential customers.

Appropriately 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 such, it would contribute to meeting BC's legislated greenhouse gas reduction goals, and it would contribute to reducing BC's contribution to global climate change.

As well, it could increase the awareness among Terasen's customers of climate change and actions that may be taken to address it. This could lead to the beneficial effect of greater public engagement in reducing GHG emissions.

Sincerely,

Thomas Hackney, Vice-President for Policy bullfrogpower™

April 28, 2010

British Columbia Utilities Commission
Box 250, 900 Howe Street, Sixth Floor
Vancouver, B.C. V6Z 2N3

Dear Sir/Madam:

Re: Terasen Gas initiative to offer renewable biogas to residential gas customers in B.C.

It has been brought to our attention that Terasen Gas is seeking support to provide B.C. residential gas customers with the option of purchasing a 10% biogas blend at a premium price to natural gas.

Bullfrog Power supports this initiative to provide customers the choice of purchasing renewable energy options. Bullfrog Power was founded five years ago with the objective of providing a renewable electricity choice to Canadians interested in leading the change to renewable power. Currently, Bullfrog Power offers a renewable electricity choice in six provinces, as well as a solar hot water offering in Ontario. Our experience has been that a growing number of Canadians want clean energy choices, and are prepared to voluntarily pay a premium for 100% clean electricity. We believe that BC gas consumers would similarly welcome a renewable biogas choice. In order to make the biogas offering a success, it must be accompanied by comprehensive communication programs to educate consumers about renewable biogas and its environmental benefits, as Bullfrog has done for our renewable electricity and solar hot water offerings.

Bullfrog Power is supportive of the Terasen Gas biogas initiative and, if called upon, would be willing to participate with Terasen Gas in the successful deployment of renewable biogas market deployment, leveraging our unique expertise in renewable energy market development.

Yours truly,

Tom Heintzman
President

TH:lp

www.bullfrogpower.com

Bullfrog Power Inc. 119 Spadina Avenue, Suite 1000, Toronto, ON M5V 2L1 Canada tel 416.360.3464 fax 416.360.8385

ABBOTSFORD

Abbotsford Spirit of BC

Mayor
George W. Peary

Councillors
Les Barkman
Simon Gibson
Moe Gill
Lynne Harris
Dave F. Loewen
Bill MacGregor
Patricia Ross
John G. Smith

April 12, 2010
File: 5280-01

British Columbia Utilities Commission
Box 250, 900 Howe Street
Sixth Floor
Vancouver BC
V6Z 2N3

c/o

David Bennett, Director, Resource Planning & Market Development
Tersaen Gas Inc.
16705 Fraser Highway
Surrey, BC
V4N 0E8

Dears Sirs:

Re: Support of Terasen Biogas Initiative

The City of Abbotsford wishes to extend its endorsement for the Terasen Gas initiative to supply residential customers with renewable biogas. This proposal is laudable in that it addresses several key issues of concern in the City of Abbotsford.

Abbotsford is one of the most productive agricultural areas in all of Canada, and as such, agriculture provides the economic foundation upon which the community is most dependent. The high concentration of dairy and poultry operations in Abbotsford brings with it the problematic issue of agricultural waste disposal. The introduction of anaerobic digestion (biogas) technology is viewed as a proactive step to address this matter as well as a means of strengthening sustainable farming practises. This proposal will also serve to reduce the negative impacts to the environment associated with agricultural waste and at the same time add a component to farm diversification.

The production of biogas is also a source of clean renewable energy. Abbotsford is pleased to be the first community in British Columbia to have an anaerobic digester and is supportive of initiatives that develop energy alternatives. The benefits of such a facility include the reduction of greenhouse gas emissions and assisting the City in meeting its obligations under Bill 27.

The City of Abbotsford is pleased to support Terasen Gas in its pursuit to deliver biogas through its existing infrastructure as it will help serve to address the issues of agricultural waste disposal and aid the City in its efforts to combat climate change.

Yours truly,

George W. Peary
Mayor

c. Council Members
Frank Pizzuto, City Manager
Jay Teichroeb, General Manager of Economic Development & Planning Services

ELECTORAL AREAS
A- GOLDEN-COLUMBIA
B- REVELSTOKE-COLUMBIA
C- SOUTH SHUSWAP
D- FALKLAND-SALMON VALLEY
E- SICAMOUS-MALAKWA
F- NORTH SHUSWAP-SEYMOUR ARM

MUNICIPALITIES
GOLDEN SALMON ARM
REVELSTOKE SICAMOUS

CSRD

781 MARINE PARK DRIVE NE
BOX 978 SALMON ARM BC
VIE 4P1
TEL: (250) 832-8194
FAX: (250) 832-3375
TOLL FREE: 1-888-248-2773
WEBSITE: www.csrd.bc.ca

2009 01 20 FILE:5360 36 01

Scott Gramm, Business Development Manager
Terason Gas Inc.
16705 Fraser Highway
SURREY, BC, V4N 0E8

RE: Letter of Endorsement –Biogas Upgrading Project

The Columbia Shuswap Regional District (CSRD) is pleased to provide this letter of endorsement to Terasen Gas Inc. (Terasen) to support its application to the British Columbia Utilities Commission (BCUC) for the development of biogas upgrading projects in British Columbia.

The CSRD is committed to becoming a leader in environmental stewardship and sustainability in working with all stakeholders to implement practices that use fewer resources, reduce climate change and reduce the CSRD's ecological footprint. Developing and implementing a landfill gas upgrading project with Terasen at the CSRD's Salmon Arm landfill site is a great example of how cooperation with industry can accelerate existing plans to align with the provincial government greenhouse gas reduction strategy. Terasen has proved to be a valuable partner in the conceptual development of this project at the Salmon Arm Landfill.

Partnering with Terasen will provide several benefits to the CSRD:

1. **External capital investment will harvest more value from the landfill project.** Without Terasen's capital investment commitment, it is unlikely that the gas capture project at the landfill would have gone beyond the minimum requirements of simply capturing and flaring the gas generated at the landfill. As a regional district, capital budgets are difficult to increase when there is a direct influence on area taxes or fees.
2. **A stable partner**. Working with Terasen, rather than an independent developer reduces long-term financial risk and the assurance that the CSRD will not be left with an abandoned project or a poorly maintained facility.
3. **Established customer service network**. Terasen can provide on-site support for the biogas plant with fully qualified field staff already located in the local area

and the CSRD can avoid additional investment in maintenance. In addition, local Terasen staff will readily be able to call, if necessary, on the knowledge, expertise and resources from elsewhere in their company.

4. **Improved environmental benefits**. By partnering with Terasen, additional environmental benefits can be gained in the form of a more efficient end-use for the gas at the landfill.

If you require any further information, please feel free to contact me at your convenience.

Yours very truly,

Darcy Mooney,
Waste Management Co-ordinator
Columbia Shuswap Regional District

DM

David
Suzuki
Foundation

2211 West 4th Avenue
Suit 219
Vancouver BC
Canada V6K 4S2

604 732 4228 tel
604 732 0752 fax
www.davidsuzuki.org

April 5, 2010

RE: Letter of support for Terasen Gas's initiative to bring renewable biogas to its residential gas customers in BC

Dear British Columbia Utilities Commission (BCUC),

I am writing in support of Terasen Gas's proposal to bring biogas to their residential gas customers in BC.

As an organization that campaigns for climate change and clean energy solutions the David Suzuki Foundation (DSF) supports reducing the greenhouse gas intensity of traditional energy sources while spurring investment in clean energy alternatives. Making biogas an option for residential natural gas consumers is in line with these goals and will create local clean energy jobs while showcasing biogas as a viable alternative.

DSF is fully supportive of this proposal and encourages the BCUC to support this initiative.

Yours sincerely,

Morag Carter

Morag Carter
Director, Climate Change Program

Pacific Carbon Trust

April 27, 2010

Ref: 201006

Terasen Gas Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8
Attention: David Bennett

Dear David:

Re: **Terasen Gas Inc. Renewable Biogas**

Pacific Carbon Trust (PCT) is pleased to prepare this letter of support for the Terasen Gas renewable biogas project which has been filed for approval with the British Columbia Utilities Commission.

Our mandate is to deliver high quality, BC-based carbon offsets to help clients meet their carbon reduction goals and to support the growth of the carbon economy in British Columbia. Terasen's biogas project has the potential to help PCT meet its mandate and also contributes to the Province's commitment to reduce greenhouse gas emissions under the BC Climate Action Plan. This innovative project helps reduce emissions from the waste and agriculture sectors while producing renewable biogas. PCT encourages the development and implementation of these types of projects in British Columbia.

Please feel free to contact me if Pacific Carbon Trust can provide additional information related to our support of the demonstration project.

Sincerely,

D. Scott Macdonald
Chief Executive Officer

Appendix M

CONSULTATION

From:	Webb, Scott
To:	"Bob Blake"; "Bruce Nagel"; Chad Painchaud; "Darryl Parent"; "Debbie White"; Firefly; "Gord Potter"; "James L. Quail"; "James Wightman"; "Jim F. Langley"; John Gaby - Active Energy; "Leanne Albrecht"; "Leigha Worth"; "Mark Dickin"; "Mary McCordic"; "Michael MacPhee"; Michael Stedman; Michelle Vieira; MX Energy; "MxEnergy (Canada) Ltd."; "Nelle Maxey"; Nexen Marketing; "Nick Caumanns"; Planet Energy; "Smart Energy (BC) Ltd."; "Steve Pope"; "Steve Yallouz"; Summitt Energy; Summitt Energy BC L.P.; "Superior Energy Management"; "Susannah K. Robinson"; "Tom Dixon"; Wasney, Judy
Cc:	Hill, Shawn; Regulatory Affairs Terasen Gas
Subject:	Terasen Gas - Proposed Biogas Program
Date:	March 5, 2010 1:42:04 PM
Attachments:	Biomethane Offering - Stakeholder Doc (2).pdf

Dear Gas Marketer,

Terasen Gas is planning to submit an application to the BCUC pertaining to a proposed Biogas Program. This proposal was previously discussed in TGI's 2010 and 2011 Revenue Requirement Application. Terasen Gas is seeking the approval of a new tariff to support the program, as well as authorization to invest in biogas related supply projects. As part of the application process, Terasen Gas seeks feedback from Gas Marketers.

Review process:
All input will be reviewed and considered. Please send this on to anyone else in your respective organizations that may wish to comment. A summary of Gas Marketer input will be included in our application. **Submit your comments by 4:00 pm PST, Monday March 15.**

If you'd like to discuss this or any matter pertaining to Customer Choice, don't hesitate to call me at 604-592-7649.

Sincerely,

Scott

Scott Webb
Manager, Customer Programs and Research

Terasen Gas Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8
P: 604-592-7649
C: 604-788-0341
F: 604-576-7122
scott.webb@terasengas.com

Terasen Gas

Biogas Program

Information for Gas Marketers and Request for Feedback

March 5, 2010

Terasen Gas will soon submit an application to the BCUC seeking approval of a new biogas program. As part of the application process, Terasen Gas seeks Gas Marketer feedback about the proposal.

Table of Contents

1.0 Introduction

Terasen Gas is planning to submit an application to the British Columbia Utilities Commission (the "Commission") later this month for approval of a biogas program that was previously discussed in the 2010 and 2011 Revenue Requirement Application. Terasen Gas will be seeking the approval of a new biomethane tariff as well as investment in biogas supply projects as part of this application. As part of the application completion process, Terasen Gas seeks feedback from Gas Marketers about this proposed program.

2.0 Background

Federal, provincial, regional and municipal governments are increasingly focusing their attention on pollution concerns generally and on climate change specifically, adopting policies in favour of renewable forms of energy as a key part of the solution.

The British Columbia Energy Plan (2007) committed British Columbia to combating climate change by harnessing clean and renewable energy to reduce overall Greenhouse Gas (GHG) emissions. The 2007 plan built on the 2002 plan which focused on low electricity rates, energy security, private sector involvement in oil and gas, and environmental responsibility.

Among the specific goals of the 2007 plan was a desire that utilities explore, develop and propose to the Commission additional innovative rate designs that encourage efficiency, conservation and the development of clean or renewable energy. The Ministry of Environment has also developed regulation for landfills that establishes province-wide criteria for landfill gas capture from municipal solid waste landfills. Terasen Gas proposes that a biomethane offering will help achieve these government goals.

3.0 What is Biogas?

Biogas is produced through the anaerobic digestion of organic material from sources such as landfill sites, wastewater treatment facilities, agricultural waste management and certain industrial processes. It is often referred to as 'renewable natural gas' or 'biomethane'. Sources of biogas include biodegradable materials such as biomass, manure, sewage, municipal waste (including food waste), agricultural waste, and in some cases industrial waste (including food processing waste).

Biogas collection and management systems capture the greenhouse gases that would otherwise be lost naturally directly into the atmosphere. Processing and injecting biogas into the pipeline system provides the benefit of displacing the conventional natural gas commodity with a 'carbon neutral fuel'. Using this fuel allows customers to reduce the carbon footprint created by the use of the conventional natural gas commodity because biogas is considered carbon neutral.

4.0 Green Gas Business Model

For the purposes of this document, the term "Green Gas" is used to describe the specific product offering Terasen Gas is proposing to make available to its customers. This distinction is being drawn because of the differences between the actual biomethane being injected into the Terasen Gas distribution system and the marketing program supporting the Green Gas initiative being offered to customers.

The proposed business model is intended to support a flexible program that can be expanded to all Terasen Gas customers over time as supply builds. The proposed model is not expected to require changes to the Company's current gas supply processes and especially the Essential Service Model that forms the basis of the Customer Choice program. The structure of the program will ensure that the cost associated with the development and acquisition of supply and administrative costs for making the program available to customers are borne by those eligible to participate.

The Company foresees creating a new biomethane tariff to allow eligible customers to either remain on the default commodity rate (e.g., Terasen Gas Standard Rate) or to select the biomethane tariff. The biomethane tariff is expected to be a specific blend of biomethane and conventional natural gas (for example: 10% biomethane and 90% conventional natural gas). The business model selected by Terasen Gas as the basis for implementing the Green Gas program was determined to be the most suitable because it is able to mirror Terasen Gas' current Standard Rate offering, leverage existing systems and infrastructure in order to minimize system impacts and the need to incur incremental costs. The price of the new tariff has not yet been determined but is expected to be at a premium, compared with the default commodity rate.

The proposed business model is designed to leave the Customer Choice program unaffected. Important in this regard is that customers electing to participate in the Green Gas program may not be enrolled in the Customer Choice program and any customer who is enrolled in the Green Gas program and who elects to participate in the Customer Choice program would be automatically removed from the biomethane tariff. The Company proposes to phase-in the implementation of the Green Gas program over a multi-year period starting later this year in order to confirm market interest, demonstrate the ability of producers to deliver a reliable supply of biomethane, and to ensure that processes supporting the business model function effectively.

4.1 *Key Program Features*

- Gas Marketer rules and functionality that are part of the Customer Choice program will remain unchanged. The customer continues to have the choice of a commodity supplier between a Gas Marketer's fixed rate and the Terasen Gas variable rate.
- By electing to remain with Terasen Gas as the commodity supplier, a customer may however choose to remain either on the default rate (e.g., Terasen Gas Standard Rate 1) or select the biomethane option (e.g. Terasen Gas "Rate 1B"), which is understood to be a specific blend of biomethane (e.g. 10% biogas and 90% conventional natural gas).The number of customers eligible to participate in the Customer Choice program and Gas Marketer base load requirements remains unaffected.

- Biomethane rates will be set on a forecasted 12 month period, the non-biomethane commodity portion of a customer's bill will remain subject to quarterly rate adjustments.
- The biomethane tariff will be an open tariff like the Terasen Gas Standard Rate 1 and allows for customers to elect to participate in and exit from the Green Gas program as they see fit.
- The Green Gas program is expected to be introduced in phases, with the initial rollout limited to eligible residential customers.
- Transport customers are not eligible to participate in this offering.

4.2 *Phased Product Offering Approach*

Terasen Gas currently plans on introducing the Green Gas program in two stages. Phase one is expected to be launched in the Fall of 2010. Its primary objectives include the validation of consumer interest and producer reliability, and to demonstrate the success of a flexible, simple, low cost solution.

For phase one of the Green Gas program, customers eligible include those in residential rate 1, where midstream costs are already shown separately on their monthly bill, but exclude those customers who are enrolled with a Gas Marketer in the Customer Choice program. Customers currently enrolled with a Gas Marketer will not be eligible to enroll in the Green Gas program until their contract expires or is terminated. Specifically, eligible residential customers include those on the mainland of British Columbia, but excluding the Sunshine Coast, Powel River, Whistler, Fort Nelson, and Revelstoke. Phase one supply of biomethane is expected to range between a modest 0.05 – 0.26 PJ annually. The program enrollment will be capped based on supply availability, therefore only a small number of customers are expected to be enrolled in the first phase.

The objective of the second phase will be to expand the product offering to match demand once supply has been further established. This phase is foreseen to be launched around the first quarter of 2012. Phase two envisions an expansion of eligible customers to include those in other regions such as Vancouver Island, the Sunshine Coast, Powel River, and Whistler, as well as commercial rate classes 2 to 7. This expansion is conditional on consumer interest and the availability of sufficient supply.

5.0 Conclusion

The Company was particularly mindful of minimizing system process changes in order to deliver a cost-effective solution. Terasen Gas also considered this solution because it does not reduce or limit the number of customers eligible to participate in the Customer Choice program. Customers may continue to elect to contract with a Gas Marketer or remain on the Terasen variable rate, which will be either the default standard rate or a biomethane blend.

Terasen Gas requests comments and general feedback from Gas Marketers about the proposed program by **March 15, 2010** in order to address concerns in the application that is targeted to be filed on March 31, 2010.

just energy
ENERGY MADE EASY

6345 Dixie Road, Suite 200
Mississauga, Ontario L5T 2E6

T 403.462.4299
F 905.564.6069
nruzycki@justenergy.com

March 12, 2010

Terasen Gas
16705 Fraser Hwy
Surrey, BC
V4N 0E8

VIA EMAIL

Attention: Scott Webb
Manager, Customer Programs and Research

Re: Terasen Gas - Proposed Biogas Program

Dear Scott;

Further to your email of March 5, 2010 pertaining to Terasen Gas' Proposed Biogas Program please find the input of Just Energy (B.C.) Limited Partnership ("Just Energy") below.

As a retailer of environmentally friendly "Green Energy" products in British Columbia, Just Energy is working to support the Governments clean energy initiative by offering Natural Gas customers the ability to select clean green energy solutions. Just Energy believes that it is important for all industry members to identify, investigate and develop solutions in keeping with the Governments goals of introducing new clean and renewable forms of energy, reducing Green House Gas emissions and promoting conservation.

Just Energy does not object to Terasen's request for approval of a new tariff to support the proposed biogas program, as well as authorization to invest in biogas related supply projects provided that that the program is introduced in a manner that does not obstruct or pose a detriment to Customer Choice and that no preferential treatment is allotted to Terasen or its customers'.

In Just Energy's view a customer must retain the ability to opt for a retailer's product at anytime at his/her discretion, provided that the customer is not currently contracted with another retailer.

In the stakeholder document Terasen states: "Biomethane rates will be set on a forecasted 12 month period, the non-biomethane commodity portion of a customer's bill will remain subject to quarterly rate adjustments." Just Energy requests that Terasen kindly provide further clarification around the 12 month forecasted period for Biomethane rates in its submission to the BCUC. Also whether a customer must stay on the Biomehtane tariff for the full year or if the customer can freely move to a retail product should he/she desire?

As the tariff rate has yet to be determined for the proposed Biogas Program it is the understanding of Just Energy that a new tariff will be created and filed with the British Columbia Utilities Commission ("Commission") for approval and stakeholder input. This process will allow stakeholders and the Commission the opportunity to understand and question or comment on all components and factors that will comprise the new tariff Rate classification for "Green Gas". An example question is; will a profit be added to the biogas option?

Just Energy submits that it would be concerned if any exemptions (e.g. Carbon Tax Exemption) were allotted to Terasen "Green Gas" customers that retailers and their customers are unable to avail themselves of.

Just Energy appreciates the opportunity to provide its input on this issue.

If you have any questions or require further clarification, please do not hesitate to contact me at 403.462.4299.

Yours truly,

Nola L. Ruzycki
Director, Regulatory Affairs

ACCESS GAS SERVICES

Access Gas Services Inc.
Suite #1–730 Eaton Way
Delta, BC V3M 6J9
Phone: (604) 519-0862
Fax: (604) 519-0873
Toll Free-
1-(877) 519-0862
www.accessgas.com
E-mail:
info@accessgas.com

March 12, 2010

Via Email – scott.webb@terasengas.com

Attn: Scott Webb, Manager, Customer Programs and Research
Terasen Gas Inc. ("TGI")
16705 Fraser Hwy
Surrey, BC V4N OE8

Re: TGI Biogas Program

Dear Mr. Scott Webb,

Pursuant to your email dated March 5, 2010, Access Gas Services Inc. ("AGS") offers the following comments on the Biogas Program proposed by TGI.

For certainty, AGS is adamantly opposed to any offering by TGI (a regulated monopoly) that competes directly or indirectly with the products and services offered by independent natural gas marketers.

AGS cannot support a program that forces a customer to choose between the "green" option provided by TGI and the "green" options provided by many independent natural gas marketers. In addition, AGS finds the fixed price nature of the bio-methane component problematic as it too could appear competitive with the fixed price nature of the products offered by independent natural gas marketers.

Given your program is mutually exclusive and competes directly with independent natural gas marketers, AGS cannot support the program.

Sincerest regards,

Original Signed by Tom Dixon

Tom Dixon
Vice President
Access Gas Services Inc.

Terasen Gas

16705 Fraser Highway
Surrey, BC V4N 0E8
Tel: 604 576-7000
Fax: 604 592-7677
Toll Free: 1-800-773-7001
terasengas.com

May 13, 2010

Chief Leon Nelson
Adams Lake Indian Band
PO Box 588,
Chase BC, VOE 1M0

Dear Chief Nelson:

I am the Aboriginal Relations Manager for Terasen Gas, and I am writing to tell you about an exciting project in the City of Salmon Arm. Terasen Gas is planning to apply to the British Columbia Utilities Commission in the near future for permission to proceed with a project that will allow us to provide more environmentally friendly gas options to our customers. We want to ensure you are provided with information about the project, and give you the opportunity to provide us with any comments or concerns that you may have.

The project involves Terasen Gas constructing equipment on the landfill owned by the Columbia Shuswap Regional District, in the City of Salmon Arm. The equipment will process gas that is naturally produced at the landfill into biomethane, which is a natural Greenhouse Gas neutral alternative to traditional natural gas. The equipment, which will all be located on the landfill, will be limited in footprint and constructed in a manner to make it a non-permanent fixture so that it can be easily removed if and when the project comes to an end.

In addition, the project will require the installation of a connection to an existing distribution line located in the road on 20th Avenue SE, in the City of Salmon Arm, immediately adjacent to the landfill entrance. The connection is approximately 210 meters long, the majority of which is on the landfill property and a small portion of which is on the road. Enclosed with this letter is a drawing showing the location of the new connection.

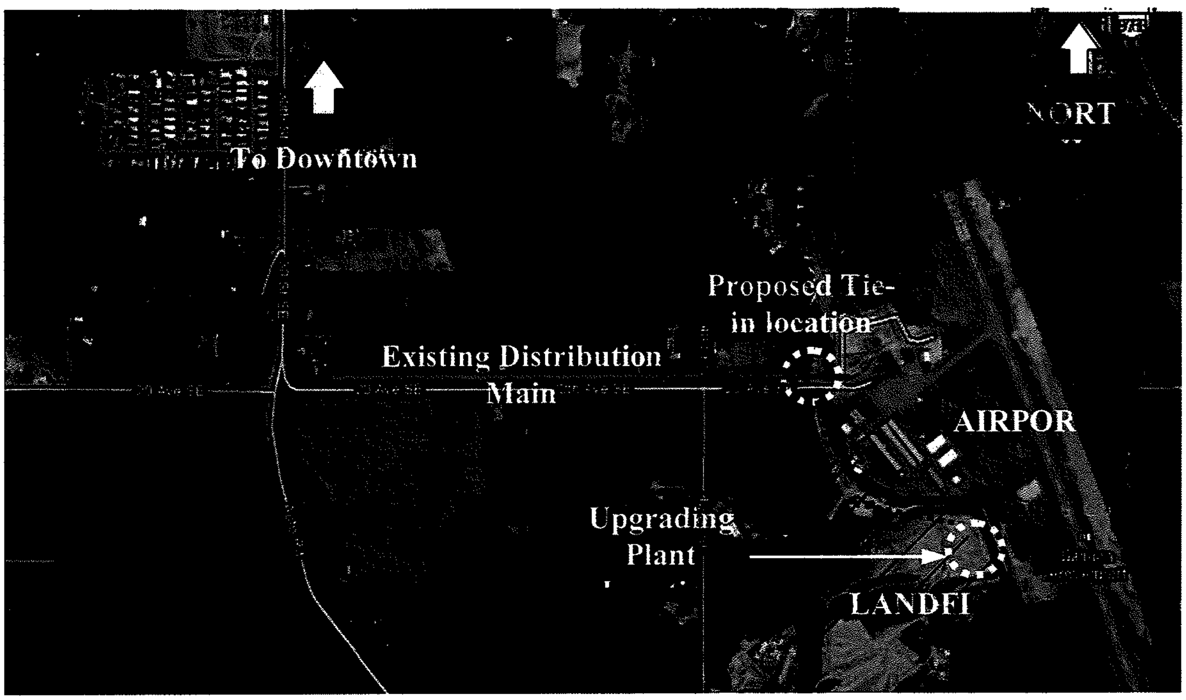
This work will all be done within an existing right-of-way, which is previously disturbed land, and is not located near any rivers or streams. We expect that there will be only minimal impact to the land itself as a result of the installation.

We are happy to discuss any questions or concerns you may have about this project, and ask that your direct any communications to my attention. I can be reached by mail at the below address, by phone at 604-592-7686 or by e-mail at bruce.falstead@terasengas.com.

Thank you for taking the time to read this letter, and we look forward to receiving any input you may have.

Sincerely,

Bruce Falstead
Aboriginal Relations Manager
16705 Fraser Highway
Surrey, BC
V4N 0E8



Terasen Gas

16705 Fraser Highway
Surrey, BC V4N 0E8
Tel: 604 576-7000
Fax: 604 592-7677
Toll Free: 1-800-773-7001
terasengas.com

May 17, 2010

Stó:lō Nation Lands Department
Bldg #8A – 7201 Vedder Road
Chilliwack, BC V2R 4G5

Attenion: Jennifer Tommy & Sara Malloway
Lands Officers

As the Aboriginal Relations Manager for Terasen Gas Inc., I am writing to tell you about an exciting project in the City of Abbotsford. Terasen Gas is planning to apply to the British Columbia Utilities Commission in the near future for permission to proceed with a project east of Abbotsford, which will allow us to provide more environmentally friendly gas options to our customers. We want to ensure that you are provided with information about the project, and give you the opportunity to provide us with any comments or concerns that you may have. In addition, we will notify you when the Application has been filed, and provide you with information on how to review it on the Commission's website: http://www.bcuc.com/.

The project involves Terasen Gas locating equipment on a private farm on Inter Provincial Highway. Catalyst Power Inc. (CPI) will operate a facility on the farm to produce biomethane from agricultural and food wastes. Biomethane is a naturally occurring renewable energy alternative to traditional natural gas. Terasen Gas' equipment will then measure the quality and quantity of the biomethane produced, and accept it into the gas distribution network so that it can be used to supply customers.

The project will also require replacement of an existing distribution line that currently serves Inter Provincial Highway. Our intention is to replace approximately 600 meters of distribution line with a larger 4 inch distribution line in order to accept the biomethane from CPI. The main replacement runs south from CPI's site, at 2016 Inter Provincial Highway, to a location near the intersection of Inter Provincial Highway and Wells Line Road. All work will be conducted within the existing road right-of-way and impacts to the land from this replacement work are expected to be minimal. The replacement work will be carried out in accordance with a Memorandum of Understanding that Terasen Gas has with the Ministry of Environment, which is supported by the Department of Fisheries and Oceans, to ensure that there will be no impacts on the small drainage that runs along side the Inter Provincial Highway.

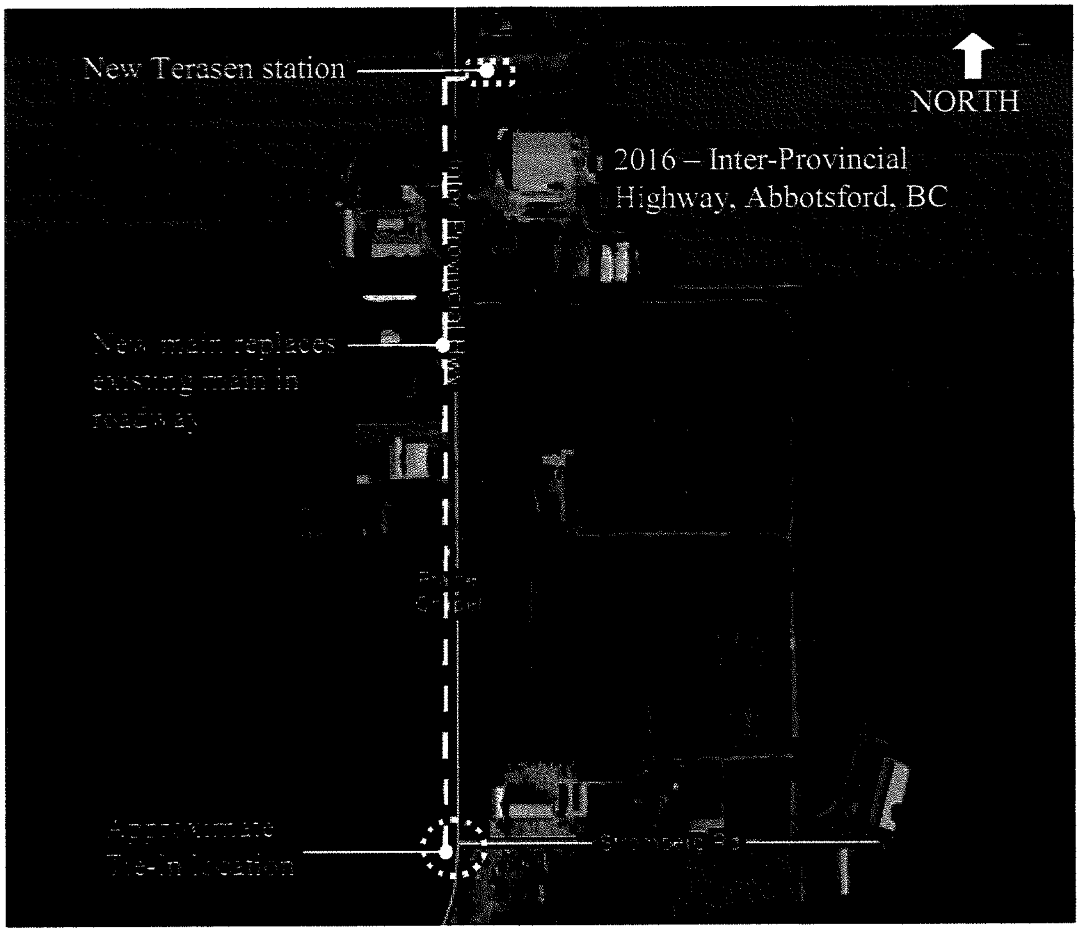
Please do not hesitate to contact me if you have any questions or concerns, or wish to discuss this project further. I can be reached by mail at the below address, by phone at 604-592-7686 or by e-mail at bruce.falstead@terasengas.com.

Thank you for taking the time to review this information. We look forward to receiving any input you may have.

Sincerely,

Bruce Falstead
Aboriginal Relations Manager
Terasen Gas Inc.

Encl.


New Terasen station
NORTH
2016 – Inter-Provincial
Highway, Abbotsford, BC
New main replaces
existing main in
roadway
Approximate
Tie-In location

Appendix N

DRAFT ORDERS AND UNDERTAKING OF CONFIDENTIALITY

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER **G-XX-XX**

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Application by Terasen Gas Inc.
for Approval of a Biomethane Service Offering and Supporting Business Model
and
for the Approval of the Salmon Arm Biomethane Project and
for the Approval the Catalyst Biomethane Project

BEFORE:

(Date)

WHEREAS:

A. On June 8, 2010, Terasen Gas Inc. ("Terasen Gas") filed an application (the "Application") for approval of the rate schedules, related deferral accounts, a cost recovery mechanism and a Biomethane Energy Recovery Charge to support a Biomethane Service Offering; and

B. The Application also sought approval of an expenditure schedule in respect of two Biomethane supply projects, the Salmon Arm Biomethane Project and the Catalyst Biomethane Project, and sought acceptance of the associated energy supply contracts;

C. Terasen Gas has proposed a regulatory timetable for a written process including a workshop and one round of information requests for the review of the Application, followed by written submissions to determine if the parties are agreeable to a Negotiated Settlement Process; and

D. The Commission considers that establishing a written process and regulatory timetable for the review of the Application is necessary and in the public interest.

NOW THEREFORE the Commission orders as follows:

1. The Application will be examined by a written public hearing process and the Regulatory Timetable attached as Appendix A has been established.

2. A Workshop regarding the Application will be held on Thursday, June 24, 2010, commencing at 9:00 a.m. in the Commission Hearing Room on the 12th Floor, 1125 Howe Street, Vancouver, B.C.

3. Terasen Gas is to publish, as soon as possible, in display-ad format, the Notice attached as Appendix B to this Order in the Vancouver Sun and the Province to provide adequate notice to customers served in the affected service area.

4. The Application, together with any supporting materials, will be made available for inspection at the TGI Office, 16705 Fraser Highway, Surrey, BC, V4N 0E8 and at the British Columbia Utilities Commission, Sixth Floor, 900 Howe Street, Vancouver, B.C., V6Z 2N3 and will also be available on the TGI website.

5. Intervenors or Interested Parties should register with the Commission, in writing or electronic submission, by Wednesday, June 23, 2010, and advise whether they intend to attend the Workshop. Intervenors should specifically state the nature of their interest in the Application and identify generally the nature of the issues that they may intend to pursue during the proceeding and the nature and extent of their anticipated involvement in the review process.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <month>, 2010.

BY ORDER

Attachment

REGULATORY AGENDA AND TIMETABLE

Application by Terasen Gas Inc.
for Approval of a Biomethane Service Offering and Supporting Business Model
and
for the Approval of the Salmon Arm Biomethane Project and
for the Approval the Catalyst Biomethane Project

ACTION	**DATES (2010)**
Intervenor Registration	Wednesday, June 23
Workshop (commencing at 9am)	Thursday, June 24
BCUC Information Request No. 1	Wednesday, July 7
Intervenor Information Requests No. 1	Wednesday, July 7
TGI Response to IRs No. 1	Friday, July 23
Written Submissions on Further Process (NSP vs Written Process)	Friday, July 30

Workshop Location:

Commission Hearing Room
12th Floor, 1125 Howe Street
Vancouver, B.C.

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Application by Terasen Gas Inc.
for Approval of a Biomethane Service Offering and Supporting Business Model
and
for the Approval of the Salmon Arm Biomethane Project and
for the Approval the Catalyst Biomethane Project

NOTICE OF WORKSHOP

Date:	Thursday, June 24, 2010
Time:	9:00 a.m.
Location:	BC Utilities Commission Hearing Room 12th Floor, 1125 Howe Street Vancouver, B.C.

THE APPLICATION

On June 8, 2010, Terasen Gas Inc. ("Terasen Gas") filed an application (the "Application") for approval of the rate schedules, related deferral accounts, a cost recovery mechanism and a Biomethane Energy Recovery Charge to support a Biomethane Service Offering. The Application also sought approval of an expenditure schedule in respect of two Biomethane supply projects, the Salmon Arm Biomethane Project and the Catalyst Biomethane Project, and sought acceptance of the associated energy supply contracts.

THE REGULATORY PROCESS

The Commission has established a Written Public Hearing and Regulatory Timetable for the regulatory review of the Application. The Regulatory Timetable can be viewed on the Commission's web site at www.bcuc.com.

INTERVENTION

Persons who expect to actively participate in the Terasen Gas proceeding should register as Intervenors with the Commission, and should identify the issues that they intend to pursue as well as the nature and extent of their anticipated involvement in the review process indicating whether they plan to attend the Workshop. Intervenors will receive email notice of all correspondence, filed documentation and should provide an e-mail address, if available.

Persons not expecting to actively participate, but who have an interest in the proceeding, should register as Interested Parties.

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Intervenors and Interested Parties should register in writing, no later than Wednesday, June 23, 2010. Notification by mail, courier delivery, fax or e-mail is acceptable.

All submissions and/or correspondence received from active participants or the general public relating to the Application will be placed on the public record and posted to the Commission's web site.

PUBLIC INSPECTION OF THE DOCUMENTS

The Application and supporting material, including Commission correspondence, will be made available for inspection at the at the Terasen Gas Inc. Office, 16705 Fraser Highway, Surrey, B.C., V4N 0E8 and at the British Columbia Utilities Commission, Sixth Floor, 900 Howe Street, Vancouver, B.C., V6Z 2N3.

The Application will also be available for viewing on the Terasen Gas website at www.terasengas.com and on the Commission's website at www.bcuc.com.

The Application and supporting materials will be available for inspection at the following locations:

British Columbia Utilities Commission, Sixth Floor, 900 Howe Street
Vancouver, BC V6Z 2N3 Telephone: 1-800-663-1385 **Internet:** www.bcuc.com

Terasen Gas Office
16705 Fraser Highway
Surrey, BC V6N 0E8
Internet www.terasengas.com

For further information, please contact Ms. Erica Hamilton, Commission Secretary, or <BCUC Staff> as follows:

Telephone: (604) 660-4700 BC Toll Free: 1-800-663-1385
Facsimile: (604) 660-1102 E-mail: Commission.Secretary@bcuc.com

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-XX-XX

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

DRAFT ORDER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Application by Terasen Gas Inc.
for Approval of a Biomethane Service Offering and Supporting Business Model
and
for the Approval of the Salmon Arm Biomethane Project and
for the Approval the Catalyst Biomethane Project

BEFORE:

(Date)

WHEREAS:

A. On June 8, 2010, Terasen Gas Inc. ("Terasen Gas") filed an application (the "Application") for approval of the rate schedules, related deferral accounts, a cost recovery mechanism and a Biomethane Energy Recovery Charge to support a Biomethane Service Offering; and

B. The Application also sought approval for an expenditure schedule in respect of two Biomethane supply projects, the Salmon Arm Biomethane Project and the Catalyst Biomethane Project, and sought acceptance of the associated energy supply contracts;

C. The Commission has reviewed the Application, the evidence, and the submissions, and for the reasons set out in the Decision issued concurrently with this order, concludes that the Application should be approved.

NOW THEREFORE pursuant to the provisions of the Utilities Commission Act (the "Act") the Commission orders as follows:

1. The Commission approves Rates Schedules 1B, 2B, 3B, 11B, the amended Rate Schedule 30, and the amendments to Terasen Gas's General Terms and Conditions described in Section 6 of the Application.

2. The Commission will accept, subject to timely filing, the new Rate Schedules 1B, 11B, the amended Rate Schedule 30, and the amendments to Terasen Gas's General Terms and Conditions, in accordance with this Order and Reasons for Decision.

3. The Commission will accept for filing, on or after January 1, 2012, the new Rate Schedules 2B and 3B in accordance with this Order and Reasons for Decision.

4. The cost allocations, deferral accounts, and accounting treatment for the costs associated with the Green Gas program requested by Terasen and described in Section 10 of the Application are approved.

5. TGI may purchase carbon offsets and recover the costs through the Biomethane Variance Account in the event of under-supply of Biomethane, at a per gigajoule unit price not exceeding the difference between the Biomethane Energy Recovery Charge and the Commodity Cost Recovery Charge in effect at that time.

6. The Biomethane Energy Recovery Charge is set at $9.904/GJ effective October 1, 2010.

7. Pursuant to section 71 of the Act, the following energy supply contracts are accepted as filed:

    - the Purchase of Biogas Agreement with the CSRD; and
    - the Purchase of Biogas Agreement with Catalyst Power Incorporated.

8. Pursuant to subsection 44.2(3) of the Act, the following expenditures are in the public interest and are accepted:

    - the expenditures relating to the facilities required for the Salmon Arm Project; and
    - the expenditures relating to the facilities required for the Catalyst Project.

9. Future Green Gas program supply contracts for the purchase of Biogas or Biomethane filed with the Commission that meet the criteria described in section 8, meet the filing requirements described in sections 71(1)(a) and 71(1)(b) of the Act.

10. Terasen Gas is directed to:

- file a report within 5 years of the date of this order that provides the information described in section 8.4.4 of the Application (the "Post-Implementation Report"); and
- hold a post-implementation Workshop, to be attended by Terasen Gas, and any interested stakeholders and intervenors, at which Terasen Gas will address the contents of the Post-Implementation Report.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <MONTH>, 2010.

BY ORDER

Terasen Gas Inc. (“TGI”)
Biomethane Application

Undertaking of Confidentiality

I, *[FULL NAME]*, am a participant acting for *[NAME OF ORGANIZATION]* in the matter of the review of the TGI Biomethane (the “Application”) filed by TGI.

In this capacity, I request access to the confidential information in the Application and any related confidential materials filed in the proceeding including information requests, responses and submissions related to confidential information in the Application. I understand that the execution of this undertaking is a condition of an Order of the Commission, and the Commission may enforce this Undertaking pursuant to the provisions of the *Administrative Tribunals Act.*

I hereby undertake

a) to use the information disclosed under the conditions of the Undertaking exclusively for duties performed in respect of this proceeding;
b) not to divulge information disclosed under the conditions of this Undertaking except to a person granted access to such information or to staff of the Commission;
c) not to reproduce, in any manner, information disclosed under the conditions of this Undertaking except for purposes of the proceeding;
d) to keep confidential and to protect the information disclosed under the conditions of this Undertaking, including by means of filing information requests that refer to confidential materials separately, in confidence, such that they are available only to those individuals who have executed this Undertaking;
e) to return to TGI, under the direction of the Commission, all documents and materials containing information disclosed under the conditions of this Undertaking, including notes and memoranda based on such information, or to destroy such documents and materials and to file with the Commission a certification of destruction at the end of the proceeding or within a reasonable time after the end of my participation in the proceeding; and
f) to report promptly to the Commission any violation of this Undertaking.

Dated at *[CITY, PROVINCE]* this *[DAY OF MONTH]* day of *[MONTH]* 2009.

Signature: ______________________________

Name: ______________________________
(please print)

Address: ______________________________

Telephone: ______________________________

Fax: ______________________________

E-mail: ______________________________