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May 28, 2013

Via Email
Original via Mail

BC Sustainable Energy Association
c/o William J. Andrews, Barrister & Solicitor
1958 Parkside Lane
North Vancouver, B.C.
V7G 1X5

Attention: Mr. William J. Andrews

Dear Mr. Andrews:

Re: FortisBC Energy Inc. (FEI)

Biomethane Service Offering: Post Implementation Report and Application for Approval for the Continuation and Modification of the Biomethane Program on a Permanent Basis (2012 Biomethane Application) (the Application)

Response to the BC Sustainable Energy Association (BCSEA) Information Request (IR) No. 1

On December 19, 2012, FEI filed the Application as referenced above. In accordance with the British Columbia Utilities Commission Order G-53-13 setting out the Regulatory Timetable for review of the Application, FEI respectfully submits the attached response to BCSEA IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed by: Ilva Bevacqua

For: Diane Roy

Attachments

cc (e-mail only): Commission Secretary
Registered Parties

1.0 Topic: Requested approvals

Reference: Exhibit A-11, Order G-53-13, section 2; Exhibit B-1, Appendix K, Draft Order

"2. The scope of the FEI 2012 FEI Biomethane Application proceeding will exclude the FEI requests made under section 44.2 and subsection 71(1) of the *Utilities Commission Act* related to Dicklands Farms, Earth Renu Energy Corp., and Seabreeze Farm Ltd. These excluded requests from FEI will be addressed in the FEI Biomethane Third-Party Suppliers Regulatory Process set out in Order G-46-13.

1.1 Please list the approvals FEI is currently requesting in this proceeding.

Response:

FEI seeks the following approvals pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA):

- Continuation of Rate Schedules 1B, 2B and 3B, and amendments to the same;
- Continuation of Section 28 and related Definitions of FEI's General Terms and Conditions (GT&Cs), and amendments to the same;
- Continuation of Rate Schedules 11B and 30 as part of FEI's Biomethane Program;
- Continuation of the cost allocations and accounting treatment for the costs associated with the Biomethane Program, including the continuation of the Biomethane Variance Account, the quarterly reporting process and the Biomethane Energy Recovery Charge (BERC) rate setting mechanism;
- The resetting of the BERC rate at $12.001/GJ to be effective at the start of the first quarter after the Commission's Decision on the 2012 Biomethane Application;
- Continuation of FEI's ability to 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 BERC and the Commodity Cost Recovery Charge in effect at that time; and
- Approval of the recovery of costs in the Biomethane Variance Account through the Midstream Cost Recovery Account as set out in Section 8 of the 2012 Biomethane Application;
- FEI also seeks approval that future supply contracts for the purchase of biogas or biomethane filed with the Commission that meet the criteria described in Section 6 of the 2012 Biomethane Application, meet the filing requirements in sections 71(1)(a) and 71(1)(b) of the UCA.

The acceptance of the four supply agreements under section 71 of the UCA and the capital expenditures of the related facilities under section 44.2 of the UCA are not required in this proceeding as Commission Order G-70-13 approved the Dicklands, Seabreeze and Earth Renu supply contracts as rates and accepted the related interconnection capital costs. FEI anticipates that a separate process for review of the Greater Vancouver Sewage and Drainage District supply contract and related interconnection capital costs will begin when an exemption is granted for the regulation of biomethane suppliers pursuant to the exemption process initiated by the Commission.

1.2 Please provide an updated draft order.

Response:

An updated draft order is provided in Attachment 1.2.

2.0 Topic: Application

Reference: Exhibit B-1, Appendix A

FEI appended portions of the Terasen Gas Inc. (now FEI) 2010 Biomethane Application as Appendix A to this application.

2.1 Please provide a summary, with explanations as necessary, of which parts of Appendix A are still current in the present review.

<u>Response:</u>

FEI filed TGI's 2010 Biomethane Application for reference purposes in the current Application as it was FEI's original biomethane program proposal and was referenced in several places in the Application. The current Application has remained largely consistent with the proposals in TGI's 2010 Biomethane Application, although it has updated information on supply and demand and requests for amendments to the program. Much of the information in TGI's 2010 Biomethane Application is still current, such as in sections 2, 3, and 4.

2.2 Several cover sheets in Appendix A bear the phrase "view attachments panel"; however the referenced documents appear not to have been attached. Please explain, or submit the relevant documents, as the case may be.

<u>Response:</u>

FEI inadvertently did not attach the relevant documents originally filed and referenced in excerpts from the 2010 Biomethane Application with the 2012 Application (Exhibit B-1) in Appendix A. Please refer to Attachment 2.2 for the relevant documents. In an effort to conserve paper, Attachment 2.2 is being provided in electronic format only.

3.0 Topic: Customer segmentation

Reference: Exhibit B-3, FEI Biomethane Pilot Program: Post Implementation Summary Report, 2. Customer Segmentation and Targeting

3.1 Please explain how the term "customer segmentation" relates to rate schedules. Is there a one-to-one relationship between customer segments and rate schedules?

Response:

Customer segmentation refers to the dividing of customers according to common characteristics. Customer segments may correspond to rate schedules, but the relationship between customer segments and rate schedules is not necessarily one-to-one.

At a broad level, FEI segments its customers into residential, small and large commercial. At this level, customers segments are broader than the rate schedules. FEI can further segment the customers within those categories using factors such as demographic, region and behavior. As an example, FEI could internally segment its RNG residential customers under Rate Schedule 1B (RNG rate for single-family residences and separately metered multi-family residences) into eight segments as described in Exhibit B-4 slide 12 of the PIR Biomethane workshop presentation. Depending on their characteristics, commercial customers are further segmented by sector, and may either be in Rate Schedule 2b, 3b or 11B depending on if they buy the commodity through FEI or gas marketer.

4.0 Topic: Location of Biomethane customers

Reference: Exhibit B-3, FEI Biomethane Pilot Program: Post Implementation Summary Report, 2. Customer Segmentation and Targeting, 2.1 Residential Customers

"More than 65 percent of the participation [of residential customers] is coming from the Lower Mainland." [p.3]

4.1 How does 65% of residential RNG participation coming from the Lower Mainland compare to the number of residential customers in the Lower Mainland as a percentage of the number of residential customers who are eligible to participate in the RNG program?

Response:

Residential customers in Lower Mainland represent 70 percent of the total residential customers who are eligible to participate in RNG in Lower Mainland, Columbia and Inland regions. The fact that 65 percent of current residential RNG customers came from Lower Mainland is aligned with the breakdown of the overall eligible customer population.

5.0 Topic: PSO market for biomethane

Reference: Exhibit B-3, FEI Biomethane Pilot Program: Post Implementation Summary Report, 2. Customer Segmentation and Targeting, 2.2 Commercial Customers

"An emerging secondary market within the commercial category that was not identified in the original market research is public sector organizations ("PSO"s). PSOs are currently mandated to be carbon neutral through government policy[1] and view Biomethane as an alternative to buying offsets in order to reach their carbon neutrality goals. Other PSOs are developing co-generation projects using Biomethane to meet BC Hydro's clean energy criteria[2] for the Standing Offer Program or Load Displacement Agreements." [p.4, underline added]

"Additionally, PSO"s and organizations looking at developing cogeneration projects using biomethane represent new market potential for Biomethane sales." [p.4]

5.1 Please describe in more detail the co-generation projects being developed by some public sector organizations for

5.1.1 BC Hydro's Standing Offer Program, or

5.1.2 Load Displacement Agreements.

Response:

BC Hydro's website includes a table with all the awarded SOP's and another table of current applications (as of April 2013) that are under review but that have not yet been awarded any energy purchase agreement.[1] FEI has reviewed this information but is unaware which, if any, of these projects fall into the category of "PSOs [that] are developing co-generation projects using Biomethane."

5.2 What makes these projects "co-generation"? Presuming that electricity is one product, what is the other product(s)?

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[1] http://www.bchydro.com/energy-in-bc/acquiring_power/current_offerings/standing_offer_program/current_applications.html.

Response:

Cogeneration or combined heat and power (CHP) is the use of a heat engine or power station to simultaneously generate electricity and useful heat.

5.3 Would the currently available 10% blend of biomethane and regular natural gas meet BC Hydro's criteria for clean energy under its Standing Offer Program?

Response:

FEI is not aware of any special concessions for biomethane / natural gas blends in the Standing offer program (SOP) rules. In other words a 10 percent biomethane blend would not meet the definition of clean or renewable energy in the SOP. It is clear that electricity generated from 100 percent biogas (or biomethane), which qualifies as a clean or renewable resource, would be eligible for the SOP. It is also clear that projects that meet the criteria for a high efficiency co-generation project can use conventional natural gas as an energy source and qualify for the SOP. However, it is FEI's understanding that a project using a 10 percent biomethane / 90 percent natural gas blend (or a different blend) would also have to meet the high efficiency cogeneration criteria in order for a project to qualify for an SOP energy purchase agreement.

The glossary in BC Hydro's Standing Offer Program, Program Rules Version 2.2, dated March 2013, includes the following definition of High-Efficiency Co-Generation Facility:

> **High Efficiency Co-Generation Facility** means a facility that:
>
> a. uses a prime mover (steam turbine, gas turbine, or internal combustion engine) to simultaneously generate both electricity and steam or heat using natural gas as the fuel source; and
>
> b. is designed to be capable of achieving a minimum overall efficiency rate of 80% based on the gross power output from the facility and the fuel lower heating value, as certified by an independent professional thermal engineer acceptable to BC Hydro. The engineer must be registered or licensed in a jurisdiction that regulates the practice of engineering.
>
> Co-generation projects that use a fuel other than natural gas may be eligible at the discretion of BC Hydro. Developers of co-generation projects that use a fuel other than natural gas should contact BC Hydro for a preliminary assessment of the eligibility of the proposed fuel and facility. BC Hydro may require any such Developer to conduct one or more studies, at the Developer's cost, to demonstrate that the facility is a high efficiency co-generation facility.

5.4 Assuming that a co-generation project used 100% biomethane from FEI to generate electricity and some other energy product(s), please discuss the pros and cons of whether this is a desirable use of biomethane. For example, does the 'co-generated' energy product contain enough energy to make up for the physics fact that using biomethane directly for heat is more efficient than using biomethane to generate electricity to make heat?

Response:

The primary reason why a co-generation facility would use 100 percent biomethane would be to avoid emissions associated with generation of electricity while at the same time avoiding emissions from natural gas use for heating. The net efficiencies are project specific and need to consider alternatives for generating heat as well as where the electricity is delivered and what the characteristics of the electricity displaced are.

In general, well-designed Combined Heat and Power (CHP) systems have overall system efficiencies in the 80 percent range. This is consistent with standard boiler technology. Therefore, biomethane used in a CHP application is at least as efficient as a standard boiler.

FEI has conservatively estimated the efficiency of an upgrading system at approximately 76 percent (refer to the response to CEC IR 1.29.3). If this is combined with the typical estimated efficiency of 80 percent for a CHP application, the final combined efficiency of a CHP system using biomethane is approximately 60 percent. Therefore, when using biomethane in a CHP application, the efficiency is much higher than that expected if raw biogas is used for electricity generation (in the range of 35 percent). This fact provides a strong argument for the use of biomethane in CHP applications as it provides both a carbon neutral source of electricity and is a better (more efficient) use of the raw bio-resource. FEI has also discussed the concept related to efficient use of energy in the responses to CEC IRs 1.28.1 – 1.28.9 and CEC IR 1.29.1.

However, the actual heat delivered by a CHP system would be less than a boiler, because part of the energy is used to generate electricity. This could require additional biomethane to meet the same heating load.

Looking solely at the heat load, high-efficiency condensing boilers can have an efficiency of as much as 95 percent, so there may be a 15 percent loss in potential efficiency on the heating component

Looking at the electricity component, regardless of the additional biomethane required, the electricity generated can also be considered marginally less GHG intensive that the BC Hydro supply pool, providing some environmental benefit. In addition, the electricity generated by a CHP facility is generally delivered into the heart of a load centre without transmission system losses.

In summary, the specific net efficiencies will be project specific, but the overall efficiency of a CHP system operating on biomethane can be expected to be competitive with existing alternatives.

5.4.1 Would using biomethane to generate electricity have the effect of separating the location of the production of the biomethane, which might be outside of the electrical load centre, from location of the generation of the electricity, which could be within the electrical load centre? Is that a value-added factor?

Response:

Yes. By making use of the concept of displacement, biomethane could be used at any location served by the natural gas distribution grid, regardless of the location of the injection.

This provides much greater flexibility for siting electricity generation. For example, in the case of the potential project at UBC, biomethane injected into the FEI distribution system could be used at UBC. FEI understands that this concept allows UBC to generate clean electricity while at the same time solving a problem of increasing load at the campus. The generation near the load will also provide a means of avoiding the capital associated with re-enforcing electricity transmission from Vancouver onto the campus.

5.5 What is a Load Displacement Agreement? How would a co-generation project using biomethane support a Load Displacement Agreement?

Response:

A Load Displacement Agreement is an agreement with BC Hydro under BC Hydro's load displacement incentive program that provides incentives for energy generation projects to generate energy to displace all or part of the customer's site electrical load and decrease the electricity consumption supplied by BC Hydro.

Biomethane fits the definition of a clean or renewable resource under the *Clean Energy Act*, therefore can be used in co-generation projects that qualifies under BC Hydro's load displacement incentive program.

For more information about the incentive program and process, please refer to BC Hydro's Integrated Customer Solutions Process and Proposal Submission Guide, which is available online at: http://www.bchydro.com/energy-in-bc/customer-based_generation.html.

6.0 Topic: Biomethane products

Reference: Exhibit B-3, FEI Biomethane Pilot Program: Post Implementation Summary Report, 3.2 Commercial and On-System Sales Uptake

"In addition to Rate Schedules 2B and 3B, FEI also offered bulk sales of Biomethane through Rate Schedule 11B – Biomethane Large Volume Interruptible Sales (Rate Schedule 11B allows for the bulk sale of Biomethane to on-system transportation only customers, who currently receive service from FEI under a transportation service schedule (Rate Schedules 22, 23, 25, or 27)." [p.6]

6.1 Please confirm that "On-System Sales" refers to sales of Biomethane through Rate Schedule 11B.

Response:

Confirmed. Rate Schedule 11B allows customers to purchase a select amount of Biomethane, therefore it is not limited to a blend option, rather it is a bulk purchase of biomethane that is deposited in the gas marketers or customer account to be directed to the transportation customer and is priced at the existing BERC rate.

6.2 Is the Biomethane sold through Rate Schedule 11B a 10%/90% blend or 100% Biomethane?

Response:

Please refer to the response to BCSEA IR 1.6.1.

6.3 How is the Biomethane sold through Rate Schedule 11B priced?

Response:

Please refer to the response to BCSEA IR 1.6.1.

6.4 Please provide a table showing the various Biomethane rate schedules, the corresponding ‘regular’ rate schedules, a brief description of the Biomethane product (e.g., 10% blend), and a brief description of the pricing mechanism (e.g., 10% premium).

Response:

Biomethane Rate Schedules	Description	Product	Premium	Corresponding Rate Schedule
Rate Schedule 1B	for single-family residences and separately metered multi-family residences	10% blend – 10% of natural gas use charged at the BERC rate 90% of natural gas use charged at the current Cost of Gas	At current prices this works out to $7.23 more per GJ on the 10% portion (net of carbon tax) or about 10% more to the overall bill*	Rate Schedule 1
Rate Schedule 2B	Small commercial renewable natural gas rate for businesses with consumption of less than 2,000 GJ annually	10% blend – 10% of natural gas use charged at the BERC rate 90% of natural gas use charged at the current Cost of Gas	At current prices this works out to $7.23 more per GJ on the 10% portion (net of carbon tax) or about 10% more to the overall bill*	Rate Schedule 2
Rate Schedule 3B	Large commercial renewable natural gas rate for businesses with consumption of greater than 2,000 GJ annually	10% blend – 10% of natural gas use charged at the BERC rate 90% of natural gas use charged at the current Cost of Gas	At current prices this works out to $7.23 more per GJ on the 10% portion (net of carbon tax) or about 10% more to the overall bill*	Rate Schedule 3

Biomethane Rate Schedules	Description	Product	Premium	Corresponding Rate Schedule
Rate Schedule 11B – on system	On-system interruptible sales rate for customers entering into a contract for the short-term sale and purchase of biomethane	Bulk purchases of biomethane at a select volume amount for sales within FEI's service territory	BERC Rate	N/A (only through high-end charges)
Rate Schedule 30 / GasEDI – off system	Off-system interruptible sales rate for customers entering into a contract for the short-term sale and purchase of natural gas	Bulk purchases of biomethane at a select volume amount for sales outside of FEI's service territory	BERC Rate	Rate Schedule 30/ GasEDI

*10 percent of average annual consumption

- Residential – 10 percent of average usage is 9.5 GJ x $7.23 = $68.69 additional per year for renewable natural gas
- Small commercial rate 2 – 10 percent of average usage is 30 GJ x $7.23 = $216.90 additional per year for renewable natural gas
- Large commercial rate 3 – 10 percent of average usage is 300 GJ x $7.23 = $2,169 additional per year for renewable natural gas

The cost of gas* as of January 1, 2013 (90% of GJs) is $2.977 GJ and the renewable natural gas* cost as of January 1, 2013 (10% of GJs) is $11.696 GJ.

At today's prices, this works out to $7.23 more per GJ (price net carbon tax $1.49 / GJ) on the renewable natural gas portion.

7.0 Topic: Residential customer education

Reference: Exhibit B-3, FEI Biomethane Pilot Program: Post Implementation Summary Report, 4.2 Residential Customer Education

"As shown below in Figure 4-1, the most effective communication channel to reach residential customers has been FEI's bill inserts." [p.9]

7.1 Does FEI use RNG bill inserts with residential bills that are distributed electronically? If so, how is this done? If not, is FEI considering doing so, given the success of hardcopy bill inserts?

Response:

Yes, FEI does send out an electronic version of the paper bill inserts with the RNG content and messaging to those customers that opted for ebilling. This is sent electronically via email with a link to view bill inserts online. All customers get the same link regardless of whether they are residential or commercial.

7.2 What percentage of residential customer bills is distributed electronically?

Response:

Approximately 12 percent of our residential customers receive bills electronically

"For commercial customers, the key success factor has been targeting businesses that are leaders in sustainability and providing recognition to organizations that sign up for the RNG Offering. Organizations that sign up are featured as Green Leader businesses on FEI"s website, are provided decals (printed and digital) they can use to display at their business, receive tweets about their participation in the RNG Offering and are featured in a Thank You ad once per year. FEI featured early adopters in customer education promotions to encourage other businesses in similar industries to sign up, which has been an effective way to gain businesses" interest." [p.10, underline added]

7.3 Has FEI considered providing <u>residential</u> RNG customers with printed or digital decals, for purposes of motivation, reward and public awareness?

<u>Response:</u>

Yes, FEI is currently sending its current subscribers magnets and welcome letters, including AIRMILES, as part of its ongoing efforts to create awareness, reward and retain subscribers.

8.0 Topic: Commercial customer education

Reference: Exhibit B-3, FEI Biomethane Pilot Program: Post Implementation Summary Report, 4.3 Commercial Customer Education,

"For commercial customers, the most effective channels so far have been direct sales and bill inserts." [p.10]

8.1 Does FEI use RNG bill inserts with commercial customer bills that are distributed electronically? If so, how is this done? If not, is FEI considering doing so, given the success of hardcopy bill inserts?

<u>Response:</u>

Yes, when customers receive an ebill, there is a link in the email to view the bill inserts online. All customers get the same link, regardless of whether they are residential or commercial.

8.2 What percentage of commercial customer bills is distributed electronically?

<u>Response:</u>

Approximately 8 percent of commercial customer bills are distributed electronically.

9.0 Topic: Enrolment, drops and attrition

Reference: Exhibit B-3, FEI Biomethane Pilot Program: Post Implementation Summary Report, 5 Enrolment And Attrition Rates

"FEI experienced a 6 percent and 7.6 percent drop rate in 2011 and 2012, respectively. <u>In order to properly determine attrition rates, one must determine whether dropped customers represent customer actually moving back to the standard rate, or customers that have moved, transferred accounts, or disconnected</u>. Based on a sample of 175 dropped accounts, only 20 percent of those accounts sampled requested to be removed from the RNG Offering. The other drops were predominantly a result of a customer moving. Given this information, FEI believes an attrition rate of 1 percent in 2011 and 1.5 percent in 2012 more accurately portrays the true attrition rate of the program, i.e. those that returned back to the standard rate. FEI has therefore used these drop rates in its future forecasts. In both scenarios the RNG Offerings attrition rate is well below the 2010 industry average of a 7 percent drop rate of other green pricing programs, described in further detail in Exhibit B-1, Appendix F-1." [p.12, underlined added]

9.1 Please explain the reasoning for the statement that "In order to properly determine attrition rates, one must determine whether dropped customers represent customer actually moving back to the standard rate, or customers that have moved, transferred accounts, or disconnected."

<u>Response:</u>

FEI believes that a true attrition rate represents customers that are no longer satisfied with the program and, therefore, leave the RNG tariff to return to the standard rate. However, because of the way our system works, every time a customer moves, transfers accounts, or is disconnected, they are automatically removed from RNG and recorded as a dropped customer, whether or not they continued with the RNG program or returned to the standard rate. For example, if a customer moves, but returns to the RNG rate at their new residence, then FEI would not consider this to represent a drop out of the RNG program. If the customer moves, and does not sign up for RNG at the new residence, then FEI would consider this to represent a true dropped customer.

We have conducted analysis which demonstrated that 39 percent of customers who are recorded as "dropped customers" actually returned to the RNG tariff after being removed from the RNG tariff due to a move or disconnection. The analysis also showed that 42 percent moved out of their premise and dropped from RNG, and did not return to RNG. This may be because the customer left the FEI service territory or because they consciously chose not to return to RNG at their new premise. Another 20 percent dropped from the RNG rate, Rate

Schedule 1B, maintained at their current premise, and returned to the standard natural gas rate, Rate Schedule 1.

9.2 What is the definition of "attrition rate"? "drop rate"?

Response:

"Attrition rate" and "drop rate" are interchangeable and is defined as the percentage of loss of RNG customers over a defined period of time.

9.3 On the assumption that "drop rate" is defined in relation to the number of program participants in a certain time period, does FEI use a corresponding measure such as 'join rate,' defined as the number of new participants in relation to the number of program participants in a time period?

Response:

FEI tracks new enrollment but does not use a corresponding 'join rate' as it is defined above.

9.4 For forecasting purposes, why does the customer's reason for discontinuing participation in the RNG program matter?

Response:

Please refer to the response to BCSEA IR.1.9.1.

The reason for discontinuing participation in the RNG program matters more when trying to assess the success of the program than it matters for forecasting purposes. When using the attrition rate to determine if customers are satisfied with the program, FEI must take into consideration those customers who are dropped from the system but return to the RNG tariff immediately/shortly thereafter due to a move, transfer, or disconnection.

10.0 Topic: RNG demand forecast

Reference: Exhibit B-3, 6 Customer Demand Forecast for Next Ten Year Period; Exhibit B-1, 4. Demand in B.C.

10.1 Please confirm that the figures for demand (i.e., GJ/y) for Biomethane (or Renewable Natural Gas) is in terms of 'pure' Biomethane, as opposed to quantities of a blended product.

Response:

Confirmed.

FEI demand forecasts are in terms of 'pure' Biomethane.

Customers who sign up for the Biomethane tariff (1B, 2B, 3B) currently elect to purchase a 10 percent blend of Biomethane.

10.2 For Figure 6-1 in Exhibit B-3, please confirm that the y-axis is in units of GJ/year.

Response:

Confirmed.

10.3 For the Current Supply line in Figure 6-1 in Exhibit B-3, please specify for clarity what projects are the sources of this supply.

Response:

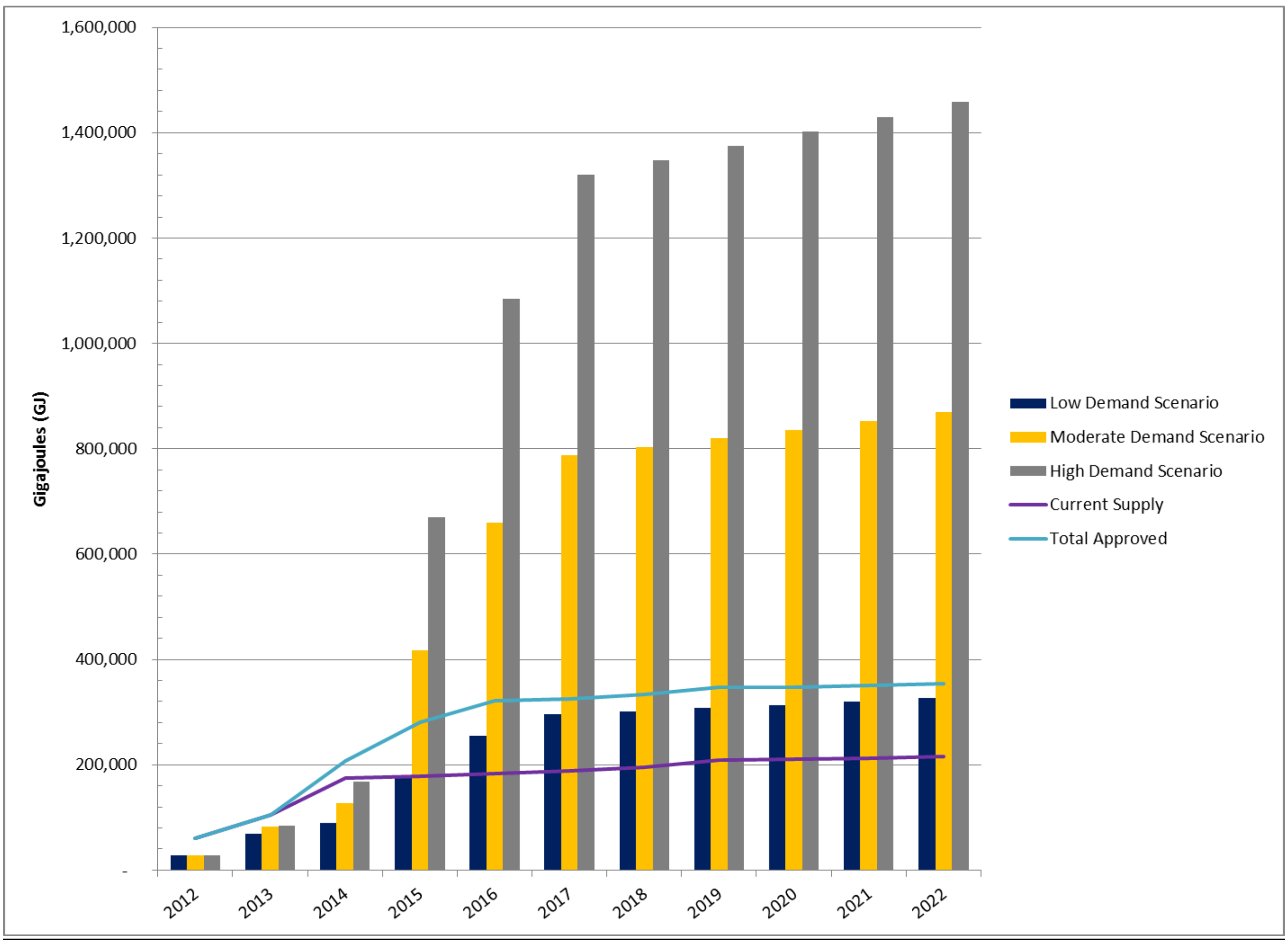
The Current Supply line was based on all projects that were approved at the time the exhibit was filed. It includes the following three projects:

- Fraser Valley Biogas
- Salmon Arm Landfill
- Kelowna Landfill

10.4 Please provide a version of Figure 6-1, Exhibit B-3, that shows both Current Supply (as is) and supply with the addition of the proposed supply from the Third Party Suppliers under review in Commission Project No.3698707.

Response:

Please refer to the figure below. Note that the "Total Approved" in the figure below includes the supply from the third-party suppliers that has been approved by BCUC Order G-70-13. "Total Approved" does not include the project proposed by the GVS&DD (Metro Vancouver) that is described in the Application.



11.0 Topic: Biomethane supply

Reference: Exhibit B-1, page 70; and Tables 5-3 and 5-4, page 71

11.1 Please reconcile the 30,000 GJ/yr forecast average volume of biomethane cited in the text with the 20,000 GJ/y amount in Table 5-3.

Response:

The volume of biomethane at the Salmon Arm Landfill is expected to increase over the life of the contract from approximately 20,000 GJ per year (first full year) to approximately 40,000 GJ/year.

30,000 GJ/year is the *average* expected volume over the life of the project. It is derived by dividing the total amount of expected biomethane over the contract term by 15 years.

11.2 Please confirm that the 15 TJ forecast volume in Table 5-4 pertains only to 2012 and not to subsequent years. Alternatively, please explain.

Response:

Confirmed. 15 TJ (15,000 GJ) is a prorated volume based on the expected operating time of 75 percent for the 2012 year (20,000 x 75% = 15,000) only.

12.0 Topic: Biomethane supply

Reference: Exhibit B-1, sections 5.2 and 5.3, pp. 72 – 74; Table 5-6.

Sections 5.3.1 and 5.3.2 have a description of a biogas supply forecast in which there is an initial supply volume of 60,000 GJ in the initial year of operation; an average forecast volume of 64,000 GJ/y or 88,000 GJ/y "over the full term of the contract," and a "potential maximum volume" of 118,000 GJ/y.

12.1 Please confirm that Table 5-6 refers to the City of Kelowna Landfill project and not the Salmon Arm Landfill Biogas Project. Alternatively, please reconcile Table 5-6 with Tables 5-3 and 5-4.

Response:

Table 5-6 refers to the *City of Kelowna* Landfill. It was erroneously labeled in the Application.

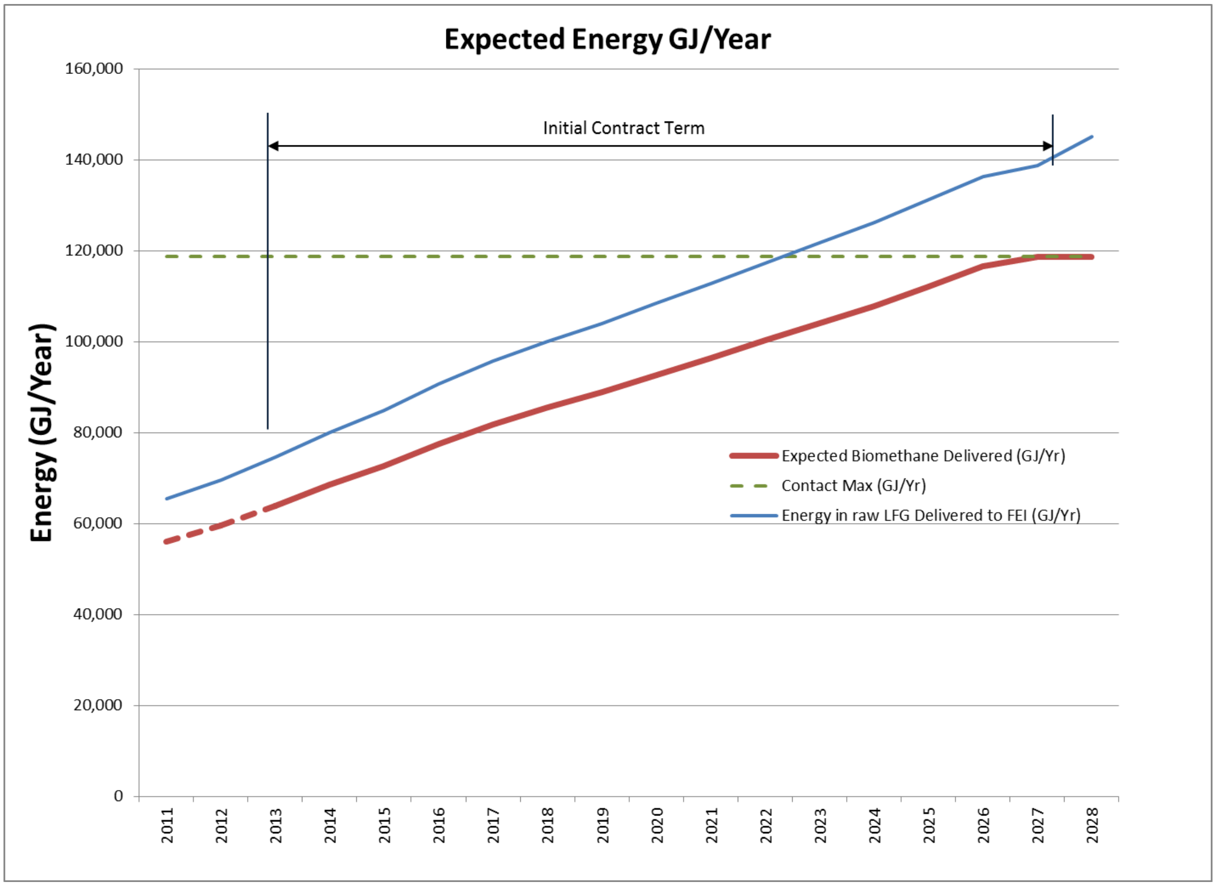
12.2 Please explain in more detail the volumes of biomethane that FEI expects to receive from the City of Kelowna Landfill Biogas Project:

12.2.1 Does FEI expect the volumes of biomethane supply to follow a trend over the years, or to fluctuate unpredictably between average, maximum and minimum volumes? Please explain.

Response:

Yes, FEI expects the volume to follow a general trend over the years. Specifically, FEI expects the volume to increase over the life of the contract and remain stable on a daily basis. Generally, the volume of gas available will increase over time as more waste is added to the landfill. That volume should increase roughly linearly over time beginning in year one at approximately 60,000 GJ/year and ending year 15 at approximately the contract maximum of 118,000 GJ/year. FEI is installing a biomethane plant capable of processing landfill gas across the expected range for the life of the project.

The expected energy curve which was provided with the Kelowna Application is provided here for reference.



Variations over time will be a result of two factors. First, any large fluctuations will be a result of operational issues with either Kelowna equipment (gas collection system) or FEI equipment (upgrading plant). These fluctuations are expected to be relatively infrequent and for short durations (hours or days). Secondly, the volume may make step changes upward. These step changes would be a result of the manner in which Kelowna builds its gas collection infrastructure. This will likely be done on a yearly or bi-yearly basis. Therefore, the amount of gas may increase in blocks of volume as multiple wells are added over a relative short period of time, followed by periods of relatively little growth in volume.

12.2.2 How much annual variation in biomethane does FEI expect from the City of Kelowna Landfill Biogas Project?

Response:

FEI expects the volume to increase yearly. The projections indicate that the amount of energy will increase by approximately 4,000 GJ per year on average. Please refer to the figure provided in the response to BCUC IR 1.12.2.3.

12.2.3 Do the expected volumes of biogas relate in some way to the life cycle of the City of Kelowna's landfill site? Please explain.

Response:

Yes.

Assuming that waste is not being added to landfill, there is a natural curve associated with the production of landfill gas containing methane. This curve generally increases over a period of years and is followed by a decrease in gas production. The gas generation curve for the Kelowna Landfill (aka the Glenmore Landfill) was originally filed as part of the Kelowna Biomethane Application and is included here for convenience. Note that during the period of the contract the expected gas production rises.

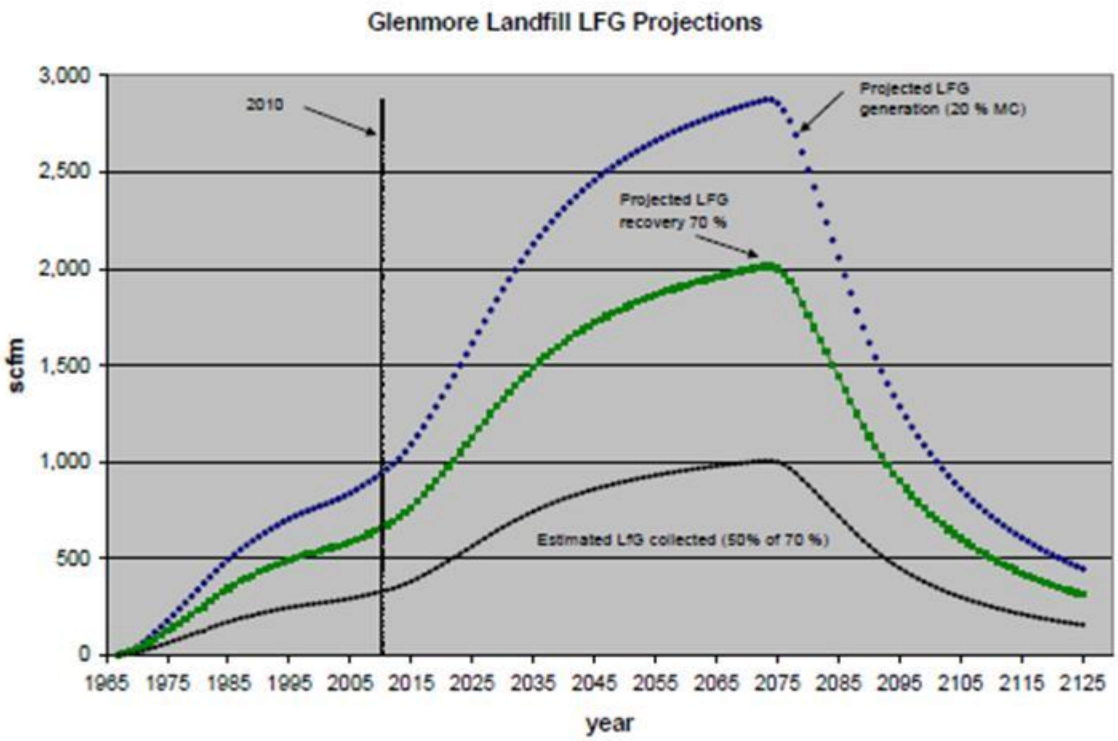


Figure provided courtesy of the City of Kelowna

12.2.4 Does the term of the supply contract with the City of Kelowna bear any relationship with the life cycle of the landfill site?

Response:

Yes. The contract was structured to allow for the expected increase in the annual volume over the term.

12.3 Does the expected profile of biomethane supply with the City of Kelowna Landfill Project represent a typical profile of biomethane supply that could be expected for landfill biomethane supply projects in B.C. generally?

Response:

Yes. FEI believes that this is typical for landfills.

In general, as more waste is added to a landfill over time there will be more landfill gas produced and therefore more biomethane available.

13.0 Topic: Biomethane supply

Reference: Exhibit B-1, Appendix A: 2010 Terasen Gas Inc. Biomethane Application, section 7, Supply in British Columbia, pages 61 – 66; Table 7-1, page 63.

13.1 Please define “bioenergy” as used in section 7 and distinguish it from “biogas” and “biomethane.”

Response:

“Bioenergy” in this context generally refers to any source of energy derived from biological resources.

“Biogas” generally refers to gas composed primarily of methane and carbon dioxide. Biogas is typically derived from anaerobic digestion of organic material.

“Biomethane” is a purified version of biogas. It is almost 100 percent methane and is derived by purifying biogas.

13.2 Are the fuel sources listed in Table 7-1 are the only ones that FEI expects to use under its Biomethane Program? Please discuss.

Response:

Yes. FEI is not currently aware of other sources of energy that could be used in its existing pipeline.

As discussed in the 2010 Biomethane Application, FEI does not currently intend to use any wood-based sources of energy for its biomethane program at this time. FEI understands that wood-based resources can be converted to a combustible gas. However, that gas (generally referred to as syngas), cannot be easily converted to methane at a cost that would be consistent with the present program. There are efforts around the world to convert syngas to methane and FEI will continue to monitor these developments.

13.3 Would FEI seek regulatory approval before using biomethane from a fuel source not discussed in Table 7-1?

Response:

If future sources of fuel require a significant change to the business model or to the current biomethane specification, it is likely that FEI would seek regulatory approval. For example, if wood-waste were considered a different fuel source and the gas specification required FEI to accept gas such as hydrogen, then FEI would seek regulatory approval.

At this time FEI does not anticipate future fuel sources other than wood-waste and that source is not likely to be commercially available anytime within the next few years.

13.4 Please provide any updates FEI has to its assessment of the supply of bioenergy resources in B.C. Please provide time series estimates, as applicable, for any bioenergy resources whose volume is expected to vary over time.

Response:

FEI continues to exclude the potential use of wood-waste in its future supply estimates.

Please refer to the response to BCUC IR 1.53.1 for an update on the supply volumes and an explanation of FEI assumptions.

13.5 Please provide curves for resource cost versus resource volume for each of the bioenergy resources listed in Table 7-1, including, as applicable, costs for transporting the resource to the place of processing.

Response:

FEI does not have this data available, however, FEI can offer some comment.

In general, there is a limited distance which bio-resources can be transported and still be used economically to produce biomethane. For example, cattle manure consists primarily of water and the cost of transporting it can quickly exceed any potential revenue benefits of using it as a feedstock.

This would typically imply that the source of the waste must be reasonably close to the processing (upgrading) location. In addition, the upgrading location must be close to the FEI natural gas system. This would imply that bio-resources should be reasonably close to the FEI system to be economically beneficial to any biomethane project.

13.6 Please list and describe FEI's sources of information for its estimate of bioenergy resources in B.C.

Response:

Please refer to the response to BCUC IR 1.53.2.1.

13.7 Please describe in more detail than is given in section 7 how FEI estimates the total amount of bioenergy available in the province.

Response:

In its 2010 Biomethane Application, FEI derived the total potential at a high level from the data provided in Table 7-1 of the 2010 Biomethane Application.

To estimate Maximum Potential, FEI continues to use a similar methodology to that originally used. However, In 2012 FEI engaged a consultant to assist in validating FEI's original biomethane potential estimates. This study attempted to take into account the relative location of the FEI system. That study is described further in the responses to BCUC IRs 1.53.1 and 1.53.2.

In addition, since the 2010 Biomethane Application, FEI has tracked potential supply by incorporating known prospects into its short-term potential. This provides a more accurate estimate of the available supply on the medium term horizon (next one to five years).

13.8 Please describe each bioenergy source given in Table 7-1, describing its general nature, the technological process needed to render the feedstock into biomethane, and considerations such as energy density and environmental side-effects that are relevant to assessing the merits of each type.

Response:

The table includes five broad categories.

1. Forest Residue: This is generally the remnants in the forest left from standard forestry practices. As described above FEI is not including this energy source because there is currently no commercially available means of converting it to biomethane. Further, the majority of this resource would be located a significant distance from the FEI system, making it an unlikely source of economic feedstock.

2. Agriculture-Food Resources: This category describes residues from food processing and restaurant waste. In general, this resource would be considered a prime source of energy for digester projects as it typically can be converted to biogas relatively easily and the yields (biogas per kg) are relatively high compared to other resources. It is expected that this type of waste will be combined with on-farm waste (cattle manure) to increase biogas yield at both the Dicklands and Seabreeze Projects. Located close to the existing gas load (FEI system) this resource is considered an ideal feedstock by project developers.

3. Municipal Resources: This category describes waste collected from residents in municipalities. It is a combination of any organic fraction of waste collected by municipalities and wastewater sludge. It is looked at in a similar fashion to Agriculture-Food Resources in regard to energy potential, location and economics.

4. Temporary: As described previously, the Mountain Pine Beetle Kill is not considered as a likely source of biogas. Landfills, however, are a good source of biomethane. Typically located close to population, and containing significant organics, they are a good source of energy. The temporary nature of landfills is not considered a serious detriment to future energy potential. Typical landfills will generate gas for decades even if no further waste is added. In addition, as organics are diverted from landfills, that energy is still available. FEI would predict that as organics are diverted from landfills, the potential will decrease there, but increase in another category such as municipal resources or Agriculture-Food resources.

5. Growing Resources: FEI has assumed that much of this resource is located in the Fraser Valley and therefore relatively close to the FEI system and it is therefore viable as a source of biomethane. Again, forest resources are ignored.

13.9 Please describe in detail what criteria are used to include and exclude bioenergy resources in the estimate of resources for biomethane. Is the distinction entirely technological? Are there economic calculations involved in some or all cases? Please provide a discussion for each technology listed in Table 7-1.

Response:

The two primary factors are technology (wood waste vs. organic waste) and location. Please refer to the responses to BCSEA IRs 1.13.1 through 1.13.8.

13.10 Please discuss which of the bioenergy resources listed in Table 7-1 are suitable for use for electricity generation, and discuss any instance where using the resource for electricity generation has a particular advantage over using the resource for biomethane.

Response:

FEI understands that any of these bioenergy resources could be used for electricity generation. Again, based broadly on the two categories of wood-waste and organic waste, the process is different, but achievable.

In the case of wood-waste, syngas can be created which can then be burned in a reciprocating engine attached to a generator.

In the gas of biogas, typically the biogas will be burned directly in a reciprocating engine attached to a generator. In this case, the clean-up requirements are significantly less than for biomethane injection. It is typical, for example at landfills to remove only moisture, siloxanes and hydrogen sulphide. This could result in lower capital costs.

On the other hand, in the case of a landfill, the efficiency of converting biogas to electricity is relatively low compared to biomethane production. FEI has provided commentary on the use of biogas for electricity versus biomethane in its 2010 Application (Section 2.7.1) and in its 2012 Application (Section 5.6).

13.11 To what extent does FEI believe it is or will in the future be competing with electricity generators for bioenergy resources?

Response:

FEI believes that every future biogas project could potentially be developed to generate electricity. In other words, FEI will always compete against electricity generation for bio-energy resources.

Electricity generation will always be a viable option for project developers provided BC Hydro continues to offer long-term power purchase agreements at the current SOP prices.

13.12 Please provide a list (without names, as appropriate) of all the potential projects of each bioenergy type listed in Table 7-1 that FEI is currently pursuing, giving estimated volumes in each case.

Response:

FEI has deliberately slowed its pursuit of future potential projects over the last few months to allow time for clarity in the program. However, the two most prominent projects were mentioned in the 2012 Biomethane Application. They are the City of Vancouver, Delta Landfill and the City of Surrey Organic waste project.

According to the categories, in Table 7-1, these two projects represent landfill and municipal solid waste.

It is too early to make an accurate estimate of volume, but on a preliminary basis, the volume for these two projects is estimated to be as much as 650,000 GJ annually combined.

Other prospects are at a much earlier stage of development and are summarized below. Only prospects that have contacted FEI to have a preliminary discussion are included.

Category	Maximum Projected Annual Volume (GJ)	Comment
Agriculture and Agri-Food	90,000	On-farm (Fraser Valley)
Agriculture and Agri-Food	70,000	On-farm (Fraser Valley)
Agriculture and Agri-Food	70,000	On-farm (Fraser Valley)
Landfill	50,000	
Landfill	75,000	
Landfill	75,000	
Landfill	100,000	
Wastewater Plant	125,000	
Total	***655,000***	

Based on this analysis, the total known prospects have expected maximum contribution of approximately 1,305,000 GJ annually (1.305TJ).

14.0 Topic: Biomethane supply: encouragement of economic development and the creation and retention of jobs

Reference: Exhibit B-1, section 2.1.1, Provincial Government Policy, page 15.

FEI cites the British Columbia energy objective of "[encouraging] economic development and the creation and retention of jobs." (page 15).

14.1 Is FEI aware of any studies that quantitatively assess the potential for biomethane generation and upgrading to businesses, jobs and economic development in B.C.? If so, please provide copies or references.

Response:

FEI is not currently aware of any completed studies that quantitatively assess this potential. FEI is aware that the Biogas Association is currently looking at undertaking a study that would compile a suite of metrics that quantifies the economic, environmental and social benefits related to and extending from biogas development. This study is expected to be completed in March of 2014.

15.0 Topic: Biomethane supply: competition with electricity generation

Reference: Exhibit B-1, sections 5.6 and 5.7, pp. 76 – 79.

15.1 Please provide a list of biomass and biogas energy projects contracted to BC Hydro, citing the sizes of the projects and the amounts of fuel energy used, and indicating which of them is using a fuel source that could otherwise be used for biomethane.

Response:

Based on information available on the BCHydro website, FEI was able to find the following bioenergy related projects. The only project that was clearly a candidate for biomethane was the Fraser Richmond Soil and Fibre Project, which FEI referred to as "Harvest Power" in its application (section 5.7).

Most of these projects are wood-based biomass projects. FEI recognizes wood-based biomass projects are not good candidates for biomethane.

Bioenergy Projects – BC Hydro Community-Based Biomass Power Call

Proponent Name	Project Name	Nearest Community	Annual Energy (GWhr)
Revelstoke Community Energy Corporation	Phase 4 CHP Expansion	Revelstoke	3.6
Corix Utilities Inc.	SFU/UniverCity Community-Based Biomass CHP	Burnaby	9.3
Fraser Richmond Soil and Fibre Ltd.	Fraser Richmond Bioenergy Center	Richmond	4.4
Nations Energy Corporation	Kamloops Biomass Power Plant	Kamloops	33.9
Lytton First Nation	Lytton First Nation Biomass Power Plant	Lytton	33.3

Bioenergy Projects – BC Hydro Bioenergy Phase 2 Call

Proponent Name	Project Name	Nearest Community	Annual Energy (GWhr)
West Fraser Mills Ltd.	Chetwynd Forest Industries Biomass Project	Chetwynd	88
	Fraser Lake Sawmill Biomass Project	Fraser Lake	88
Western BioEnergy Inc.	Merritt Green Energy	Merritt	289
	Fort St. James Green Energy	Fort St. James	289

15.2 Please justify the use of BC Hydro's Standing Offer Program price as the price comparator with biomethane.

Response:

The referenced sections of the Application (Section 5.6 in particular) attempt to evaluate the two main options for making use of a source of raw biogas from the biogas project proponent's perspective –either upgrading to biomethane for injection into the natural gas system or using the biogas energy to produce electricity. The Standing Offer prices are employed for the electricity option since that is an open supply acquisition program of BC Hydro's that is the main option available at this time for a biogas project to obtain a revenue stream from generating electricity.

15.3 Does FEI agree that under the 2007 BC Energy Plan, BC Hydro was given a policy direction by government to develop electricity generation from bioenergy resources? If so, does FEI believe there are limits to that policy direction that are relevant to FEI's current biomethane plans? Please discuss.

Response:

FEI is not aware of any direct limits that have been placed on the policy direction for BC Hydro to develop electricity generation from bioenergy resources. However, FEI is aware that BC Hydro has conducted bioenergy calls for power in the recent past and is not currently pursuing any calls that are specifically targeted at bioenergy sources. Also, FEI is aware that BC Hydro is currently in a situation of excess supply and may be less willing to contract for new supply resources in the next several years.

One purpose of the sections referenced in the question was to demonstrate that, where biogas-to-biomethane or biogas-to-electricity are competing options, the biogas-to-biomethane option will generally produce more useable energy at the end use level and therefore has the potential to better achieve public interest objectives such as reducing greenhouse gas emissions. Another issue to consider is that electricity can be produced from more sources of bioenergy than can biomethane. For example, pine-beetle killed timber and other sources of wood waste can be burned to produce electricity, but are not a source of biogas that can be upgraded to produce biomethane. For these reasons, FEI believes that where the bioenergy source can be used to produce biomethane, this option should be given due consideration and, further, that policies should not unfairly favour using the bioenergy to produce electricity.

15.4 Besides the two projects cited (Harvest Power and Cache Creek Landfill), what other projects is FEI aware of where a developer has chosen to develop electricity generation rather than biomethane? What volumes of biomethane are involved?

Response:

Since the inception of FEI's biomethane program the two projects listed in the question are the only ones that have opted for electricity generation rather than biomethane. Prior to FEI's active involvement in biomethane development there are three other landfills that have established electricity generation projects. These are the Vancouver Landfill in Delta, BC (a 7.4 MW facility), the Capital Regional District's Hartland Landfill near Brentwood Bay (a 1.6 MW facility) and the Cedar Road Landfill near Nanaimo (a 1.3 MW facility). The generating facility at the Vancouver Landfill also provides thermal energy from the waste heat to a nearby greenhouse business.

15.5 What principles should govern whether a bioenergy fuel source is used to make biomethane or to generate electricity?

Response:

FEI believes that the following principles should govern the use of bioenergy:

1. Technological capability to use resource. Resource should be useable by the preferred end-use.
2. Location and proximity of either the gas system or electric system.
3. Most efficient and optimum use of the resource. The total amount of bioenergy in BC is limited and therefore, it should be used as efficiently as possible.
4. Cost to end-users. The price premium should be as low as possible per unit of energy.
5. Environmental Benefits. This principle is related to using the resource efficiently.

In regard to point number 3 above, FEI notes that even in situations where biomethane is used in a cogeneration application, the total efficiency (80% typically) is much higher than that expected if raw biogas is used for electricity generation (in the range of 35%). FEI has briefly discussed this concept in response to CEC IR 1.5.4 and has explored the concept related to efficient use of energy in response to CEC IR 1.28.1 – 1.28.9 and CEC IR 1.29.1

With respect to cost to end users, the use of a bioenergy fuel source to produce biomethane has a much lower cost to end users than if the same bioenergy fuel source is used to produce electricity. This issue is discussed in more depth in CEC IR 1.28.7 and an economic comparison is provided in CEC IR 1.29.3 which details the magnitude of the advantage for a 200 TJ/day project. This assessment concludes that if a developer decides to generate and sell power to BC Hydro instead of selling upgraded gas to FEI, the additional cost is $20.9 million more than the gas option in NPV terms over twenty years.

15.6 Does FEI believe that the Utilities Commission has the legal authority and should provide direction or guidance regarding the use of bioenergy resources for electricity generation versus biomethane?

Response:

FEI does not believe the Commission has the legal authority to require a particular biogas project to produce one or the other of electricity or biomethane. Several of BC Hydro's power acquisition programs such as the Standing Offer Program have been exempted from portions of the UCA by the *Clean Energy Act* so BC Hydro is enabled to contract with biogas-based IPPs without needing BCUC approval.

FEI believes the Commission can establish a regulatory framework for biomethane projects in the context of this proceeding (and others such as the Exemption Inquiry) that establishes a practical basis for having biomethane supply projects approved. Certainty for potential biomethane suppliers in knowing that the program will be in place going forward and that it is subject to a manageable and predictable regulatory process for getting supply arrangements approved will go a long way to stemming the concerns about parties choosing to generate electricity from biogas simply because there is an easier regulatory regime for that option.

15.7 Does FEI believe that government should provide policy direction regarding the use of bioenergy resources for electricity generation versus biomethane? Does FEI believe that section 18 of the *Clean Energy Act* is relevant to this question?

Response:

While government direction, such as under section 18 of the *Clean Energy Act*, may be helpful, FEI does not believe that government direction is necessary regarding the use of bioenergy resources for electricity generation versus biomethane. Producing either biomethane or electricity from biogas can be shown to support government policy and the provincial energy objectives in the *Clean Energy Act*. The main area in which the hurdles for biomethane projects are higher than for biogas projects producing electricity is in the regulatory approvals that must be acquired. Establishing a biomethane program as a "prescribed undertaking" under Section 18 of the *Clean Energy Act* would be one approach that could be used to reduce this barrier. However, approval of FEI's requests in this proceeding would also reduce this barrier.

15.8 Please provide details of any discussions FEI has had with BC Hydro regarding the allocation of bioenergy resources between electricity generation and biomethane?

Response:

FEI has not had any formal discussions with BC Hydro.

However, there are two main issues that have been discussed informally with some BC Hydro staff. The first matter discussed was with respect to making the most efficient use of the bio-resource. The second area is in regard to the SOP. In particular, there have been some discussions to clarify the understanding of the SOP eligibility of a combined heat and power project that notionally uses biomethane.

15.9 Please provide details of any discussions has FEI has had with the FortisBC electricity utility regarding the allocation of bioenergy resources between electricity generation and biomethane?

Response:

FortisBC Inc. (FBC) will purchase power from IPPs and it has a net metering program, but it does not have a formal electricity acquisition program equivalent to the BC Hydro SOP. The current purchase rate for electricity from IPPs is 2.852 cents/kWhr, much lower than the current BC Hydro SOP. In addition, FBC does not currently need more power to meet the needs of its customers.

As a result, FBC does not have a serious interest in developing bioenergy projects or purchasing electricity provided by biogas electricity generation projects. Presumably, if electricity procured at a price lower than the price it pays for power, FEI may consider developing Biogas to electricity projects.

It is, therefore, unlikely that FBC will either purchase bioenergy or develop bioenergy projects at this time or in the near future.

15.10 Does FortisBC's electricity utility currently receive or have plans to receive power generated from bioenergy?

Response:

No. Please refer to the response to BCSEA IR 1.15.9.

15.11 On page 77 (first paragraph), FEI says that the use of a bioenergy resource to generate heat using biomethane is more efficient than using bioenergy to generate heat using electricity, and this is a "societal benefit." What weight should be given to this proposition? Does it also apply for electricity generated from bioenergy that is used for other purposes than heat?

Response:

As discussed in the response to BCSEA IR 1.15.9, FEI believes that the efficient use of bioenergy resources should factor highly in the decision on the final form of energy to develop (biogas/biomethane/end use consumption vs. biogas/electricity/end use consumption).

FEI believes this principle is met best by producing biomethane from the biogas and using the biomethane to meet thermal energy needs at the end use. However, this principle may also be met in a combined heat and power application, where the heat can be used effectively and consistently. It can be shown that if biomethane is used in a CHP application that the approximately 60 percent of the total energy can be delivered to the end user (briefly discussed in response to CEC IR 1.5.4). When compared to the efficiency if raw biogas is used for electricity generation (win the range of 35 percent), using biomethane for CHP is superior to combusting raw biogas for electricity generation. FEI has also discussed the concept related to efficient use of energy in the responses to CEC IRs 1.28.1 – 1.28.9 and CEC IR 1.29.1

In making an evaluation of whether to use biogas to produce electricity or biomethane, it does not matter what energy end uses the biomethane or electricity are used for. The reference to heating in the question and on page 77 of the Application is for convenience of illustration. Producing biomethane will produce more useable end use energy than producing electricity (other than in the exceptional circumstances of high efficiencies being achieved through combined heat and power opportunities) and will therefore displace more conventional energy use, whatever the energy is used for.

15.12 Please provide the source and derivation of the efficiency factors used in Table 5-9.

Response:

FEI used the following facts for a basis of determining efficiency:

Electrical Efficiency: Based upon publicly available data sheet on the Caterpillar Website (please refer to Attachment 15.12), the G3516A+, Generator for Landfill Gas is quoted as having an electrical efficiency of 36.8 percent at 100 percent load assuming biogas is used and has a heating value of 18.6MJ/m3. FEI believes this number is fair as it is neither the lowest nor highest efficiency in this range of generators. For example, the electrical efficiency of other generators made by Caterpillar range as low as 29.6 percent (for the G3512) for biogas.

Upgrader Efficiency: Based on a quotation provided by A.R.C. Technologies (ARC), the provider of the upgrader to the Kelowna Landfill Project, the upgrading plant should be about 90 percent efficient (10 percent parasitic electrical load). ARC guaranteed that 85 percent of the methane would be recovered. By multiplying 85 percent by 90 percent, the overall amount of energy delivered to the system can be estimated at 76 percent of the energy available (85% x 90% = 76.5%).

15.13 FEI cites regulatory factors (“associated uncertainty of the regulatory process” (page 79); and “chose to work with a known and established program” (page 78) to explain instances where a producer chose to develop an electricity generation project rather than a biomethane project. FEI also implies that the price paid to producers affects the choice between electricity generation versus biomethane (“This ultimately translates into a higher cost of energy for end-users. However, from a supplier perspective, the two options are approximately equal.” (page 76). Which factor does FEI believe is the more decisive: price parity or regulatory uncertainty?

Response:

In FEI’s opinion regulatory uncertainty has had a greater impact on proponents choosing electricity generation over biomethane than the prices paid for the electricity or biomethane.

Based on the fact that FEI has been able to negotiate supply contracts within the current BCUC approved maximum biomethane price, it appears that suppliers are satisfied with this price. This includes the two lost projects which FEI described in Section 5.7.

However, it is clear in the review of lost projects, that the uncertainty of the future of FEI's RNG program and expected time to obtain regulatory approval were the key factors in pushing those projects towards electricity generation.

16.0 Topic: Biomethane supply: Ten-year biomethane supply forecast

Reference: Exhibit B-1, sections 5.8 to 5.10, pp. 79 –82; Appendix A, section 7, pp. 61-66.

"FEI has updated its ten-year supply forecast using known prospects as the basis for the next five years." [section 5.8, first paragraph, page 79]

16.1 Please explain the relationship between the "bioenergy" resource supply estimates given in Appendix A, section 7 (excerpted from the Terasen Gas (now FEI) 2010 Biomethane application) and the "biomethane" supply estimate given in section 5.8.

Response:

The "bioenergy" resources indicated in Table 7-1 of the 2010 Biomethane application include all potential resources in BC that could be used for energy in any form. The end uses could include heat from wood based processes or biofuels such as ethanol.

"Biomethane" refers only to the amount of methane derived from the total amount of bioenergy and injected into the FEI system. Therefore, the amount of Biomethane is a fraction of the total amount of bioenergy available in BC.

16.2 Please reconcile the "Total Gross Useable for Bioenergy" amount of 56 PJ per year given in Table 7-1 of Appendix A, section 7 with the "Annual Biomethane" of approximately 5,000,000 GJ given in Figure 5-5 of section 5.8.

Response:

Since the 2010 Biomethane Application, FEI has modified its approach to estimating biomethane supply potential. FEI has provided its method for deriving the volumes of biomethane in Figure 5-5 provided in the responses to BCUC IRs 1.53.1 and 1.53.2.

16.3 Please discuss in more detail the basis for the ten-year biomethane supply forecast. Is it fair to say that the resource discussed in Appendix A is based on a survey of all bioenergy resources potentially available in B.C., while the resources discussed in section 5.8 are based on identified potential projects with identified potential developers?

Response:

The Biomethane potential identified in Section 5.8 of the 2012 Biomethane Application takes into account estimated factors such as the likelihood of success and proximity to the FEI system. It is, therefore, a subset of the total amount of bioenergy in BC.

For additional explanation on the derivation of Figure 5-5, please refer to the responses to BCUC IRs 1.53.1 and 1.53.2.

16.3.1 If so, might the forecast in section 5.8 increase in size, possibly in the near future, in response to factors such as the development of the bioenergy or biomethane industry in B.C.?

16.3.2 In other words, might there be considerably more biomethane resources potentially available that FEI has not identified in section 5.8? Please discuss.

Response:

Except for wood-waste projects, FEI is not convinced that there will be significantly more potential for biomethane within BC. Though the potential may be theoretically greater, FEI has tried to take a more conservative approach to allow for more supply certainty in the case of rising demand.

16.4 In developing the supply forecast in section 5.8, has FEI sought to identify and assess all potentially viable resources from all over B.C.? Please discuss.

Response:

No. FEI did not do an exhaustive survey of all bio-resources in BC. However, FEI believes that the supply forecast is reasonable and should allow for FEI to meet its projected demand.

As indicated previously, FEI has excluded wood waste which is the largest source of bioenergy in BC. For more detail on why wood-waste was excluded, please refer to the response to BCSEA IR 1.13.1.

16.5 Has FEI sought to identify and assess potentially viable resources from outside B.C.? Why or why not?

Response:

No. FEI has not seriously considered potential resources located outside of B.C. At this time, the supply potential in BC appears to be sufficient for the continued biomethane program. In addition, and perhaps more importantly, FEI found that customers identified more strongly with projects done within the province.

16.6 Does the ten-year supply forecast capture all the landfill sites in B.C.? Please discuss.

Response:

Yes. FEI took landfills into consideration. Please also refer to the responses to BCUC IRs 1.53.1 and 1.53.2.

16.7 Does the ten-year supply forecast systematically address the size and viability of the potential resource from agricultural waste in B.C.? Please discuss.

Response:

Yes. The ten-year supply forecast addresses agricultural waste. The report done by CHFour and included as Attachment 53.2.1 in response to BCUC IR 1.53.2.1 addresses agricultural waste availability in BC. FEI has not done further work in classifying or exploring energy potential from agricultural waste.

16.8 For the "total known prospects" and "maximum" categories shown in Figure 5-5, please provide a breakdown according to the resource categories given in Table 7-1 of Appendix A, section 7.

Response:

Please refer to the responses to BCUC IRs 1.53.1 and 1.53.2.

16.9 Please provide curves for resource cost versus resource volume for each of the resource categories that contribute to Figure 5-5, including, as applicable, costs for transporting the resource to the place of processing.

Response:

FEI does not have the data available for this response. However FEI can make some general comments.

Location: FEI expects that transportation costs become prohibitive when the resource is located further than a certain distance from its existing system. For example, FEI has seen distances in the range of 50 to 100km mentioned.

Type of resource: Certain resources have higher amounts of energy per weight and are therefore have greater value even when transporting. For example, in the case of digesters, there is a case to deliver organic food waste (higher energy content) to mix with cattle manure (lower energy content), but not vice versa.

FEI made some consideration of the location of various sources of organic resources based on the report done by CHFour Biogas (Attachment 53.2.1 provided in response to BCUC IR 1.53.2.1). The total amount of resources available for biomethane was adjusted based on location within the province. Only those resources located reasonably within areas where FEI has an existing system were included as potential sources of biomethane.

16.10 How likely is it that resources in the "maximum" category in Figure 5-5 could all become "known prospects" or "negotiated supply" or "current supply" resources in the course of the next few years? Please discuss.

Response:

Provided FEI receives approval for the program, FEI will need to develop the unknown prospects into actual prospects and known prospects into supply agreements in order to meet demand.

The form of that new development has not yet been determined. FEI would not like to provide a guess about future success. Even among known prospects FEI does not have certainty regarding technical feasibility (injection location) or economic feasibility (i.e. would the price be sufficient). These issues require detail analysis that is only practical to conduct as the individual projects are advanced.

17.0 Topic: Biomethane supply: Potential competition with non-pipeline grade biogas products

Reference: Exhibit B-1, sections 5.8 to 5.10, pp. 79 – 82; Appendix A, section 7, pp. 61-66.

17.1 Do other biogas fuels exist, that are not of pipeline grade quality, that have potential for commercial development that might use some of the fuel sources that FEI expects to rely on for the Biomethane Program? Please discuss and quantify to the extent possible.

Response:

FEI has not seriously considered non-pipeline quality gases for injection into the FEI system. At this stage, FEI is focused on developing only those projects which meet the criteria for interchangeability with natural gas.

18.0 Topic: Greenhouse gas (GHG) emissions

Reference: Exhibit B-1; Terasen Gas Inc. (now FEI) 2010 Biomethane Application

FEI's application states, "When used in the place of natural gas, [biomethane] results in the reduction of greenhouse gas ("GHG") emissions. (page 1).

18.1 Please provide a numeric analysis of the lifecycle GHG reductions of using biomethane in the place of natural gas, or point out where this analysis is in the application materials. Please provide this analysis for each technology and resource type that FEI might use under its Bioenergy Program.

Response:

As only the environmental attributes associated with Biomethane are being associated with RNG program, the complete life cycle would misrepresent the GHG emission reductions as the reductions associated with methane destruction would overstate the benefits for the subscriber under the Renewable Natural gas program.

Because the carbon emissions associated with biogas are biogenic as these emission are part of the natural carbon cycle. Consequently, biogas (biomethane) is recognized as a renewable fuel source under the BC *Clean Energy Act*.

> ***"clean or renewable resource"*** *means biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource;"*[2]

In the case of Biomethane, carbon neutral status means that both combustion and lifecycle emissions do not contribute any net greenhouse gases into the atmosphere. The combustion of Biomethane releases biogenic carbon dioxide, which is not additional to the natural carbon cycle. From a lifecycle perspective, the emissions savings from displacing conventional natural gas production far outweigh biomethane's production emissions.

To perform a full lifcecycle analysis for each project would be a costly undertaking as it involves detailed calculations, monitoring and data collection. GHG emission reductions from methane destruction can change dramatically on a project by project based upon their baseline scenario. This is not true for emission reductions from Biomethane where the emission reductions are uniform based on the carbon neutral designation.

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[2] The *Clean Energy Act* is available online at: http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/00_10022_01#section1.

As such, injecting Biomethane into the grid results in avoided emissions from the combustion of natural gas, a fossil fuel that emits 50.3014 kgCO2e/GJ in BC. One gigajoule of 100 percent biomethane will provide a savings of 50.3 kgCO2e when replacing conventional natural gas in BC.

Please refer to Attachment 18.1 for a copy of the report from Offsetters "Biomethane Greenhouse Gas Emissions Review", May 2011.

18.1.1 Please include a discussion of methane emissions from landfill sites and other situations where a biomethane potential feedstock produces methane emissions. Should these emissions be included in the analysis of GHG emission reductions?

Response:

During the life cycle of biomethane, opportunities for emission reductions include the following:

- Methane capture;
- Methane destruction;
- Avoided emissions from fossil fuel extraction and processing; and
- Avoided nitrous oxide emissions.

It is the case that the biogas capturing and upgrading processes in FEI's biomethane program will result in some avoidance of higher-GHG methane releases into the atmosphere. However not all the biogas capture and upgrading to biomethane will cause incremental avoidance of fugitive methane emissions. In some situations, such as at landfills, biogas capture has been already mandated by provincial government regulation, so adding upgrading equipment to convert the raw biogas to biomethane for pipeline injection does not result in additional avoidance of methane emissions. In agricultural situations some emissions would be in the form of methane, but other emissions from farming operations occur from aerobic (rather than anaerobic) decomposition of organic matter, such as for example, when manure is spread on a field, and the resulting emissions are in the form of carbon dioxide rather than methane.

These GHG emission reductions are highly variable, contingent upon the baseline condition and costly to quantify. As such FEI's offering claims the emission reductions for the displacement of natural gas and with a carbon neutral fuel source. In the case of renewable natural gas, Carbon

Neutral status means that both combustion and lifecycle emissions do not contribute any net greenhouse gases into the atmosphere. The combustion of biomethane releases biogenic carbon dioxide, which is not additional to the natural carbon cycle. However, it should be recognized from a lifecycle perspective, the emissions savings from displacing conventional natural gas production far outweigh biomethane's production emissions.

18.2 Please file sections 2.7.2 and 2.7.3 of the Terasen Gas Inc. 2010 Biomethane Application, i.e. "Carbon Neutral Consumption" and "Displacement of Carbon Positive Energy Source," respectively. Are the statements in these sections still valid, and are they relevant to the current application? Please explain.

Response:

Please refer to Attachment 18.2 for the requested excerpts. These sections are still valid. However, Figure 2-7, inadvertently titled Biogenic carbon and Biomethane as not being greenhouse gases. In fact, they are greenhouse gases, but are considered carbon neutral as discussed in sections 2.6 through 2.7.

18.3 Please file Terasen's IR responses in the 2010 Biomethane Application to BCSEA's IR 1.20 (Exhibit B-5 in that application), to BCSEA's IR 2.20 (Exhibit B-7 in that application), and to CEC's 1.1.1 (Exhibit B-6 in that application).

Response:

Please refer to Attachment 18.3 for the requested excerpts.

18.3.1 Are Terasen's responses to those IRs still valid, and are they relevant to the current application? Please explain.

Response:

Yes, FEI's responses to those IRs are still valid as they speak to the carbon neutral designation of Biomethane which is still the case today and is what RNG subscribers are signing up for.

18.4 Please provide an update and discussion on the potential for the Biomethane Program to create GHG reductions that could be marketed as credits or carbon offsets, including who will own any such credits or offsets and whether FEI plans to market such credits or offsets.

Response:

FEI does not have any plans at this time to create carbon offsets from the Biomethane program. The supply contracts have divided the ownership over the environmental attributes between methane capture and the displacement of fossil fuel natural gas. In the case of FEI's user-pay program, the environmental attributes are transferred through to the end user as a result of the premium they are paying for Biomethane. Suppliers on the other hand may monetize their credits should a project be economical to proceed as an offset project and FEI would have right of first refusal of these offsets.

19.0 Topic: Greenhouse gas (GHG) emissions reductions in Renewable Natural Gas (RNG) Offering

Reference: Exhibit B-1, section 3.

19.1 Please provide an accounting of the reductions of GHGs from the RNG offering to date.

Response:

136,500 GJ of Biomethane has been delivered to FEI's pipeline distribution network as of May 2013, which results in a GHG reduction of 6,866 tonnes of CO_2e for the displacement of fossil fuel natural gas that has a carbon intensity of 50.3 kg CO_2e/GJ with carbon neutral Biomethane.

20.0 Topic: Demand for biomethane

Reference: Exhibit B-1, section 4: Demand in B.C., pp. 50 – 62.

20.1 For context, please provide a numeric table showing FEI's forecast demand for natural gas for the time period covered by the biomethane demand forecast, with a break-down of demand according to the rate schedules under which the customers would be served.

Response:

Below is the forecast for Rate Schedules 1, 2 and 3. These customers are eligible to participate in the Biomethane program under Rate Schedules 1B, 2B and 3B. FEI only has forecasted volumes to 2018 as required for the upcoming Revenue Requirement Application.

	2011	2012	2013F	2014F	2015F	2016F	2017F	2018F
Rate 1	68,861,116	69,685,953	69,574,052	69,439,315	69,330,418	69,242,058	69,153,565	69,051,325
Rate 2	23,809,796	24,244,493	24,012,669	24,170,892	24,326,403	24,474,839	24,626,448	24,767,714
Rate 3	16,807,421	16,682,861	17,289,403	17,182,545	17,294,049	17,406,429	17,518,923	17,633,169

20.2 Please provide a tabular breakdown of the demand forecast between the different rate classes under which biomethane would be supplied to customers, showing both numbers of customers and volumes of demand.

Response:

Total Number of Customers for Rate Schedules 1B, 2B, 3B forecasted 2013 - 2017

Moderate / High Demand Scenario	**2013**	**2014**	**2015**	**2016**	**2017**
Rate 1B	6,658	9,547	10,706	13,318	15,248
Rate 2B	89	126	140	173	197
Rate 3B	16	22	25	31	35
Low Demand Scenario	**2013**	**2014**	**2015**	**2016**	**2017**
Rate 1B	4,906	5,658	6,423	6,839	7,261
Rate 2B	65	75	84	89	94
Rate 3B	11	13	15	16	17

FEI does not forecast customer numbers for Rate Schedule 11B. Please refer to the response to BCUC IR 1.38.2 for forecasted volumes under the Moderate, High and Low demand scenarios.

20.3 For the green pricing programs described in section 4.1, please provide the volumetric proportions of "green" versus regular energy used under the green pricing programs.

Response:

Exhibit B-1, Appendix F, page 22 states that in 2010, green pricing sales represented a small proportion of a utility company's overall energy sales. On average, renewable energy sold through green pricing programs in 2010 represented 1.1 percent of total utility electricity sales (on a megawatt-hour basis).

20.4 Please provide the TNS study referenced on page 52 or indicate where it is in the application materials.

Response:

Please refer to Exhibit B-1, Appendices E-3 and E-4 for the results of the TNS RNG Price Final Report and TNS RNG Monitor.

20.5 FEI summarizes the TNS study key findings: "Key findings from the studies demonstrate that the market potential for the current RNG Offering is 27% for a 10% blend, but when taking into consideration current awareness levels; a best case estimate is 3.5% should all customers follow through with their intentions."

20.5.1 Please explain the difference between the "market potential" of 27% and the "best case estimate" of 3.5%.

Response:

27 percent assumes perfect market conditions, which would require a 100 percent familiarity rate and would assume that all customers that indicated they would sign up actually did so. This is the maximum participation rate for a 10 percent premium and 10 percent reduction in GHG. FEI does not consider this to be an achievable potential.

FEI was able to test familiarity rates of the RNG Offering in the most recent TNS survey, Exhibit B-1 Appendix E-3, to determine a more accurate uptake potential. The results show that 13 percent of respondents are familiar with the RNG Offering. As shown in Exhibit B-1, Figure 3-10, applying a 13 percent familiarity rate to a 27 percent market potential results in a 3.5 percent participation rate if all customers that indicated they would sign up did. 3.5 percent is the maximum participation rate for a 10 percent premium and 10 percent reduction in GHG at present awareness levels.

20.5.2 Please discuss the implications of a 27% potential, should it be achieved. Does FEI consider this to be a reasonable eventual goal for the Biomethane Program?

Response:

Please refer to the response to BCSEA IR 1.20.5.1.

FEI does not consider 27 percent potential a reasonable eventual goal for the Biomethane Program.

The implications of a 27 percent participation rate in the residential sector would result in over 196,000 participants, an increase of 4000 percent over 2012 levels. The result on demand would be an annual increase of approximately 1 – 1.5 PJ. This is an unrealistic uptake given the present awareness level of the program, and the available supply to accommodate the demand.

20.6 Please detail how much of the demand forecast is attributable to increased customer uptake through biomethane blends of higher than 10%.

Response:

The demand forecast scenarios do not take into consideration the impact from offering multiple blends.

20.7 Please explain how FEI found and engaged the prospective biomethane customers given in Table 4-3.

Response:

FEI uses various channels to connect with potential RNG customers, outlined in Exihbit B-1, section 3.5. The most effective channel for engaging commercial customers has been direct sales and bill inserts. FEI found and engaged the customers in Table 4-3 using these methods. In the case of Haida Gwaii, FEI responded to a public Request for Expression of Interest.

20.8 Has FEI attempted a systematic survey of potential biomethane customers in B.C.? If so, what were the results? If not, could FEI undertake such a study? Is it possible that the demand for biomethane could be considerably greater than is discussed in section 4 of the application? Please discuss.

Response:

FEI is interpreting systematic survey to mean an extensive survey of every potential biomethane customer in BC. FEI has not attempted to conduct this type of survey due to the time and cost required to undertake such a survey and the limited benefits associated with it. FEI has utilized primary and secondary research as outlined in Exhibit B-1, Section 3 and 4 to determine a high, moderate, and low case scenario for demand of Biomethane. It is possible that the demand for biomethane could be greater than FEI's high demand forecast. However, FEI believes that, at this point in time, given the available information, FEI's three scenarios reflect a conservative assessment of the likely range of potential outcomes for demand of Biomethane in BC.

20.9 Please describe in more detail the WesPac Energy (export market) item shown in Table 4-3 and discussed in section 4.3.1. To where, to whom and how would the fuel be exported?

Response:

WesPac has indicated a desire to purchase renewable natural gas as LNG and pick it up FOB at Tilbury. They would then transport it to regional American markets where it would be used to generate electricity. The RNG portion may qualify towards the markets' RPS standards for electricity generation.

20.10 Does the use of a biomethane blend for natural gas transportation (NGT) help NGT customers to meet mandatory fuel carbon content requirements under the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act* and applicable regulations? Is this relevant in forecasting NGT demand for biomethane?

Response:

Conventional natural gas has a carbon intensity level well below the mandated 10 percent reduction in carbon intensity under the Low Carbon Fuel Requirements regulation. Hence it is not necessary to use Biomethane to meet the requirements. It should also be noted that these regulations apply at the fuel supplier level rather than the end customer.

As a Biomethane blend does not currently help NGT customers meet the mandatory carbon content requirements under the Greenhouse Gas Reduction Regulation, FEI has not utilized this consideration in its forecasting NGT demand for Biomethane.

Please also refer to the response to BCUC IR 1.65.1.

21.0 Topic: Biomethane Program: maximum price of supply

Reference: Exhibit B-1, section 1.1, page 1; section 1.3, pp. 3-4.

FEI says it seeks "adjustments to the maximum price of supply" (page 1); however, the list of approvals sought in section 1.3 does not appear to reference the maximum price of supply.

21.1 Does FEI seek Commission approval for an adjustment to the maximum price of supply? If so, to what level?

Response:

FEI's request for approval for an adjustment to the maximum price is listed in section 1.3, under item 10 as it is one of the criteria under which future supply contracts would be approved. Please also refer to Confidential Appendix J.

FEI has asked that any changes to the maximum price of supply be kept confidential. FEI believes that by keeping the price confidential there is a better opportunity to negotiate future supply contracts for as low a price as possible, thereby benefiting RNG customers.

21.2 Please provide a discussion of why FEI seeks a maximum price of supply and how this would relate to other pricing components of the Biomethane Program, including, the Biomethane Energy Recovery Charge (BERC) and the price of natural gas.

Response:

The Commission imposed a maximum price in its 2010 Biomethane Decision as one of the criteria for approval of biomethane supply contracts. Please also refer to the response to BCSEA IR 1.21.3. FEI is proposing to continue with a maximum price as one of the criteria to facilitate the expedited approval of future supply contracts. FEI's proposed maximum price balances FEI's ability to expand the potential number of supply projects available to FEI in the future, while minimizing the increase in risk of unsold biomethane.

21.3 Is a maximum price of supply relevant to FEI's risk mitigation measures? Please discuss.

Response:

Yes. The original maximum price was put in place to provide a limit on the maximum potential cost of biomethane should it remain unsold. Therefore, the maximum price could be considered to be a risk mitigation measure.

The value of $15.28/GJ was suggested by FEI as a means of selecting projects – conceptually, those projects that could not be successful below the Maximum price should not be pursued. It was based indirectly on the cost of electricity because there was no other reasonable market reference for clean energy.

21.4 Does FEI anticipate that it might seek changes to the maximum price of supply? If so, under what circumstances?

Response:

FEI is currently not expecting to seek additional changes to the Maximum price beyond what was requested in this Application. However, FEI cannot fully predict future market conditions – either supply or demand and therefore, there may be changes to the maximum price in the future.

22.0 Topic: Biomethane Energy Recovery Charge (BERC)

Reference: Exhibit B-1, section 1.3, page 4.

22.1 Please confirm that the BERC is a commodity charge only and does not include other cost elements. If not, please explain.

Response:

The BERC is a commodity charge which is calculated based on the costs associated with acquiring Biomethane supply from the approved Biomethane supply projects. The supply projects comprise two main types, those where FEI purchases pipeline quality Biomethane and those where FEI purchases raw biogas and incurs costs to upgrade the biogas to pipeline quality Biomethane.

22.2 Please provide a prioritized list of the principles that should be considered and applied in setting the BERC.

Response:

FEI does not have a prioritized list. Pursuant to Commission guidelines there are a number of attributes that should be considered when reviewing gas cost deferral account balances and establishing gas cost recovery rates.

Please refer to the responses to BCUC IRs 1.74.1 through 1.74.3.1.

22.3 Should the BERC be the same for all customer classes? Why or why not?

Response:

Yes, under the current model, the BERC rate should be the same for all applicable FEI customer classes. FEI buys pipe quality Biomethane or the raw biogas depending on the supply arrangement on behalf of all customers and recovers those costs through the BERC rate and hence should be the same for all customer classes. The Biomethane sold to customers at the BERC rate replaces a portion of the natural gas sold to customers at the Commodity Cost

Recovery Charge (or commodity rate); the FEI commodity rate is the same for FEI natural gas customers in the Lower Mainland, Inland, and Columbia service areas.

22.4 Why does FEI seek approval of the BERC as a distinct item from the applied-for rate schedules?

Response:

The current process is for FEI to include the review of the BVA and the appropriateness of the BERC rate as part of its routine quarterly gas cost review process with the Commission, and is consistent with how the other FEI gas cost recovery rates are reviewed.

The Commodity Cost Reconciliation Account (CCRA), Midstream Cost Reconciliation Account (MCRA), and BVA, along with the associated Commodity Cost Recovery Charge (commodity rate), Midstream Cost Recovery Charge (midstream rate), and BERC, respectively, are reviewed quarterly. The commodity rate is subject to quarterly adjustment while, under normal circumstances, the midstream and BERC rates are subject to annual adjustment using a January 1 effective date.

22.5 Does FEI anticipate that it might seek changes to the BERC? If so, under what circumstances?

Response:

Please refer to the response to BCSEA IR 1.22.4.

23.0 Topic: Biomethane rates and biomethane blends

Reference: Exhibit B-1,.section 1.1, page 1; Appendices D1 and D2 section 3.8.3 (Proposed Changes to General Terms and Conditions and Other Changes to Rate Schedules 1B, 2B and 3B), pp. 45-46.

FEI seeks approval for continuation of the Biomethane Program with some modifications, including *inter alia*, "Addition of additional blends of Biomethane" (page 1).

23.1 Please provide further discussion of FEI's approach to and plans for additional biomethane blends. Why did FEI choose the structure that it did for offering different biomethane blends to its customers? What alternative blend structures has FEI considered?

Response:

FEI conducted research of other green pricing programs as well as surveyed price points and blend options amongst customers in 2010 and again in 2012. FEI also considered the ability of its billing system and the modifications required to support various options. When FEI launched the biomethane offering in 2011, the previous billing system was only able to provide a modification to the commodity line item on the bill; therefore, Biomethane customers in 2011 saw a blended rate on their bill. FEI had the option when moving over to the new CIS to add an additional line item so now RNG could be seen as a separate line item and provide the customer with more detail.

FEI's research found that popular renewable energy programs allowed customers to purchase "blocks of energy" and the price premium was typically between 10 to 20 percent. Therefore, FEI used this as a guideline for its initial offering and launched with a 10 percent blend option which translated into about a 10 percent premium on the overall bill. A 10 percent premium for a 10 percent reduction in GHG's also showed the most uptake potential in FEI's surveys.

In order to continue to grow interest in the program as well as reach customers that have indicated they would like higher percentage blends of RNG, FEI proposes updating the Biomethane tariff so that additional blends can be introduced. FEI would make available to customers pre-determined amounts such as a 20 percent, 30 percent and 100 percent option. FEI has proposed that this will be offered in 10 percent increments so that it can better be managed from a supply/ demand, billing management and customer communications perspective.

Additionally, Rate Schedule 11B and Rate Schedule 30 allow for bulk sales of Biomethane on or off system for large volume sales.

23.2 Why does Rate Schedule 11B offer no biomethane blend alternatives, when other rate schedules do?

Response:

Rate Schedule 11B was originally created as a mechanism to sell bulk surplus sales of Biomethane. It is an on-system interruptible sales rate that facilitates selling bulk sales of Biomethane through a gas marketer. There are transportation customers, however, that are requesting certain volumes of Biomethane on an ongoing basis. The only way to sell these customers Biomethane is through Rate Schedule 11B and the volume/cost of Biomethane gets deposited in their gas marketer account for their use. Customers that use this mechanism can select a certain volume. Summerhill and Opus for instance, signed up for a certain GJ volume which translated into 10 per cent of their overall gas usage. In this way, the volume of Biomethane they select under Rate Schedule 11B can be a percentage of their overall gas consumption.

Please also refer to the response to BCUC IR 1.75.3 for a description of this process.

23.3 Does FEI believe that offering different biomethane blends to customers will increase or maximize the volume of biomethane supplied to customers? Please discuss.

Response:

FEI believes that offering different biomethane blends will be a way to increase the volumes of biomethane sold to existing customers that have indicated a desire for a higher percentage. It is also a way to promote something new about the program and attract new customers. FEI has received feedback that some customers have not subscribed as they feel the offering is too low a percentage. Additionally, LEED buildings require a higher percentage of renewables to attain certain LEED points, and this would be a way that FEI could reach those commercial customers.

23.4 Should FEI maintain flexibility in its ability to offer different blends to its customers in response to changing circumstances? Please discuss.

Response:

Yes, FEI believes maintaining flexibility to offer different blends allows FEI the ability to efficiently manage the program and respond to customer demand and changing circumstances.

24.0 Topic: Supply cap

Reference: Exhibit B-1, sections 1.1 and 1.3, pages 1, 3 and 4; section 8.

FEI says it seeks approval for continuation of the Biomethane Program with some modifications, including *inter alia*, “An increase in the supply cap from its existing 250,000 GJs.” (page 1); however, the supply cap does not seem to be mentioned in the list of approvals sought, nor does the supply cap appear to be discussed in connection with risk mitigation.

24.1 Please confirm what changes to the supply cap FEI is seeking and whether FEI is seeking Commission approval for such changes in this application.

Response:

FEI has requested an annual supply cap of 3.0 PJ (3,000,000 GJ). The supply cap is one of the criteria under which future biomethane supply contracts would be approved, i.e. any future supply could not exceed the supply cap without further Commission approval. This approval sought is listed in item 10 on pages 4-5 of the Application. Section 6.5.1 of the Application discusses the change in the supply cap that is sought.

24.2 Please discuss why a supply cap is necessary or desirable for the Biomethane Program, providing a prioritized listing of factors that are relevant.

Response:

Because FEI pays a premium for biomethane, the cap provides an upper bound on any potential impact to all customers.

In addition, a supply cap gives a clear indication of the size of available market to potential supply developers. That is, it provides developers some guidance with regard to both the possible size and number of projects that they may choose to pursue.

24.2.1 Is a supply cap relevant to mitigating the risk of over-supply? Please discuss.

Response:

Yes, the supply cap is a limit on the amount of supply that the FEI can contract for without further Commission approval and therefore limits the risk of over-supply. Please refer to the response to BCSEA IR 1.24.1.

24.3 If a supply cap is maintained for the Biomethane Program, when and under what circumstances might FEI apply to have it changed?

Response:

FEI would only seek approval to change the supply cap if the demand exceeded, or was expected to exceed, the proposed cap and the supply potential was available to meet that increase in demand.

25.0 Topic: Marketing plans for the Biomethane Program

Reference: Exhibit B-1, section 3.9, pp. 47 – 49;Appendix F-1, section 1.1.1 Participation Rates in Green Pricing Programs (page 1); Appendix A, sub-appendix C, NTRL Green Power Marketing in the United States: A Status Report (2008 Data).

25.1 What customer uptake and biomethane volume goals, if any, has FEI set for the Biomethane Program for the next five to ten years?

Response:

Please refer to the response to BCUC IR 1.38.2.

25.2 Does FEI consider it practical or desirable for it to achieve "Top 10 Programs" performance, as referenced in the NTRL report and in Appendix F-1, section 1.1.1? Please discuss.

Response:

FEI has projected capture rates of 1 percent, 3 percent and 5 percent. The 5 percent participation rate could achieve a Top 10 Program performance, but is a high case scenario in FEI's analysis. It is feasible and definitely desirable for FEI to achieve Top 10 performance. The principles of FEI's Biomethane program were meant to emulate the top performing programs (e.g., local projects, low cost per month, customer engagement, renewable energy projects, and contribution to the greater good).

Please refer to the response to BCSEA IR 1.20.5.1 for FEI's projected participation rates. While it may be desirable to reach the Top 10 status, it may not be practical from a cost benefit standpoint. FEI's expected participation rate of 3 percent is below the Top 10, but slightly above industry averages.

25.3 Please outline FEI's marketing plans for its Biomethane Program. Are they confined to the initiatives outlined in section 3.9 (Future Expansion of the RNG Offering to Rate Schedules 5, 14A and 16)?

Response:

No, FEI's plans are not confined to the initiatives outlined in section 3.9, which are part of the overall strategy to increase demand and meet the objectives of the Biomethane Program. Please refer to the response to BCUC IR 1.10.1 for a copy of FEI's current marketing plan. In general, FEI intends to launch additional blends as soon as feasible, secure long-term demand prospects and expand the offering to additional Rate Schedules. Once the program continuation and expansion is approved, more specific marketing plans and timelines for implementation will be developed for each of these target areas.

26.0 Topic: Air Miles

Reference: Exhibit B-1, section 3.2.1.1, pages 24 – 25; Appendix E-1, RNG Residential Existing Customer Survey, Q 4.

FEI indicates that it needs "additional tangible benefits" to induce customer participation: "Over seventy percent (a ranking of 3.65 out of 5) of those surveyed indicated that FEI thanking customers with AIR MILES reward miles was a motivation for them to sign up for RNG." (page 24).

26.1 In FEI's view is there an (a) actual or (b) apparent contradiction in offering its customers Air Miles rewards – which would encourage additional air travel and fossil fuel use causing GHG emissions – to market the Biomethane Program, one of whose significant purpose is to reduce GHG emissions?

Response:

The partnership is with AIR MILES for social change (AMSC) that inspires positive social change to benefit the environment. The reach and power of the AIR MILES Reward Program allow us to cost-effectively reward miles aimed at driving large-scale shifts in consumer behavior that benefit the environment. AMSC has been successful in increasing participation rates in other energy efficiency, utility and government offerings in other jurisdictions and can offer a lower participant acquisition cost when compared to other communications channels. Yes it is possible that customers could use AIR MILES for air travel but that does not necessarily mean it is incremental air travel. AIR MILES is just another currency that could be used for air travel that may have been purchased with cash otherwise. Despite the name 'air miles reward program', the air miles program is no longer only a flight-based program. Today, collectors cannot earn air miles from a specific airline (as once was the case). Most collectors today redeem their points for non-flight based rewards. Additionally, AIR MILES has added over 100 'green' rewards to its "My Planet" rewards section.

Please also refer to the responses to BCUC IR 1.14.3 on why AIR MILES is a customer education activity and BCSEA IR 1.26.2 on statistics regarding the proportion of AIR MILES rewards redeemed for air travel.

26.2 What proportion of Air Miles rewards are redeemed for air travel?

Response:

This response discusses information that is commercially sensitive to Air Miles and which FEI is obligated to keep confidential under a non-disclosure agreement. FEI is therefore filing this response confidentially in accordance with the Commission's Practice Directive for Confidential Filings.

26.3 What is the cost to FEI of the Air Miles offering, and what budget does it come from?

Response:

Please refer to the responses to BCUC IRs 1.14.1 and 14.3.1.

26.4 What feedback, if any, has FEI received about its Air Miles offering, apart from what is reported in the customer survey results in this application?

Response:

FEI has not received any additional feedback apart from what is already reported in the customer survey results. The fact that the participation rates went up by 70 percent when the AIR MILES campaign was launched indicates a strong customer interest and motivation to sign up for RNG for such rewards.

26.5 Are there any practical alternatives to Air Miles to induce customers to participate in the Biomethane Program? Please discuss.

Response:

Yes, there are practical alternatives, but the AIR MILES program has been effective in increasing participation, is cost effective when compared to other media channels, has rich targeting capabilities and analytics to offer customized promotions, and is one of Canada's top influential brands. FEI has an integrated marketing approach as discussed in the response to BCUC IR 1.15.3 and looks at cost-effective ways to increase participation. To create awareness and stimulate participation, FEI needs to have a diverse set of motivators in the market place, such as economic motivators (through AIR MILES) and social motivators (through customer engagement media campaigns to reach out to a broad audience).

Please also refer to the response to BCUC IR 1.14.3 on how AIR MILES is helping FEI to create awareness and stimulate participation.

27.0 Topic: Long-term goals for the Biomethane Program

Reference: Exhibit B-1

27.1 Does FEI intend to maximize the amount of biomethane it provides through the Biomethane Program?

Response:

FEI's goal is to be able to develop as much biomethane as feasible for delivery to its pipeline network and meet customer demand for renewable natural gas, provide the best use of a renewable resource and contribute to GHG reductions in BC. FEI believes this to be in the range of 3 to 5 PJs. FEI is currently limited by the existing program structure and the need to tie supply with demand.

FEI believes the ideal way to structure the program would be to have a user-pay program backstopped by a renewable portfolio allowance as discussed in the response to BCUC IR 1.49.7, that would be similar to the MCRA proposal included in this Application. For example, FEI would be allowed to develop RNG for the user pay market and any unsold Biomethane would be absorbed by all customers if FEI is unable to sell through its existing channels at the BERC rate. This would allow FEI to fully pursue supply projects, without having to tie customer user-pay demand to projects. This serves customers that want to select a higher percentage blend of Biomethane and large industrial customers such as UBC, while at the same time maximizing the development of Biomethane and GHG emission reductions in BC.

Please also refer to the response to BCUC IR 1.36.2.

27.2 What does FEI consider to be the ultimate potential for increased biomethane supply and displacement of natural gas in its system in the long term? What factors limit this potential?

Response:

Please refer to the response to BCSEA IR 1.27.1.

27.3 Would FEI consider changing the current voluntary Biomethane Program to a standard biomethane blend for all customers? Please discuss the circumstances that would need to exist for this to be viable or desirable.

Response:

Please refer to the response to BCSEA IR 1.27.1.

28.0 Topic: Under-supply risk; purchase of carbon offsets

Reference: Exhibit B-1, section 1.3, Approvals Sought, #6: continuation of FEI's ability to purchase carbon offsets (page 4); section 8.2.1, Under-Supply Risk, page 111.

FEI seeks approval to continue its ability to purchase carbon offsets, to manage the risk of under-supply of biomethane: "This measure would be used to make up any shortfalls on a short-term basis." (page 111).

28.1 Does "on a short-term basis" in the above sentence refer to the shortfall or to the purchase of offsets? Is FEI proposing that any purchase of carbon offsets would be regarded as a permanent and final substitute for instances of a short-term biomethane shortfall?

Response:

It is not FEI's intent to permanently replace biomethane supply with offsets. Rather, in a given year, if there is a supply disruption, this mechanism would be utilized to maintain the GHG integrity of the program so FEI would not have to remove customers from the program as a result of a temporary outage.

28.2 What types of carbon offset are available and what type would FEI purchase, in the event that FEI had to purchase carbon offsets?

Response:

Should FEI not achieve its expected volume of biomethane for a given period, FEI will purchase offsets to ensure that renewable natural gas customers will continue to receive a 10 percent savings in GHG emissions from combustion. FEI worked with its carbon consultant agency, Offsetters, to develop criteria and a process in the event FEI had to purchase carbon offsets as a risk mitigation strategy. A summary of this strategy is provided below:

Projects

- Any credits necessary will be sourced from North American Landfill Gas projects, with a preference for Canadian projects where possible.
- All credits will be sourced from Verified Carbon Standard (VCS) or Climate Action Reserve rated projects.

- Carbon credits from existing supply projects should be avoided because they are the current providers of biomethane/renewable natural gas and it presents the potential for double counting.
- Where possible, Offsetters will source methane destruction projects within FEI's service territory.
- Where BC and Canadian-based projects are not possible, Offsetters will seek out US-based methane destruction project credits.

Timing

- FEI will report any biomethane shortfalls to Offsetters on a quarterly basis, and Offsetters will secure those equivalent credits in the following quarter.
- FEI will purchase any offsets before the end of any calendar year.

Pricing

Offsetters will provide carbon credits at the following thresholds and prices:

Tonnes	Price per tonne
1-1,000 tonnes	$15
1,001 to 2,000 tonnes	$14
2,001 to 5,000 tonnes	$13
5,001 to 15,000 tonnes	$12

The current price premium for Biomethane is $7.23 GJ, which translates into $144 tonne / CO2e. Therefore, FEI is confident that purchasing offsets should not adversely increase the BERC rate. All costs will be tracked in the BVA and be reported to the Commission in the quarterly gas cost report. As customers prefer a renewable energy program, FEI will update customers as to the status of the program through its website or renewable natural gas newsletter or other communication as necessary.

FEI has committed to purchasing any offsets from the Pacific Carbon Trust (PCT) only for the biomethane volume shortfall that would have been associated with FEI customers that are Public Sector Organizations as these organizations are required to purchase carbon offsets through the PCT. Should PCT cease to exist, FEI will discuss with the Climate Action Secretariat how best to proceed. At this time, FEI would utilize Offsetters for any other purchases.

28.3 What assurance does FEI have that carbon offset unit costs would not exceed the unit revenues from biomethane customers? In such a case, who would absorb the shortfall?

Response:

Please refer to the response to BCSEA IR 1.28.2.

28.4 Please discuss how FEI would ensure the validity and third party verification of any carbon offset purchased.

Response:

Please refer to the response to BCSEA IR 1.28.2.

28.5 Does FEI intend to rely on the Pacific Carbon Trust (PCT) to source offsets? If so, and if the PCT ceases operations, how will FEI acquire carbon offsets?

Response:

Please refer to the response to BCSEA IR 1.28.2.

28.6 How will FEI report on acquisitions of carbon offsets to the Commission? to its customers?

Response:

Please refer to the response to BCSEA IR 1.28.2.

28.7 Please discuss in more detail what circumstances might cause FEI to find that there was a "structural deficit," such that FEI would need to remove biomethane customers from the program?

Response:

A structural deficit could occur if the Biomethane program is fully subscribed and a Biomethane supply project fails to deliver its expected volumes. FEI intends to bank some supply to help mitigate this risk, but should the bank be used up and a project fails to ramp up to its expected volumes or another project does not replace these volumes, then FEI could be in a position where supply does not meet demand and customers would need to be removed from the program as FEI could not meet demand.

FEI believes that removal of customers from the Biomethane programi would be viewed negatively; therefore, carbon offsets could be used to bridge the gap temporarily while another project comes online or supply is made up in another way (e.g. – other producers are able to ramp up supply). FEI believes this can be managed at the program level and does not require Commission approval.

28.7.1 Does FEI believe that removal of customers from the Biomethane Program would be detrimental to the Biomethane Program or customer relations?

Response:

Please refer to the response to BCSEA IR 1.28.7.

28.7.2 Should the Commission have a role in determining whether there is a structural deficit in the supply of biomethane warranting removal of customers from the Biomethane Program?

Response:

Please refer to the response to BCSEA IR 1. 28.7.

29.0 Topic: Over-supply risk

Reference: Exhibit B-1, section 8.2.2, Over-Supply Risk, pp. 112 – 114.

29.1 What is the likelihood of an over-supply of biomethane, and what quantities of oversupply does FEI anticipate?

Response:

FEI does not anticipate an over-supply of biomethane. FEI has outlined risk-mitigation tools in Exhibit B-1, Section 8 for both over-supply and under-supply scenarios.

29.2 In what circumstances might the banking of biomethane due to oversupply affect FEI's regular acquisition of natural gas? Might this cause costs to FEI or its customers?

Response:

As the biomethane is consumed once it is injected at the supply point, the banking of biomethane does not affect FEI's regular acquisition of natural gas. This is because any banking is notional and not actually available to be used by FEI as a cumulative volume on any specific day, like that of a storage facility. Furthermore, at this point in time, the biomethane volumes are very small and not material enough for FEI to consider shedding other supply resources to meet core customer load requirements.

In the future, should the biomethane volumes become material in terms of FEI's total resource portfolio, FEI would consider shedding some regular gas supply resources in order to minimize costs for customers. The biomethane supply volumes would have to be consistent and reliable on a daily basis, particularly during peak winter demand periods, before any portfolio changes would be made.

29.3 Regarding the notional banking of biomethane for future sale (page 112), how would this be accounted for and verified? Should the Commission have a role in overseeing the banking of biomethane?

Response:

Biomethane supply and sales, in terms of both volumes and dollars, are tracked in the BVA. FEI ensures that no more Biomethane is sold than is injected into its system and volumes are reconciled on a monthly basis. This is a similar process for managing nominations for industrial transport customers and matching actual consumption with supply.

The monthly activity and balances within the BVA are filed quarterly with the Commission as part of the Company's quarterly gas cost reports.

FEI believes the banking of Biomethane can be managed within the program through long term customer contract demand, supply forecasts, and risk mitigation measures for selling off any surpluses taking into account demand and market conditions. However, should FEI seek to recover any costs through the MCRA for excess banked volumes, FEI would seek Commission approval of such an activity.

29.4 Please discuss in more detail the agreement with WesPac and how it might mitigate an oversupply of biomethane?

Response:

WesPac has provided FEI with an LOI indicating they are interested in procuring large amounts of biomethane. Their potential markets could take even more than they have indicated; therefore, FEI sees this as another assurance that there is a market to sell biomethane. WesPac's business plans are not contingent on FEI providing biomethane. Rather, FEI's provision of biomethane would be an added bonus to their business plans as a way for their natural gas electricity generation to contribute to customers' RPS requirements.

At this time, WesPac and FEI have not entered into any firm agreements for the sale of biomethane on an ongoing or interruptible basis.

29.4.1 Does FEI have any obligation to provide certain amounts of biomethane to WesPac?

Response:

No. Please refer to the response to BCSEA IR 1.29.4.

29.4.2 Is WesPac content to be a buyer of last resort? Would it be reliable in that role? Is there a price premium for this?

Response:

Please refer to the response to BCSEA IR 1.29.4.

29.5 Is FEI saying that there is a market for bioenergy that can reliably absorb an oversupply of biomethane in FEI's system?

Response:

FEI believes there is the potential for off-system sales of bioenergy. Given the multiple markets identified and LOI already secured from one potential large customer, FEI believes a biomethane shortfall is the more likely outcome in the long term.

29.6 Does or will some proportion of FEI's biomethane customers have an obligation to receive biomethane? If so, to what extent will that mitigate the risk of oversupply?

Response:

FEI's current business model has been designed to be flexible so as to meet the varying demands of its customers. Rate Schedules 1B-3B offers Biomethane to customers on a voluntary basis and Rate Schedules 11B and 30 allow the ability to sell bulk sales of Biomethane on a daily, monthly or annual basis. For emerging markets such as UBC, FEI intends to develop long-term take or pay agreements. All of these selling mechanisms contribute to FEI mitigating the risk of oversupply.

Attachment 1.2

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BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER

TELEPHONE: (604) 660-4700
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DRAFT ORDER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

FortisBC Energy Inc. Biomethane Service Offering: Post Implementation Report and Application for Approval of the Continuation and Modification of the Biomethane Program on a Permanent Basis

BEFORE:

(Date)

WHEREAS:

A. On December 19, 2012, FortisBC Energy Inc. (FEI) filed an application (the Application) to the British Columbia Utilities Commission (the Commission) which constitutes FEI's Post-Implementation Report on the Biomethane Program in compliance with Commission Order No. G-194-10. The Application seeks approvals for the continuation of the Biomethane Program on a permanent basis with certain modifications.

B. In the Application, FEI seeks the following approvals pursuant to sections 59 to 61 of the Utilities Commission Act (the Act):

- Continuation of Rate Schedules 1B, 2B and 3B, and amendments to the same;
- Continuation of Section 28 and related definitions of FEI's General Terms and Conditions (GT&Cs), and amendments to the same;
- Continuation of Rate Schedules 11B and 30 as part of FEI's Biomethane Program;
- Continuation of the cost allocations and accounting treatment for the costs associated with the Biomethane Program, including the continuation of the Biomethane Variance Account, the quarterly reporting process and the Biomethane Energy Recovery Charge (BERC) rate setting mechanism;

- The resetting of the BERC rate at $12.001/GJ to be effective at the start of the first quarter after the Commission's Decision in this Application;
- Continuation of FEI's ability to 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 BERC and the Commodity Cost Recovery Charge in effect at that time;
- Approval of the recovery of costs in the Biomethane Variance Account through the Midstream Cost Recovery Account as set out in Section 8 of the Application;

C. FEI seeks acceptance, pursuant to section 71 of the Act, of four Biomethane Purchase Agreements:

- Earth Renu Energy Corp.
- Greater Vancouver Sewerage and Drainage District
- Seabreeze Farm Ltd.
- Dicklands Farms

D. FEI seeks acceptance, pursuant to section 44.2 of the Act, of the capital costs related to the facilities required for the four biomethane supply projects as described in Section 7 of the Application.

E. FEI seeks approval that future supply contracts for the purchase of biogas or biomethane filed with the Commission that meet the criteria described in Section 6 of the Application, including the proposed increase in the supply cap and confidential maximum price, meet the filing requirements in sections 71(1)(a) and 71(1)(b) of the Act.

F. On February 28, 2013, the Commission issued Order G-29-13 and the accompanying Reasons for Decision in regard to FortisBC Energy Inc.'s 2012 Biomethane Application. Directive 2 of the Order stated that biomethane third-party suppliers regulatory review would be heard in separate Streamlined Review Processes.

G. On May 6, 2013, the Commission issued Order G-70-13 in the Biomethane Third-Party Suppliers Regulatory Process, accepting the capital expenditures described in section 7 of the Application related to the interconnection facilities required for the Dicklands, Seabreeze and Earth Renu Biomethane supply projects, and approving the respective Biomethane Purchase Agreements as rates schedules for the proposed biomethane supply service and rates.

H. The Commission has reviewed the Application and concludes that the requested changes as outlined in the Application should be approved.

NOW THEREFORE, the Commission orders as follows:

1. Pursuant to Sections 59 to 61 of the Act, the Commission approves:

    - The continuation and proposed amendments to Rate Schedules 1B, 2B and 3B as described in the Application.
    - The continuation and amendments to FEI's GT&Cs as described in the Application.
    - The continuation of Rate Schedules 11B and 30.
    - The cost allocations and accounting treatment for the costs associated with the continuation and modification of the Biomethane Program requested by FEI and described in the Application.
    - The BERC rate of $12.001/GJ to be effective at the start of the first quarter after the Commission's Decision in this Application.
    - The continuation of FEI's ability to 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 BERC and the Commodity Cost Recovery Charge in effect at that time.
    - Approval of the recovery of costs in the Biomethane Variance Account through the MCRA, subject to an application to the Commission, as set out in Section 8 of the Application.

2. The Commission will accept, subject to timely filing, the revised tariff pages for the amended Rate Schedules 1B, 2B and 3B, and the amendments to FEI's General Terms and Conditions, in accordance with this Order.

3. Future supply contracts for the purchase of biogas or biomethane filed with the Commission that meet the criteria described in Section 6 and outlined below, meet the filing requirements in sections 71(1)(a) and 71(1)(b) of the Act:

    - The supply contract is at least 10 years in length
    - FEI has, by agreement, retained final control over injection location
    - FEI is satisfied that the selected upgrader is sufficiently proven
    - FEI has, by agreement, reserved the right to refuse gas if customer safety or asset integrity is at stake

- The partner is a municipality, regional district or other public authority, or is a private party with a track record in dealings with FEI or that posts security to reduce the risk of stranding
- The total production of biomethane for all projects undertaken does not exceed an annual purchase of 3 PJ
- The maximum price for delivered biomethane on the system is below maximum price set out in Confidential Appendix J of the Application

DATED at the City of Vancouver, In the Province of British Columbia, this day of <MONTH>, 20XX.

BY ORDER

Attachment 2.2

(Provided in electronic format only due to
document size and in order to conserve paper)

Biogas to Biomethane Upgrading for Injection into the Natural Gas Distribution System

June 2009

Project Manager: Enbridge Gas Distribution Inc.

Project Participants: GazMetro LP, Terasen Gas Inc., TransCanada Pipelines Ltd., Union Gas Ltd

ENBRIDGE

Legal Notice

Abstract

This report addresses in some detail gas quality concerns and biogas upgrading plant design. Gas sampling procedures and gas analysis data for biogas, biomethane, and natural gas from existing sites are presented. Statistical analysis is completed on the gas analysis data to determine the probability that natural gas and biomethane streams will meet tariff requirements. The probability that trace contaminants that are present in biomethane but not in natural gas, or present in biomethane in greater concentration than in natural gas, is below acceptable concentration limits based on published exposure limits is also studied. The impact of input biogas quality on output biomethane quality is analyzed for the sites where gas sampling occurred. Enumeration and identification of biologicals (total live, total live plus dead, and spores) is discussed. Interchangeability analysis is completed based on historical gas supply and potential future gas supply. A biomethane decision making process is introduced. Biogas upgrading plant designs are presented and financially analyzed for four theoretical plant designs. Finally, biomethane quality monitoring practices are reviewed.

Executive Summary

Biogas, a renewable gas comprised primarily of 40-70% methane and 30-60% carbon dioxide, is produced during the anaerobic digestion of organic material. The capture and utilization of biogas presents an opportunity to avoid the release of methane that would otherwise be released into the atmosphere as a greenhouse gas and to supplement natural gas supplies.

Biogas can be upgraded to biomethane (or pipeline quality gas) by removal of carbon dioxide and the trace contaminants. Biomethane can be directly injected into the natural gas system or blended with natural gas or propane prior to injection to increase the heating value.

This project addresses in some detail gas quality concerns and biogas upgrading plant design for the purposes of injection, and was guided by the following principles:

- Maintain customer and gas utility personnel safety
- Ensure safe and reliable performance of end use equipment
- Ensure pipeline assets are not negatively impacted

Gas samples (biogas and/or biomethane) were collected at one anaerobic digester, four landfill sites, and two wastewater treatment plants. Natural gas samples were collected from three utilities within Canada.

Gas samples were analyzed for major components, sulphur, siloxanes, extended hydrocarbons, mercury, metals, halocarbons, ammonia, VOCs/SVOCs, PCBs, Pesticides, and Ketones/Aldehydes. Biological analysis was completed on biomethane and natural gas streams for live bacteria, total bacteria, and spores.

Results of lab analysis of the gas samples were statistically analyzed. Natural gas and biomethane lab analysis results were compared to pipeline tariff criteria as defined by the gas quality guidelines in the TransCanada mainline tariff. Under the stated assumptions, the process means of the pipeline tariff criteria of only one landfill met pipeline quality upper and/or lower limits with less than 95% probability. In practice, this site employs blending with natural gas to meet pipeline quality criteria. Under the stated assumptions, the process means of the pipeline tariff criteria of all of the other sites met pipeline quality upper and/or lower limits with greater than 95% probability

Statistical analysis was also completed on trace contaminants that were:

- Found in biomethane samples but not in natural gas samples
- Found in biomethane samples in equal or greater concentration than in natural gas samples

Acceptable concentration levels for trace contaminants were based on published exposure limits. However, there were no found exposure limits for two of the trace

species that meet the above criteria, butanal and p-Isopropyltoluene. For all other contaminants that met the above criteria, and the assumptions employed, it is greater than or equal to 99.92% probable that the process mean of the concentration levels of the contaminants will not exceed referenced exposure limits.

Observations were made on the impact of biogas quality on biomethane quality at upgrading sites visited via boxplots of pipeline quality gas properties/components. The clean up processes appear to be sensitive to fluctuations in gross heating value, Wobbe index, and total inerts. From the boxplots, it could also be interpreted that the clean up processes were able to handle a wide range of input concentrations with out compromising output biomethane quality for hydrogen sulphide, total sulphur, and carbon dioxide. The gross heating value and Wobbe Index of the biomethane appear to be site dependant.

Biological analysis was carried out on biomethane and natural gas streams. Total Live Bacteria was completed using MPN, and resulted in biomethane results ranging from no growth detected to 1.25E+03/100scf, and from no growth detected to 5.46E+05/100scf in the natural gas samples. Total Bacteria (live plus dead) via qPCR resulted in 2.46E+04/100scf to 2.22E+07/100scf in the biomethane samples, and 6.68E+05/100scf to 7.39E+06/100scf in the natural gas samples. Total acid producing bacteria, total iron-oxidizing bacteria, and total sulphate-reducing bacteria are also quantified. Sulfate-reducing bacteria were below the detection limit in all of the samples. Identification of types of bacteria included typical environmental isolates, and isolates associated with the human body. Aerobic spores were found in one of the natural gas samples at a quantity of 1.79E+03/100scf. Spores were found in biomethane samples from one landfill site and one wastewater treatment plant, ranging from below detection limit to 1.21E+04/100scf.

Biologicals in biomethane can be minimized by implementation of different techniques, including pasteurization of biomass, drying of biomethane, and filtering of biomethane.

Interchangeability analysis of biomethane from four existing sites with historical natural gas supplies within Enbridge's franchise indicated that only one supply would require blending of biomethane with natural gas or propane to ensure good combustion performance of end-use equipment. This one site does employ blending prior to injection. All other sites met interchangeability criteria without blending. Interchangeability of the same four biomethane supplies with potential future supplies, 100 % shale gas and 100% liquefied natural gas, indicated that blending would be required for three of the four biomethane supplies studied. One site did not require blending to meet interchangeability criteria. Limits were set on trace contaminants that would either cause corrosion to pipelines, or negatively impact end-use equipment. A decision making tree allows for the optimization of biomethane supplies while ensuring that the guiding principles of this project are upheld.

Four theoretical process flow designs for biogas upgrading to biomethane were completed. All four scenarios are based on different biogas compositions, resulting in different equipment requirements. The first scenario was for an anaerobic digester which processes source separated organics and produces and average biogas flow rate of 1,375 Nm^3/h, at an average of 59.9% methane. The estimated capital investment and annual operating expenditure required were $4.1M and $799,000 respectively, resulting in an NPV of $2.5M and an IRR of 13%. The second scenario was for a landfill which produces an average biogas flow rate of 11,792 Nm^3/h, at an average of 59.3% methane. The estimated capital investment and annual operating expenditure required were $11.8M and $2.6M respectively, resulting in an NPV of $71M and an IRR of 58%. The third scenario was for an anaerobic digester which processes clean organics which produces an average biogas flow rate of 236 Nm^3/h, at an average of 62.1% methane. Due to the low volume, this case was chosen as a scenario to evaluate the use of biomethane as vehicle fuel. The estimated capital investment and annual operating expenditure required were $2.5M and $309,000 respectively, resulting in an NPV of $1.7M and an IRR of 14%. The fourth scenario was a wastewater treatment plant which produces an average biogas flow rate of 2,360 Nm^3/h, at an average of 57.8% methane. The estimated capital investment and annual operating expenditure required were $4.2M and $669,000 respectively, resulting in an NPV of $12M and an IRR of 33%. Sensitivity analysis of NPV and IRR was performed to determine the effects of ±25% change in required capital expenditure, ±25% change in annual operating expenditure, changes in biomethane sales price, and biogas purchase price for all four scenarios.

Utilities accepting biomethane into their natural gas distribution or transmission systems have typically chosen gas quality monitoring equipment on a case by case basis, depending upon; volume of biomethane to be injected, maximum volume percentage of biomethane in the natural gas stream, the sensitivity of end use equipment in the area surrounding the injection point, and the utilities comfort level with biomethane. Biomethane quality monitoring systems may be simple systems that monitor flow, specific gravity, and dew point. Alternatively, biomethane quality monitoring systems may be more complex systems that include flow meters, gas chromatographs, electro-chemical sensors, and dew point monitors. Periodic sampling and offline analysis of trace contaminants can also be performed, specifically for trace contaminants that require a lower detection limit than what is possible utilizing online monitoring.

The study demonstrates that biomethane can be successfully accommodated within existing distribution assets.

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List of Acronyms

AD – Anaerobic Digestion
BG – Biogas
BM – Biomethane
LF – Landfill
LFG – Landfill Gas
MIC – Microbially Induced Corrosion
NG – Natural Gas
SSO – Source Separated Organics
SVOC – Semi-Volatile Organic Compound
VOC – Volatile Organic Compound
WWTP – Wastewater Treatment Plant

1.0 Introduction

Biogas, a renewable gas comprised primarily of 40-70% methane and 30-60% carbon dioxide, is produced during the anaerobic digestion (AD) of organic material. AD is the breakdown of organic material in an oxygen free environment. This process occurs naturally in landfills, and also in man made anaerobic digesters. Anaerobic digesters can be found at a number of wastewater treatment plants, farms, industrial sites, and municipalities for the treatment of source separated organics (SSO). The capture and utilization of biogas presents an opportunity to avoid the release of methane that would otherwise be released into the atmosphere as a greenhouse gas and supplement natural gas supplies.

Biogas can be upgraded to biomethane (or pipeline quality gas) by removal of carbon dioxide and the trace contaminants. Biomethane can be directly injected or blended with natural gas or propane prior to injection into the natural gas system. Biomethane injection facilities have been in existence in Europe and North America for over two decades.[1] A list of biomethane injection sites in North America currently known to Enbridge is included in Appendix A. The lack of sufficient public data on biomethane has led to concerns regarding the safety of the use of biomethane for end use consumers, affects on pipeline assets, and affects on performance and asset life of end use equipment. This report addresses each of these concerns in some detail.

Biomethane injection is not only an environmental opportunity, but also a stand-alone business opportunity. The economic viability of biomethane injection as a business opportunity is also examined in this report through four specific biomethane production scenarios.

[1] KIWA, "Biogas Injection: Current Practices and Final Recommendations,' March 2009

1.1 Project Objectives

The objectives of this project are to address gas quality concerns and develop theoretical biogas upgrading plant designs for analysis. This project is guided by the following principles:

- Maintain customer and gas utility personnel safety
- Ensure safe and reliable performance of end use equipment
- Ensure pipeline assets are not negatively impacted

A high level roadmap which presents areas that may be addressed when undertaking a biogas upgrading project opportunity is shown in Figure 1. The business model aspect of the roadmap is dependant upon the parties involved in the project opportunity, and their respective agreements.

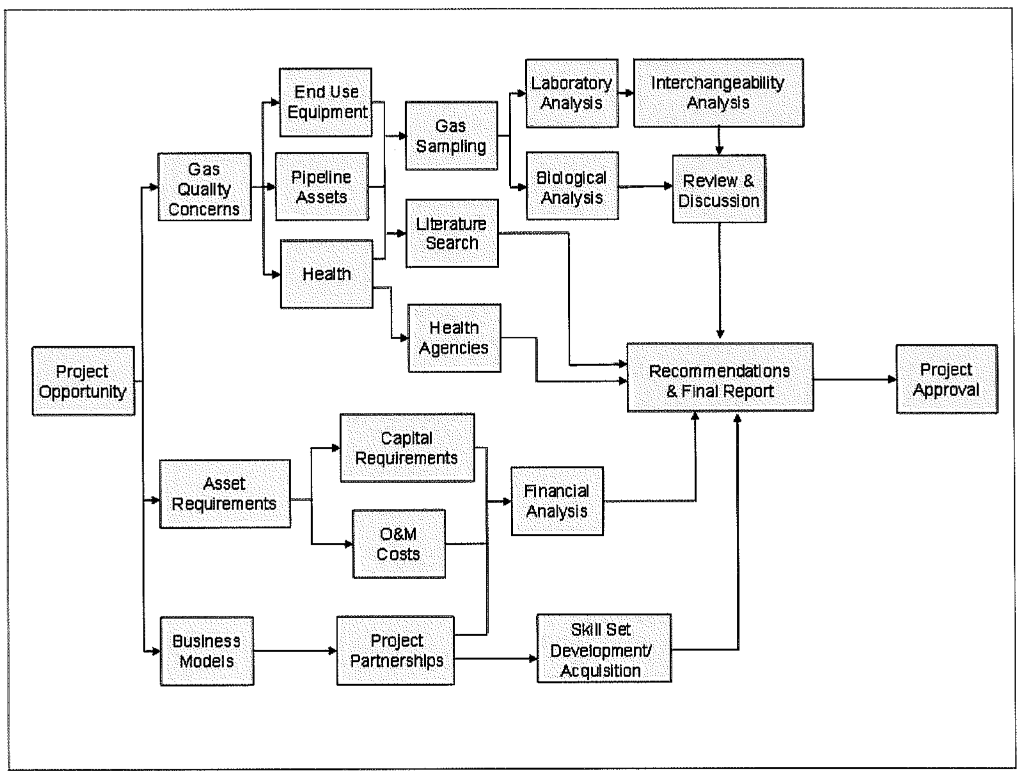

Figure 1 - Biogas Opportunity Roadmap

1.2 Scope of Work

The scope of work in order to complete project objectives is as follows:

- Address Gas Quality
  - Gas sampling and lab analysis from existing biomethane injection facilities, biogas facilities, and natural gas streams
  - Comparison of natural gas and biomethane composition to upper and or lower limits as defined by tariffs and health and safety guidelines
  - Assess performance of biogas upgrading to biomethane for different upgrading processes
  - Biological testing and identification of major species
  - Assess interchangeability of biomethane from existing sites with historical natural gas supply and potential future gas supplies
  - Define a decision making process for biomethane quality requirements for injection into the natural gas distribution or transmission system

- Asset Requirements
  - Complete theoretical biogas upgrading plant designs for four streams
    - Biogas from AD of SSO
    - Landfill Gas
    - Biogas from AD of "Clean" Organics
    - Biogas from Wastewater Treatment Plant
  - Determine required capital expenditures and annual operating costs for the four theoretical biogas upgrading plants
  - Assess financial viability of the four theoretical biogas upgrading plants
  - Complete sensitivity analysis on key inputs to financial model for four theoretical biogas upgrading plants

2.0 Biomethane Composition

Gas composition is directly tied to the three primary areas of concern:

- safety of the use of biomethane for end use consumers and gas utility personnel
- affects on pipeline assets
- affects on performance and asset life of end use equipment

Gas quality guidelines must be developed to address these areas of concern.

2.1 Existing Biomethane Specifications

Existing biomethane injection sites must adhere to gas quality requirements. These biomethane gas quality specifications are typically documented nationally or through local tariffs. In 2006, Marcogaz published a report entitled 'Final Recommendation: Injection of Gases from Non-Conventional Sources into Gas Networks,'[2] documenting existing European specifications (among other things). In 2009, KIWA Gas Technology published a report, commissioned by GERG (the European Gas Research Group), entitled 'Biogas Injection: Current Practices and Final Recommendations,'[1] where the issue of biomethane specification was also addressed. This report is included as Appendix B.

As the Marcogaz and KIWA reports demonstrate, existing biomethane specifications differ from country to country. From discussions within industry, it is also apparent that gas quality requirements differ from tariff to tariff, resulting in different biomethane gas quality requirements. However, specifications are commonly provided for:

- Heating Value
- Carbon Dioxide
- Total Inerts
- Total Sulphur
- Hydrogen Sulphide
- Mercaptan
- Oxygen
- Water
- Wobbe Index
- Relative Density
- Impurities

In select specification, such as France and the Netherlands[2], specifications may also be provided for:

[2] Marcogaz, 'Final recommendation: Injection of Gases from Non-Conventional Sources into Gas Networks,' December 1, 2006

- Halogenated Compounds or Halocarbons
- Siloxanes
- Ammonia
- Mercury

2.2 Draft Biomethane Specification

At the commencement of the project, it was determined that a baseline specification was required in order to proceed with conceptual design for biogas upgrading plants. In order to determine a specification, information available at the time was utilized to determine a conservative specification. The intent of this specification was not to be a final specification, but only to be a starting point for analysis. This specification, along with background on the criteria, is presented in Table 1.

Note that non-detect – detection limit to be determined (N.D. - DL TBD) was utilized as a placeholder for values that there was not enough existing data to determine a specification for, or detection limits for the analysis method were not known at that time.

Gas Quality guidelines are revised and addressed in Section 6.0.

Component/Property	Minimum Quality Criteria	Criteria Based On
Methane (CH_4)	>96%	Heating Value
Total Inert Content	<4% by volume	Max. Total Inert Content
Carbon Dioxide (CO_2)	<2% by volume	TCPL tariff
Carbon Monoxide (CO)	N.D.	Existing Standard: France: < 2% Note: Should not be CO present in biogas unless there is combustion occurring in a landfill. CO may be present in gas from gasification plants.
Oxygen (O_2)	<0.2% by volume	AGA report 4A (under revision, is oxygen spec changing?) Note: European standards are <0.5% (except France <0.01% and Sweden <1%) Note: TCPL tariff is <0.4% by volume
Hydrogen (H_2)	<0.1%	Marcogaz Interchangeability
Total Sulphur	<10 mg/m^3	Existing Standards: Austria: <10 mg/m3 France, Germany, nd Switzerland: <30 mg/m3 Netherlands: <45 mg/m3 Sweden: <23 mg/m3 TCPL Tariff: <115 mg/m3
Hydrogen Sulphide	<7 mg/m^3	CSA Z662 Note TCPL Tariff <23 mg/m3
VOCs including Halogenated Compounds and Siloxanes	N.D. - DL TBD	Existing Standards for Halogenated Compounds: Austria: 0 mg/m3 France: <1 mg Cl/m3 and < 10 mg F/m3 Germany: nil Netherlands: < 25 mg Cl/m3 Existing Standards for Siloxanes: Austria: <10mg/m3
Ammonia	N.D. - DL TBD	Existing standards: Austria: "Technically Pure" Netherlands: <3 mg/Nm3 Sweden: <20 mg/Nm3
Mercury	N.D. - DL TBD	Existing Standard: France: < 1 μg/m^3
Lead	N.D. - DL TBD	No existing standard
Water Vapour Content	<65 mg/m^3	TCPL tariff
Gross Heating Value (dry basis)	>36 MJ/m^3	TCPL tariff
Specific Gravity	0.55-0.59	S.G. of CH_4
Wobbe Index	47.20 MJ/m^3 – 51.14 MJ/m^3	TCPL Tariff under revision Interchangeability +/- 4% Historical
Particulates	Technically Pure	
Active Bacteria & Bacterial Agents	N.D. - DL TBD	TCPL tariff under revision for LNG

Table 1- Draft Biomethane Specification

3.0 Gas Analysis

Gas analysis of biogas, biomethane, and natural gas was completed to determine what gas compositions were possible at existing sites. In order to complete gas analysis, a laboratory with the right capabilities was required.

3.1 Lab Selection

After commencing the Draft Biomethane Specification, the search for a lab capable of completing the gas sampling and analysis for listed components started. Several potential partner labs were identified and contacted, including:

- Maxxam Analytics
- OSB Services
- Mold and Bacteria Lab (MBL)
- Air Toxics
- Ortech Environmental
- Gas Technology Institute (GTI)

The first site, biogas from anaerobic digester, was scheduled for gas sampling in Canada in July 2008. It was decided to utilize local laboratories for this site. The labs that were utilized were:

- OSB Services (Perform Sampling and Trace Analysis)
- Maxxam Analytics (Major Components and Sulphur Analysis)
- MBL (Bacteria Identification)

The results of the first sample set are included in Appendix C. The balance of the report will focus on the remaining sample sites.

As sample sites were identified, and site access was granted, it became clear that the majority of these sites would be located in the United States. Transportation of gas samples across the border through customs is possible, but may lead to delays in the arrival of the samples at the lab. Tedlar bag samples must arrive at the lab in a 24 hour time frame for sulphur analysis to minimize deterioration.[3] For that reason, it was determined that the number of samples moving across the border should be minimized. In selecting a lab, other considerations were also important, including ability of the lab to provide staff for gas sampling, sample methods, gas analysis methods, and the option to deal with only one lab directly, even if certain gas analysis were subcontracted.

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[3] ASTM International, "**Designation: D 6228 – 98 (Reapproved 2003) Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection**"

To ensure meaningfulness of the samples collected, the repeatability of the sampling procedure was also an important consideration in selecting only one lab to complete sampling.

GTI was selected as the lab to perform the remaining sampling and gas analysis. Two lab staff members provided gas sampling services at each site. Samples within the US were sent by GTI via FedEx back to the lab located in Des Plaines, IL. Samples within Canada were sent by Enbridge via FedEx back to the lab located in Des Plaines, IL. A tiered sampling and analysis approach was utilized to meet the requirements for determination of gas composition.

3.2 Tiered Approach

Analytical approach for biogas from the anaerobic digester is documented in Appendix C. Remaining gas analysis was separated into three tiers: First Tier Chemical Testing, Second Tier Chemical Testing, and Biological Testing. As per Figure 2, First Tier Chemical Testing included major components, sulphur, siloxanes, extended hydrocarbons, mercury and metals, halocarbons, and ammonia. Second Tier Chemical Testing included volatile organic compounds (VOCs)/semi-volatile organic compounds (SVOCs), polychlorinated biphenyls (PCBs), Pesticides, Ketones/Aldehydes, and QA/QC. Also included in Figure 2 is the reference standard or instrument used.

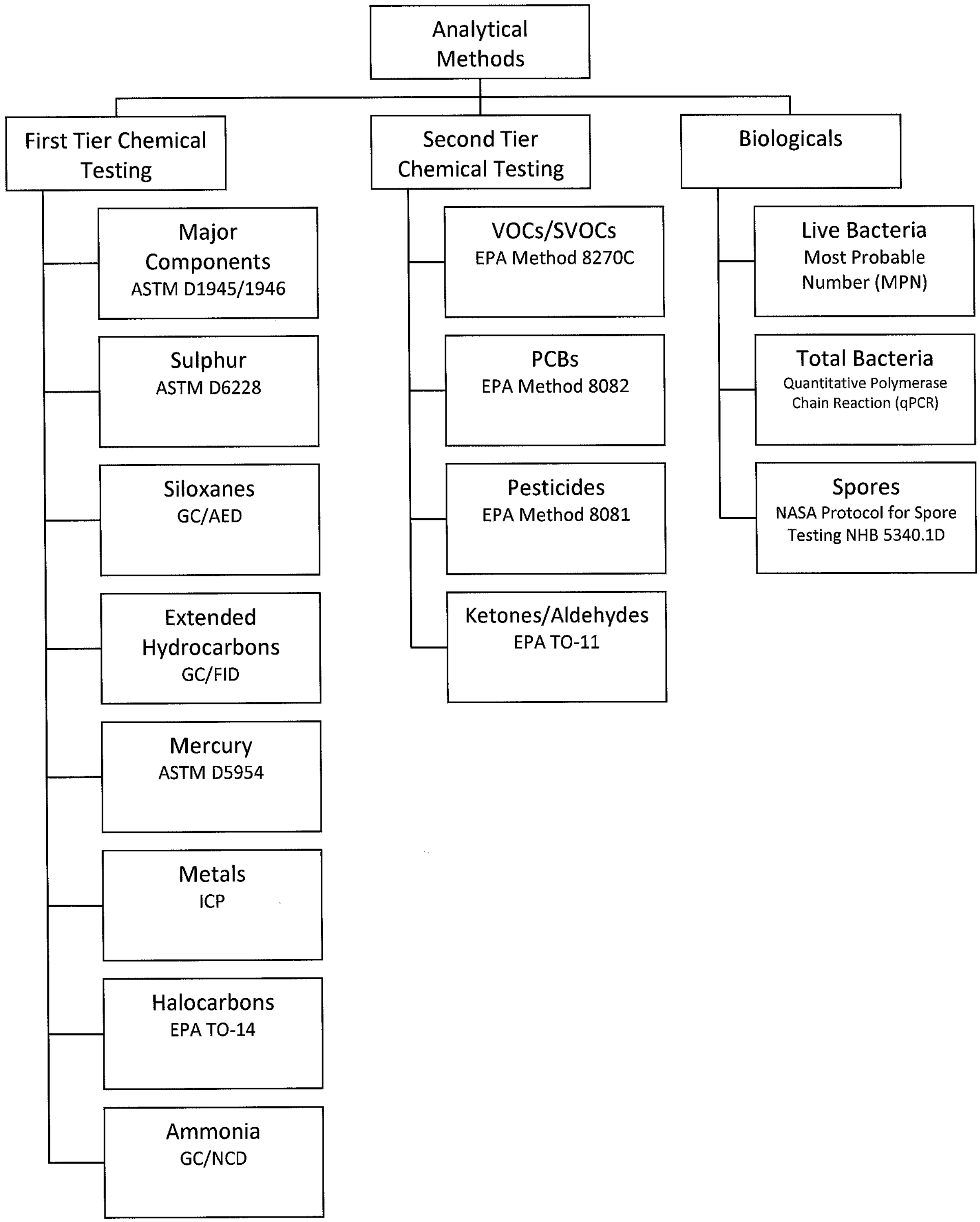

Figure 2 - Tiered Approach to Analysis

Four package options were offered for Biological Testing. The most comprehensive package, Package D, was selected for all biological testing. Biological samples were only collected from Biomethane and Natural Gas supplies.

Package	Biological Tests
A	Total live bacteria #, MIC bacteria #
B	Total live bacteria #, 20 major bacteria ID
C	Total live bacteria #, MIC bacteria #, 20 major bacteria ID
D	Total live anaerobic bacteria #, MIC bacteria #, 20 major bacteria ID, anaerobic spore #, 10 anaerobic spore ID

Table 2 - Biological Testing Levels

4.0 Gas Sampling

In order to obtain biogas and biomethane samples, site access at existing biomethane injections sites was required. In order to capture variation in gas quality, it was preferred that these sites utilize different biomass sources, and employ different clean up technologies.

Once sites were selected, scheduling of sampling took place in order to accommodate both the site and the lab schedules.

Sampling was performed over a six month period, commending in October 2008 and finishing in March 2009. On site during sampling, there were two lab employees to complete sampling, and one Enbridge employee as the site contact.

4.1 Site Selection

Several sites were contacted in order to locate sites that were willing to have biogas and biomethane samples retrieved. It was agreed that all sites would remain confidential. The sites selected are presented in Table 3.

	Sample Type(s)	# of Visits Required	# of Samples per Visit	Total Samples from Site	Sampling Completed By
Anaerobic Digester	Raw Biogas	1	2 BG	2	OSB
Landfill site 1	Raw LFG and Biomethane	2	2 LFG + 2 BM	8	GTI
Landfill site 2	Raw LFG and Biomethane	2	2 LFG + 2 BM	8	GTI
Landfill site 3	Raw LFG and Biomethane	2	2 LFG + 2 BM	8	GTI
WWTP with Upgraded Stream	WWTP gas and Biomethane	1	4 WWTP + 4 BM	8	GTI
WWTP without Upgrading	WWTP gas	1	2 WWTP	2	GTI
Natural Gas - Utility A	Natural Gas	1	2 NG	2	GTI
Natural Gas - Utility B	Natural Gas	1	2 NG	2	GTI
Natural Gas - Utility C	Natural Gas	1	2 NG	2	GTI
Totals		**12**		**42**	

Table 3 - Gas Sample Plan

4.2 Sample Scheduling

For each visit at a site, two sets of samples were retrieved. For sites with gas upgrading, each sample set contained biogas samples and biomethane samples. For sites without upgrading, each sample set contained either biogas samples or natural gas samples. For sites with upgrading, it was decided to double the number of sample sets retrieved to four to obtain a sufficient sample size for statistical analysis within the project budget constraints. Landfill sites with upgrading were visited twice, with two sample sets collected at each visit. The project constraints refrained us from extensive analysis of the effects on seasonality on the quality of biomethane, however we tried to address this by scheduling two separate visits to the same sites collect gas samples. The wastewater treatment plant with upgrading was visited once, with sample sets collected on two consecutive dates. This was done as a measure of practicality due to the location of the site and the requirement to ship all equipment to site on a pallet.

One of the landfill sites sampled employed blending with natural gas prior to injection in order to meet tariff gas quality requirements. However, the sampling at this site was completed at the end of the upgrading process prior to blending. This was done in order to address biomethane quality as a result of the upgrading process, and not the effects of blending.

Ten consecutive sampling hours were required in order to retrieve two sample sets at an upgrading site. The sampling time includes equipment setup, retrieval of two sets of samples, and removal of the sampling equipment.

The first sample set from the landfills was retrieved the week of October 20, 2008. The second week of sampling took place week of November 17, 2008. One plant was not in operation during the week of sampling in November 2008, therefore the second sample set was retrieved from this site the week of February 2, 2009.

Samples were retrieved from the wastewater treatment plant with upgrading the week of November 3, 2008.

Samples were retrieved from Utility A, Utility B, and the wastewater treatment plant without upgrading the week of December 8, 2008.

Samples were retrieved from Utility C the week of March 16, 2009.

4.3 Sampling Methods

Several sampling methods were employed in order to obtain the samples required for analysis. Methods employed for each component are shown in Figure 3. These methods are further explained in Appendix D.

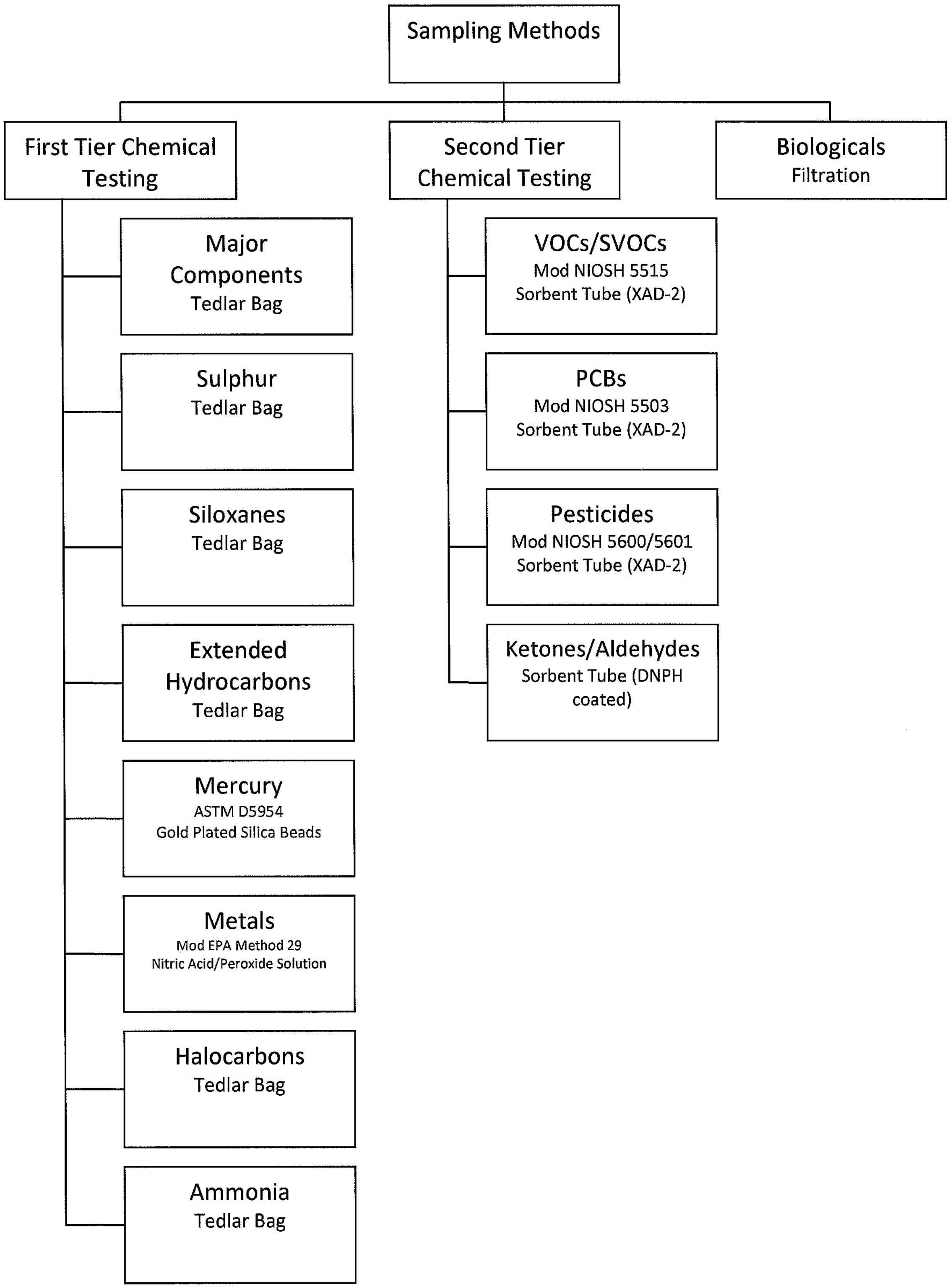

Figure 3 - Sampling Methods

5.0 Analysis of Results

Laboratory results for the samples obtained from the landfill sites, wastewater treatment sites, and natural gas sites can be found in Appendix D.

The analysis of laboratory results was conducted using statistical analysis. The first step in the analysis was to determine upper and/or lower limits for biomethane parameters including trace contaminants. Laboratory results for natural gas from Utility A and B, Landfills 1, 2, and 3, and Wastewater Treatment Plant with upgrading were all compared to upper and/or lower limits based on a definition of pipeline quality gas. Samples from Utility A and Utility B were combined to obtain a better statistical sample size given the same origin of the gas. Chemical components were further analyzed if they met one of the following criteria:

- Found in biomethane but not in natural gas
- Found in biomethane in equal or greater amounts than in natural gas samples

5.1 Pipeline Quality Gas and Acceptable Concentration Levels

Upper and/or lower limits were defined based on pipeline quality gas requirements, and on published acceptable limits for trace contaminants.

It must be noted that analysis would have to be repeated and results revised for different tariff requirements or different limits for trace contaminants.

5.1.1 Definition of Pipeline Quality Gas

For the purposes of this report, pipeline quality gas will be defined by the general terms and conditions of the applicable transportation tariff. As per the TransCanada Pipeline transportation tariff[4], the following properties will be considered as the tariff requirements:

- 36 MJ/m3 ≤ Energy Content ≤ 41.34 MJ/m3
- 47.23 MJ/m3 ≤ Wobbe Index ≤ 51.16 MJ/m3
- H_2S ≤23 mg/m^3 Total S ≤ 115 mg/m3
- CO_2 ≤ 2 Vol%
- Water Vapour ≤ 65 mg/m3
- O_2 ≤ 0.4 Vol%
- Total Inerts ≤ 4 Mol%
- Butane Plus ≤ 1.5 Mol%

[4] TransCanada Pipelines Limited, *Transportation Tariff - General Terms and Conditions*, (Feb. 1, 2009). Retrieved from http://www.transcanada.com/Mainline/info_postings/tariff/19gtc.pdf

Note that for gases, that the Mol% is equivalent to the Vol%.

5.1.2 Acceptable Concentration Levels for Trace Contaminants

Acceptable concentration levels for trace contaminants have been based on Exposure Limiting Values published in the Ontario Occupation Health and Safety Act (OH&SA) R.R.O. Regulation 883 Control of Exposure to Biological or Chemical Agents. In instances when an exposure limiting value is not cited in the OH&SA Reg. 833, exposure limiting values from the United States Department of Labour Occupation Safety & Health Administration (OSHA) were referenced. In some instances, there is no exposure limiting value in either the OH&SA Reg. 833 or OSHA. In this case, exposure limiting values published by the National Institute for Occupation Safety and Health (NIOSH) were referenced.

Exposure Limiting Values are referenced, as it is assumed that the worst case exposure is to a worker at the biogas upgrading site, or to a worker responding to a damage within a network that is distributing biomethane.

OH&SA Exposure Limiting Values could be cited as one of three values:

- Time Weighted Exposure Value (TWAEV)
    - Average airborne concentration to which a worker is exposed in a work day or a work week
- Short Term Exposure Value (STEV)
    - Maximum airborne concentration to which a worker is exposed in any fifteen minute period determine from a single sample or a time-weighted average of sequential samples taken during such period
- Ceiling Exposure Value (CEV)
    - Maximum airborne concentration to which a worker is exposed at any time

If two or more of the above values were cited for one agent, the most conservative value was chosen for comparison.

OSHA Permissible Exposure Limits (PELs) are 8-hour time weighted averages, unless otherwise noted.

NIOSH Recommended Exposure Limits (RELs) are 10-hour time weighted averages, unless otherwise noted. NIOSH RELs are not legal standards. They are recommendations from scientists at NIOSH to OSHA. These recommendations are based on animal and human studies.

In instances where there are no exposure limiting value cited in OH&SA, OSHA, or NIOSH, there is no known acceptable concentration level. The mean and standard deviation of the sample set was determined, and at a 95% confidence level the interval of the process mean was determined: [lower limit process mean, upper limit process mean].

5.2 Statistical Analysis

5.2.1 Analysis of Natural Gas Compliance to Tariff Criteria

In order to determine the probability that natural gas samples meet tariff criteria, statistical analysis was completed on three NG samples. At the time of statistical analysis, the laboratory results were only available for Utility A and Utility B. Laboratory results for all three utility sites are included in Appendix D. It is assumed that the NG parameters are the output of a random process and falling within +/-3σ (σ is standard deviation) of the process parameter mean, resulting in a normal distribution of values for each parameter. Given the small sample size, t-distribution analysis was utilized to make inferences about the NG process.

Table 4 summarizes the statistical analysis for comparison of natural gas to pipeline quality gas as defined in Section 1. In Table 4, the columns "Lower Limit Mean" and "Upper Limit Mean" define a 95% Confidence Interval for the process mean. The column P(mean > TCPL LL) provides the probability that the process mean will be greater than the TCPL lower limit for that property/component. The column P(mean < TCPL UL) provides the probability that the process mean will be less than the TCPL upper limit for that property/component.

	Confidence Interval	Lower Limit Mean	Upper Limit Mean	P(mean > TCPL LL)	P(mean < TCPL UL)
NG_HHV(MJ/m3)	95%	38.28	38.40	100.00%	100.00%
NG_Wobbe (MJ/m3)	95%	50.30	50.50	100.00%	99.95%
NG_H2S (mg/m3)	95%	-0.011	0.38	NA	99.98%
NG_Total Sulphur (mg/m3)	95%	-0.36	2.56	NA	100.00%
NG_CO2 (Mole %)	95%	0.69%	0.79%	NA	100.00%
NG_O2 (Mole%)	95%	NA	NA	NA	NA
NG_Total Inerts (Mole%)	95%	0.69%	1.25%	NA	99.98%
NG_Butanes Plus (Mole %)	95%	0.062%	0.17%	NA	100.00%

Table 4 - Comparison of Natural Gas to Pipeline Quality Gas Specifications

The following subsections outline the results of Table 4 for each tariff component separately. The degrees of freedom are defined as *(n – 1)* where *n* is the number of samples that were above the detection limit for the corresponding property or component.

5.2.1.1. Gross Heating Value

- Minimum Tariff Limit Criteria: 36 MJ/m3
- Maximum Tariff Limit Criteria: 41.34 MJ/m3
- Sample Mean: 38.34 MJ/m3
- Sample Standard Deviation: 0.024 MJ/m3

- Sample Standard Error: 0.014 MJ/m3
- Degrees of Freedom: 2
- T-Multiple at 95% Confidence Interval: 4.303

95% Confident that the process mean is within the interval:
[38.28 MJ/m3, 38.40 MJ/m3]

Based on the analysis, the process mean of gross heating value of NG will meet the tariff requirements with 100.00% probability.

5.2.1.2. Wobbe Index

- Minimum Tariff Limit Criteria: 47.23 MJ/m3
- Maximum Tariff Limit Criteria: 51.16 MJ/m3
- Sample Mean: 50.401 MJ/m3
- Sample Standard Deviation: 0.041 MJ/m3
- Sample Standard Error: 0.024 MJ/m3
- Degrees of Freedom: 2
- T-Multiple at 95% Confidence Interval: 4.303

95% Confident that the process mean is within the interval:
[50.30 MJ/m3, 50.50 MJ/m3]

Based on the analysis, the process mean of Wobbe Index of NG will meet the lower limit tariff requirement with 100.00% probability. The upper limit requirement will be met with 99.95% probability.

5.2.1.3. Hydrogen Sulphide

- Maximum Tariff Limit Criteria: 23 mg/m3
- Sample Mean: 0.18 mg/m3
- Sample Standard Deviation: 0.022 mg/m3
- Sample Standard Error: 0.015 mg/m3
- Degrees of Freedom: 1
- T-Multiple at 95% Confidence Interval: 12.706

95% Confident that the process mean is within the interval: [0, 0.38 mg/m3]

Based on the analysis, the process mean of hydrogen sulphide in NG will meet the tariff requirement with 99.98% probability.

5.2.1.4. Total Sulphur

- Maximum Tariff Limit Criteria: 115 mg/m3
- Sample Mean: 1.10 mg/m3
- Sample Standard Deviation: 0.59 mg/m3
- Sample Standard Error: 0.34 mg/m3
- Degrees of Freedom: 2
- T-Multiple at 95% Confidence Interval: 4.303

95% Confident that the process mean is within the interval: [0, 2.56 mg/m3]

Based on the analysis, the process mean of total sulphur in NG will meet the tariff requirement with 100.00% probability.

5.2.1.5. Carbon Dioxide

- Maximum Tariff Limit Criteria: 2 Vol% ≈ 2 Mol%
- Sample Mean: 0.74 Mol%
- Sample Standard Deviation: 0.021 Mol%
- Sample Standard Error: 0.012 Mol%
- Degrees of Freedom: 2
- T-Multiple at 95% Confidence Interval: 4.303

95% Confident that the process mean is within the interval:
[0.69 Mol%, 0.79 Mol%]

Based on the analysis, the process mean for carbon dioxide in NG will meet the tariff requirement with 100.00% probability.

5.2.1.6. Water Vapour

The gas samples were not analyzed for water vapour.

5.2.1.7. Oxygen

- Maximum Tariff Limit Criteria: 0.4 Vol% ≈ 0.4 Mol%

No statistical analysis is possible for oxygen levels in NG, as all samples were below the detection limit of 0.03 Mol %. It is observed that 0.03 Mol% is by an order of magnitude lower than the tariff upper limit of 0.4 Mol%.

5.2.1.8. Total Inerts

- Maximum Tariff Limit Criteria: 4 Mol%
- Sample Mean: 0.97 Mol%
- Sample Standard Deviation: 0.11 Mol%
- Sample Standard Error: 0.065 Mol%
- Degrees of Freedom: 2
- T-Multiple at 95% Confidence Interval: 4.303

95% Confident that the process mean is within the interval: [0.69 Mol%, 1.25 Mol%]

Based on the analysis, the process mean for total inerts in NG will meet the tariff requirement with 99.98% probability.

5.2.1.9. Butanes Plus

- Maximum Tariff Limit Criteria: 1.5 Mol%
- Sample Mean: 0.12 Mol%
- Sample Standard Deviation: 0.022 Mol%
- Sample Standard Error: 0.013 Mol%
- Degrees of Freedom: 2
- T-Multiple at 95% Confidence Interval: 4.303

95% Confident that the process mean is within the interval: [0.061 Mol%, 0.17 Mol%]

Based on the analysis, the process mean for butanes plus in NG will meet the tariff requirement with 100.00% probability.

5.2.1.10. Conclusion – Natural Gas Compliance to Tariff

Based on t-distribution analysis of the means of the tariff parameters for NG, NG will meet tariff requirements with 99.95% probability.

5.2.2 Analysis of Biomethane Compliance to Tariff Criteria

In order to determine the probability that biomethane samples meet tariff criteria, statistical analysis was completed separately for four sites: LF1, LF2, LF3, and WWTP1. It is assumed that the biomethane production is a random process whose parameters fall within +/-3σ (σ is standard deviation) of the process parameter mean, resulting in a normal distribution of values for each parameter. Given the small sample size, t-distribution analysis was utilized to make inferences about the biomethane process.

5.2.2.1. Biomethane from LF1

Table 5 provides a summary of the results of the statistical analysis for four biomethane samples from LF1. In Table 5, the columns "Lower Limit Mean" and "Upper Limit Mean" define a 95% Confidence Interval for the process mean. The column P(mean > TCPL LL) provides the probability that the process mean will be greater than the TCPL lower limit for that property/component. The column P(mean < TCPL UL) provides the probability that the process mean will be less than the TCPL upper limit for that property/component.

	Confidence Interval	Lower Limit Mean	Upper Limit Mean	P(mean > TCPL LL)	P(mean < TCPL UL)
LF1_HHV(MJ/m3)	95%	36.47	37.19	99.74%	100.00%
LF1_Wobbe (MJ/m3)	95%	48.29	49.68	99.80%	99.78%
LF1_H2S (mg/m3)	95%	NA	NA	NA	NA
LF1_Total Sulphur (mg/m3)	95%	0.02	0.20	NA	100.00%
LF1_CO2 (Mole %)	95%	0.63%	1.56%	NA	99.57%
LF1_O2 (Mole%)	95%	NA	NA	NA	NA
LF1_Total Inerts (Mole%)	95%	0.39%	1.41%	NA	99.99%
LF1_Butanes Plus (Mole %)	95%	0.0001%	0.0001%	NA	NA

Table 5 - Comparison of LF1 Biomethane to Pipeline Quality Gas Specifications

The following subsections outline each tariff component separately. The degrees of freedom are defined as *(n – 1)* where *n* is the number of samples that were above the detection limit for the corresponding property or component.

5.2.2.1.1. Gross Heating Value

- Minimum Tariff Limit Criteria: 36 MJ/m3
- Maximum Tariff Limit Criteria: 41.34 MJ/m3
- Sample Mean: 36.83 MJ/m3
- Sample Standard Deviation: 0.23 MJ/m3
- Sample Standard Error: 0.11 MJ/m3
- Degrees of Freedom: 3
- T-Multiple at 95% Confidence Interval: 3.182

95% Confident that the process mean is within the interval:
[36.47 MJ/m3, 37.19 MJ/m3]

Based on the analysis, the process mean for gross heating value in biomethane from LF1 will meet the lower limit tariff requirement with 99.74% probability. The upper limit tariff requirement will be met with 100.00% probability.

5.2.2.1.2. Wobbe Index

- Minimum Tariff Limit Criteria: 47.23 MJ/m3
- Maximum Tariff Limit Criteria: 51.16 MJ/m3
- Sample Mean: 48.99 MJ/m3

- Sample Standard Deviation: 0.44 MJ/m3
- Sample Standard Error: 0.22 MJ/m3
- Degrees of Freedom: 3
- T-Multiple at 95% Confidence Interval: 3.182

95% Confident that the process mean is within the interval:
[48.29 MJ/m3, 49.68 MJ/m3]

Based on the analysis, the process mean for Wobbe Index in biomethane from LF1 will meet the lower limit tariff requirement with 99.80% probability. The upper limit tariff requirement will be met with 99.78% probability.

5.2.2.1.3. Hydrogen Sulphide

- Maximum Tariff Limit Criteria: 23 mg/m3

No statistical analysis is possible for hydrogen sulphide levels for biomethane from LF1, as all samples were below the detection limit of 0.05 ppmv. Assuming 101.325 kPa and 15°C, 0.05 ppmv is equivalent to 0.72 mg/m3, which is noticeably below the tariff limit of 23 mg/m3.

5.2.2.1.4. Total Sulphur

- Maximum Tariff Limit Criteria: 115 mg/m3
- Sample Mean: 0.11 mg/m3
- Sample Standard Deviation: 0.010 mg/m3
- Sample Standard Error: 0.0072 mg/m3
- Degrees of Freedom: 1
- T-Multiple at 95% Confidence Interval: 12.71

95% Confident that the process mean is within the interval:
[0.0016 mg/m3, 0.20 mg/m3]

Based on the analysis, the process mean for total sulphur in biomethane from LF1 will meet the tariff requirement with 100.00% probability.

5.2.2.1.5. Carbon Dioxide

- Maximum Tariff Limit Criteria: 2 Vol% ≈ 2 Mol%
- Sample Mean: 1.10 Mol%
- Sample Standard Deviation: 0.29 Mol%
- Sample Standard Error: 0. 15 Mol%
- Degrees of Freedom: 3

- T-Multiple at 95% Confidence Interval: 3.182

95% Confident that the process mean is within the interval: [0.63 Mol%, 1.56 Mol%]

Based on the analysis, the process mean for carbon dioxide in biomethane from LF1 will meet the tariff requirement with 99.57% probability.

5.2.2.1.6. Water Vapour

The gas samples were not analyzed for water vapour.

5.2.2.1.7. Oxygen

- Maximum Tariff Limit Criteria: 0.4 Vol% ≈ 0.4 Mol%

No statistical analysis is possible for oxygen levels in biomethane from LF1, as all samples were below the detection limit of 0.03 Mol %. It is observed that 0.03 Mol% is by an order of magnitude lower than the tariff upper limit of 0.4 Mol%.

5.2.2.1.8. Total Inerts

- Maximum Tariff Limit Criteria: 4 Mol%
- Sample Mean: 0.90 Mol%
- Sample Standard Deviation: 0.32 Mol%
- Sample Standard Error: 0.16 Mol%
- Degrees of Freedom: 3
- T-Multiple at 95% Confidence Interval: 3.182

95% Confident that the process mean is within the interval: [0.39 Mol%, 1.41 Mol%]

Based on the analysis, the process mean for total inerts in biomethane from LF1 will meet the tariff requirements with 99.99% probability.

5.2.2.1.9. Butanes Plus

- Maximum Tariff Limit Criteria: 1.5 Mol%
- Sample Mean: 0.00010 Mol%
- Sample Standard Deviation: 0
- Sample Standard Error: 0
- Degrees of Freedom: 1
- T-Multiple at 95% Confidence Interval: 12.706

95% Confident that the process mean is within the interval:

[0.00010 Mol%, 0.00010 Mol%]

The probability that the process mean for butanes plus in biomethane from LF1 will meet the tariff requirements is not calculable as the standard error it zero. Of the four samples analyzed, 2 were BDL, and 2 were 0.0010 Mol%.

5.2.2.1.10. Conclusion – LF1 Biomethane Compliance to Tariff

Based on t-distribution analysis of the means of the tariff parameters for LF1 Biomethane, LF1 Biomethane will meet tariff requirements with 99.57% probability.

5.2.2.2. Biomethane from LF2

Table 6 provides a summary of the results of the statistical analysis for four biomethane samples from LF2. In Table 6, the columns "Lower Limit Mean" and "Upper Limit Mean" define a 95% Confidence Interval for the process mean. The column P(mean > TCPL LL) provides the probability that the process mean will be greater than the TCPL lower limit for that property/component. The column P(mean < TCPL UL) provides the probability that the process mean will be less than the TCPL upper limit for that property/component.

	Confidence Interval	Lower Limit Mean	Upper Limit Mean	P(mean > TCPL LL)	P(mean < TCPL UL)
LF2_HHV(MJ/m3)	95%	36.19	36.97	99.11%	100.00%
LF2_Wobbe (MJ/m3)	95%	47.76	48.96	99.53%	99.93%
LF2_H2S (mg/m3)	95%	0.42	0.94	NA	100.00%
LF2_Total Sulphur (mg/m3)	95%	0.70	2.22	NA	100.00%
LF2_CO2 (Mole %)	95%	0.33%	1.10%	NA	99.91%
LF2_O2 (Mole%)	95%	NA	NA	NA	NA
LF2_Total Inerts (Mole%)	95%	2.19%	4.24%	NA	95.41%
LF2_Butanes Plus (Mole %)	95%	0.000032%	0.00097%	NA	100.00%

Table 6 - Comparison of LF2 Biomethane to Pipeline Quality Gas Specifications

The following subsections outline each tariff component separately. The degrees of freedom are defined as *(n – 1)* where *n* is the number of samples that were above the detection limit for the corresponding property or component.

5.2.2.2.1. Gross Heating Value

- Minimum Tariff Limit Criteria: 36 MJ/m3
- Maximum Tariff Limit Criteria: 41.34 MJ/m3
- Sample Mean: 36.56 MJ/m3
- Sample Standard Deviation: 0.25 MJ/m3
- Sample Standard Error: 0.12 MJ/m3
- Degrees of Freedom: 3
- T-Multiple at 95% Confidence Interval: 3.182

95% Confident that the process mean is within the interval:

[36.19 MJ/m3, 36.97 MJ/m3]

Based on the analysis, the process mean for gross heating value in biomethane from LF2 will meet the lower limit tariff requirement with 99.11% probability. The upper limit tariff requirement will be met with 100.00% probability.

5.2.2.2.2. Wobbe Index

- Minimum Tariff Limit Criteria: 47.23 MJ/m3
- Maximum Tariff Limit Criteria: 51.16 MJ/m3
- Sample Mean: 48.36 MJ/m3
- Sample Standard Deviation: 0.38 MJ/m3
- Sample Standard Error: 0.19 MJ/m3
- Degrees of Freedom: 3
- T-Multiple at 95% Confidence Interval: 3.182

95% Confident that the process mean is within the interval:
[47.76 MJ/m3, 48.96 MJ/m3]

Based on the analysis, the process mean for Wobbe Index in biomethane from LF2 will meet the lower limit tariff requirement with 99.53% probability. The upper limit tariff requirement will be met with 99.93% probability.

5.2.2.2.3. Hydrogen Sulphide

- Maximum Tariff Limit Criteria: 23 mg/m3
- Sample Mean: 0.68 mg/m3
- Sample Standard Deviation: 0.16 mg/m3
- Sample Standard Error: 0.081 mg/m3
- Degrees of Freedom: 3
- T-Multiple at 95% Confidence Interval: 3.182

95% Confident that the process mean is within the interval: [0.42 mg/m3, 0.94 mg/m3]

Based on the analysis, the process mean for hydrogen sulphide in biomethane from LF2 will meet the tariff requirement with 100.00% probability.

5.2.2.2.4. Total Sulphur

- Maximum Tariff Limit Criteria: 115 mg/m3
- Sample Mean: 1.46 mg/m3
- Sample Standard Deviation: 0.48 mg/m3
- Sample Standard Error: 0.24 mg/m3

- Degrees of Freedom: 3
- T-Multiple at 95% Confidence Interval: 3.182

95% Confident that the process mean is within the interval:
[0.70 mg/m3, 2.22 mg/m3]

Based on the analysis, the process mean for total sulphur in biomethane from LF2 will meet the tariff requirement with 100.00% probability.

5.2.2.2.5. Carbon Dioxide

- Maximum Tariff Limit Criteria: 2 Vol% ≈ 2 Mol%
- Sample Mean: 0.72 Mol%
- Sample Standard Deviation: 0.24 Mol%
- Sample Standard Error: 0. 12 Mol%
- Degrees of Freedom: 3
- T-Multiple at 95% Confidence Interval: 3.182

95% Confident that the process mean is within the interval: [0.33 Mol%, 1.10 Mol%]

Based on the analysis, the process mean for carbon dioxide in biomethane from LF2 will meet the tariff requirement with 99.91% probability.

5.2.2.2.6. Water Vapour

The gas samples were not analyzed for water vapour.

5.2.2.2.7. Oxygen

- Maximum Tariff Limit Criteria: 0.4 Vol% ≈ 0.4 Mol%

No statistical analysis is possible for oxygen levels in biomethane from LF2, as all samples were below the detection limit of 0.03 Mol %. It is observed that 0.03 Mol% is by an order of magnitude lower than the tariff upper limit of 0.4 Mol%.

5.2.2.2.8. Total Inerts

- Maximum Tariff Limit Criteria: 4 Mol%
- Sample Mean: 3.21 Mol%
- Sample Standard Deviation: 0.64 Mol%
- Sample Standard Error: 0.32 Mol%
- Degrees of Freedom: 3
- T-Multiple at 95% Confidence Interval: 3.182

95% Confident that the process mean is within the interval: [2.19 Mol%, 4.24 Mol%]

Based on the analysis, the process mean for total inerts in biomethane from LF2 will meet the tariff requirements with 95.41% probability.

5.2.2.2.9. Butanes Plus

- Maximum Tariff Limit Criteria: 1.5 Mol%
- Sample Mean: 0.00050 Mol%
- Sample Standard Deviation: 0.00029 Mol%
- Sample Standard Error: 0.00015 Mol%
- Degrees of Freedom: 3
- T-Multiple at 95% Confidence Interval: 3.182

95% Confident that the process mean is within the interval:
[0.000032 Mol%, 0.00097 Mol%]

Based on the analysis, the process mean for butanes plus in biomethane from LF2 will meet the tariff requirements with 100.00% probability.

5.2.2.2.10. Conclusion – LF2 Biomethane Compliance to Tariff

Based on t-distribution analysis of the means of the tariff parameters for LF2 Biomethane, LF2 Biomethane will meet tariff requirements with 95.41% probability.

5.2.2.3. Biomethane from LF3

Table 7 provides a summary of the results of the statistical analysis for four biomethane samples from LF3. In Table 7, the columns "Lower Limit Mean" and "Upper Limit Mean" define a 95% Confidence Interval for the process mean. The column P(mean > TCPL LL) provides the probability that the process mean will be greater than the TCPL lower limit for that property/component. The column P(mean < TCPL UL) provides the probability that the process mean will be less than the TCPL upper limit for that property/component.

	Confidence Interval	Lower Limit Mean	Upper Limit Mean	P(mean > TCPL LL)	P(mean < TCPL UL)
LF3_HHV(MJ/m3)	95%	34.55	35.45	0.30%	100.00%
LF3_Wobbe (MJ/m3)	95%	44.71	46.48	0.50%	99.99%
LF3_H2S (mg/m3)	95%	NA	NA	NA	NA
LF3_Total Sulphur (mg/m3)	95%	1.15	3.76	NA	100.00%
LF3_CO2 (Mole %)	95%	0.23%	1.20%	NA	99.83%
LF3_O2 (Mole%)	95%	NA	NA	NA	NA
LF3_Total Inerts (Mole%)	95%	6.18%	8.59%	NA	0.15%
LF3_Butanes Plus (Mole %)	95%	-0.00041%	0.0018%	NA	100.00%

Table 7 - Comparison of LF3 Biomethane to Pipeline Quality Gas Specifications

The following subsections outline each tariff component separately. The degrees of freedom are defined as *(n – 1)* where *n* is the number of samples that were above the detection limit for the corresponding property or component.

5.2.2.3.1. Gross Heating Value

- Minimum Tariff Limit Criteria: 36 MJ/m3
- Maximum Tariff Limit Criteria: 41.34 MJ/m3
- Sample Mean: 35.00 MJ/m3
- Sample Standard Deviation: 0.29 MJ/m3
- Sample Standard Error: 0.14 MJ/m3
- Degrees of Freedom: 3
- T-Multiple at 95% Confidence Interval: 3.182

95% Confident that the process mean is within the interval:
[34.55 MJ/m3, 35.45 MJ/m3]

Based on the analysis, the process mean for gross heating value in biomethane from LF3 will meet the lower limit tariff requirement with 0.30% probability. This result was expected, as the plant was designed for blending biomethane and natural gas prior to injection and the biomethane sample was taken prior to blending stage.

5.2.2.3.2. Wobbe Index

- Minimum Tariff Limit Criteria: 47.23 MJ/m3
- Maximum Tariff Limit Criteria: 51.16 MJ/m3
- Sample Mean: 45.60 MJ/m3
- Sample Standard Deviation: 0.56 MJ/m3
- Sample Standard Error: 0.28 MJ/m3
- Degrees of Freedom: 3
- T-Multiple at 95% Confidence Interval: 3.182

95% Confident that the process mean is within the interval:
[44.71 MJ/m3, 46.48 MJ/m3]

Based on the analysis, the process mean for Wobbe Index in biomethane from LF3 will meet the lower limit tariff requirement with 0.5% probability. This result was expected, as the plant was designed for blending biomethane and natural gas prior to injection and the biomethane sample was taken prior to blending stage.

5.2.2.3.3. Hydrogen Sulphide

- Maximum Tariff Limit Criteria: 23 mg/m3

No statistical analysis is possible for hydrogen sulphide levels for biomethane from LF3, as all samples were below the detection limit of 0.05 ppmv. Assuming 101.325 kPa and 15°C, 0.05 ppmv is equivalent to 0.72 mg/m3, which is noticeably below the tariff limit of 23 mg/m3.

5.2.2.3.4. Total Sulphur

- Maximum Tariff Limit Criteria: 115 mg/m3
- Sample Mean: 2.46 mg/m3
- Sample Standard Deviation: 0.82 mg/m3
- Sample Standard Error: 0.41 mg/m3
- Degrees of Freedom: 3
- T-Multiple at 95% Confidence Interval: 3.182

95% Confident that the process mean is within the interval:
[1.15 mg/m3, 3.76 mg/m3]

Based on the analysis, the process mean for total sulphur in biomethane from LF3 will meet the tariff requirement with 100.00% probability.

5.2.2.3.5. Carbon Dioxide

- Maximum Tariff Limit Criteria: 2 Vol% ≈ 2 Mol%
- Sample Mean: 0.71 Mol%
- Sample Standard Deviation: 0.31 Mol%
- Sample Standard Error: 0.15Mol%
- Degrees of Freedom: 3
- T-Multiple at 95% Confidence Interval: 3.182

95% Confident that the process mean is within the interval: [0.23 Mol%, 1.20 Mol%]

Based on the analysis, the process mean for carbon dioxide in biomethane from LF3 will meet the tariff requirement with 99.83% probability.

5.2.2.3.6. Water Vapour

The gas samples were not analyzed for water vapour.

5.2.2.3.7. Oxygen

- Maximum Tariff Limit Criteria: 0.4 Vol% ≈ 0.4 Mol%

No statistical analysis is possible for oxygen in biomethane from LF3, as all samples were below the detection limit of 0.03 Mol %. It is observed that 0.03 Mol% is by an order of magnitude lower than the tariff upper limit of 0.4 Mol%.

5.2.2.3.8. Total Inerts

- Maximum Tariff Limit Criteria: 4 Mol%
- Sample Mean: 7.38 Mol%
- Sample Standard Deviation: 0.76 Mol%
- Sample Standard Error: 0.38 Mol%
- Degrees of Freedom: 3
- T-Multiple at 95% Confidence Interval: 3.182

95% Confident that the process mean is within the interval: [6.18 Mol%, 8.59 Mol%]

Based on the analysis, the process mean for total inerts in biomethane from LF3 will meet the tariff requirements with 0.15% probability. This result was expected, as the plant was designed for blending biomethane and natural gas prior to injection and the biomethane sample was taken prior to blending stage.

5.2.2.3.9. Butanes Plus

- Maximum Tariff Limit Criteria: 1.5 Mol%
- Sample Mean: 0.00070 Mol%
- Sample Standard Deviation: 0.00070 Mol%
- Sample Standard Error: 0.00035 Mol%
- Degrees of Freedom: 3
- T-Multiple at 95% Confidence Interval: 3.182

95% Confident that the process mean is within the interval: [0 Mol%, 0.0018 Mol%]

Based on the analysis, the process mean for butanes plus in biomethane from LF3 will meet the tariff requirement with 100.00% probability.

5.2.2.3.10. Conclusion – LF3 Biomethane Compliance to Tariff

Based on t-distribution analysis of the means of the tariff parameters for LF3 Biomethane, LF3 Biomethane will meet tariff requirements with 0.15% probability.

5.2.2.4. Biomethane from WWTP1

Table 8 provides a summary of the results of the statistical analysis for three biomethane samples from WWTP1. In Table 8, the columns "Lower Limit Mean" and "Upper Limit Mean" define a 95% Confidence Interval for the process mean. The column P(mean > TCPL LL) provides the probability that the process mean will be greater than the TCPL lower limit for that property/component. The column P(mean < TCPL UL) provides the probability that the process mean will be less than the TCPL upper limit for that property/component.

	Confidence Interval	Lower Limit Mean	Upper Limit Mean	P(mean > TCPL LL)	P(mean < TCPL UL)
WWTP_HHV(MJ/m3)	95%	37.48	37.65	99.99%	100.00%
WWTP_Wobbe (MJ/m3)	95%	49.96	50.39	99.99%	99.87%
WWTP_H2S (mg/m3)	95%	-0.80	1.13	NA	99.89%
WWTP_Total Sulphur (mg/m3)	95%	-0.75	1.07	NA	99.98%
WWTP_CO2 (Mole %)	95%	0.36%	0.83%	NA	99.93%
WWTP_O2 (Mole%)	95%	NA	NA	NA	NA
WWTP_Total Inerts (Mole%)	95%	0.36%	0.83%	NA	99.99%
WWTP_Butanes Plus (Mole %)	95%	NA	NA	NA	NA

Table 8 - Comparison of WWTP1 Biomethane to Pipeline Quality Gas Specifications

The following subsections outline each tariff component separately. The degrees of freedom are defined as *(n – 1)* where *n* is the number of samples that were above the detection limit for the corresponding property or component.

5.2.2.4.1. Gross Heating Value

- Minimum Tariff Limit Criteria: 36 MJ/m3
- Maximum Tariff Limit Criteria: 41.34 MJ/m3
- Sample Mean: 37.57 MJ/m3
- Sample Standard Deviation: 0.035 MJ/m3
- Sample Standard Error: 0.020 MJ/m3
- Degrees of Freedom: 2
- T-Multiple at 95% Confidence Interval: 4.303

95% Confident that the process mean is within the interval:
[37.48 MJ/m3, 37.65 MJ/m3]

Based on analysis, the process mean for gross heating value in biomethane from WWTP will meet the lower limit tariff requirement with 99.99% probability. The upper limit tariff requirement will be met with 100.00% probability.

5.2.2.4.2. Wobbe Index

- Minimum Tariff Limit Criteria: 47.23 MJ/m3
- Maximum Tariff Limit Criteria: 51.16 MJ/m3
- Sample Mean: 50.18 MJ/m3

- Sample Standard Deviation: 0.088 MJ/m3
- Sample Standard Error: 0.051 MJ/m3
- Degrees of Freedom: 2
- T-Multiple at 95% Confidence Interval: 4.303

95% Confident that the process mean is within the interval:
[49.96 MJ/m3, 50.39 MJ/m3]

Based on analysis, the process mean for Wobbe Index in biomethane from WWTP1 will meet the lower limit tariff requirement with 99.99% probability. The upper limit tariff requirement will be met with 99.87% probability.

5.2.2.4.3. Hydrogen Sulphide

- Maximum Tariff Limit Criteria: 23 mg/m3
- Sample Mean: 0.167 mg/m3
- Sample Standard Deviation: 0.10 mg/m3
- Sample Standard Error: 0.076 mg/m3
- Degrees of Freedom: 1
- T-Multiple at 95% Confidence Interval: 12.706

95% Confident that the process mean is within the interval: [0 mg/m3, 1.13 mg/m3]

Based on the analysis, the process mean for hydrogen sulphide in biomethane from WWTP1 will meet the tariff requirement with 99.89% probability.

5.2.2.4.4. Total Sulphur

- Maximum Tariff Limit Criteria: 115 mg/m3
- Sample Mean: 0.16 mg/m3
- Sample Standard Deviation: 0.10 mg/m3
- Sample Standard Error: 0.072 mg/m3
- Degrees of Freedom: 1
- T-Multiple at 95% Confidence Interval: 12.706

95% Confident that the process mean is within the interval: [0 mg/m3, 1.07 mg/m3]

Based on the analysis, the process mean for total sulphur in biomethane from WWTP1 will meet the tariff requirement with 99.98% probability.

5.2.2.4.5. Carbon Dioxide

- Maximum Tariff Limit Criteria: 2 Vol% ≈ 2 Mol%
- Sample Mean: 0.60 Mol%
- Sample Standard Deviation: 0.094 Mol%
- Sample Standard Error: 0.054 Mol%
- Degrees of Freedom: 2
- T-Multiple at 95% Confidence Interval: 4.303

95% Confident that the process mean is within the interval: [0.36 Mol%, 0.83 Mol%]

Based on the analysis, process mean for carbon dioxide in biomethane from WWTP1 will meet the tariff requirement with 99.93% probability.

5.2.2.4.6. Water Vapour

The gas samples were not analyzed for water vapour.

5.2.2.4.7. Oxygen

- Maximum Tariff Limit Criteria: 0.4 Vol% ≈ 0.4 Mol%

No statistical analysis is possible for oxygen in biomethane from WWTP1, as all samples were below the detection limit of 0.03 Mol %. It is observed that 0.03 Mol% is by an order of magnitude lower than the tariff upper limit of 0.4 Mol%.

5.2.2.4.8. Total Inerts

- Maximum Tariff Limit Criteria: 4 Mol%
- Sample Mean: 0.60 Mol%
- Sample Standard Deviation: 0.94 Mol%
- Sample Standard Error: 0.54 Mol%
- Degrees of Freedom: 2
- T-Multiple at 95% Confidence Interval: 4.303

95% Confident that the process mean is within the interval: [0.36 Mol%, 0.83 Mol%]

Based on the analysis, the process mean for total inerts in biomethane from WWTP1 will meet the tariff requirement with 99.99% probability.

5.2.2.4.9. Butanes Plus

- Maximum Tariff Limit Criteria: 1.5 Mol%

No statistical analysis is possible for Butanes Plus in biomethane from WWTP1, as all samples were below the detection limit of 0.002 Mol %. It is observed that, 0.002 Mol% is by 3 orders of magnitude below the tariff limit of 1.5 Mol%.

5.2.2.4.10. Conclusion – WWTP1 Biomethane Compliance to Tariff

Based on t-distribution analysis of the means of the tariff parameters for WWTP1 Biomethane, WWTP1 Biomethane will meet tariff requirements with 99.86% probability.

5.2.3 Qualifying Biomethane Production Sites for Direct Injection

For the purposes of further analysis, only those sites should be considered for direct injection that, at the very least, meet the requirement that, at a 95% confidence level, the process parameter means of biomethane production are within the tariff specifications. LF3 does not meet this requirement for Higher Heating Value, Wobbe Index, and Total Inerts. Regardless of that, Tier 2 analysis for LF3 will be analysed to ensure that all chemical contaminants are within acceptable concentrations as defined in the discussions in the sections below.

Figure 4 shows box plots that graphically represent the higher heating value (MJ/m3) for the sites: LF1, LF2, LF3, WWTP1, and NG. The line inside the box is at the median HHV. The bottom and top lines are at the first and third quartiles of HHV, Q1 and Q3. In order to draw the whiskers, two limits are calculated as follows:

Lower Limit: Q1 - 1.5(Q3-Q1)
Upper Limit: Q3 + 1.5(Q3-Q1)

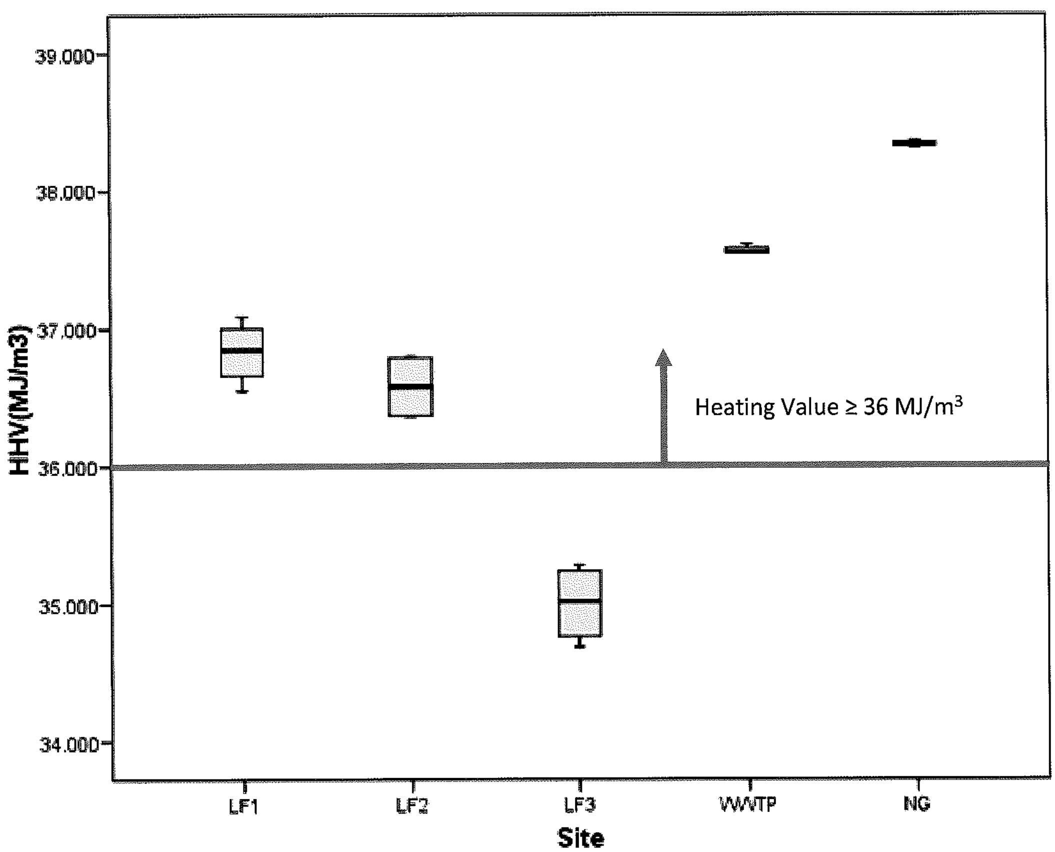

Figure 4 - Boxplot of HHV for LF1, LF2, LF3, WWTP1, and NG

From Figure 4, it is apparent that LF3 is not suitable for direct injection, as it is not probable that the higher heating value of the biomethane will meet pipeline quality requirements (HHV $\geq$ 36 MJ/m^3). In fact, the plant was designed for blending with Natural Gas prior to injection in order to attain interchangeability with the pipeline natural gas.

Figure 4 points to one more aspect of biomethane production that should be considered in the analysis – parameter variation. From comparison of the individual boxplots, it is apparent that there is more variation in the HHV of the biomethane from LF1, LF2 and LF3 as compared to the biomethane from WWTP1 and the natural gas samples NG. This variation could be attributed to differences in:

- Clean Up Process
  - Technology chosen and suppliers selected
  - Site construction and process implementation
  - Control strategy
- Biogas Composition Variation
  - to be further analyzed in the report
- Sampling Procedures
  - Personnel performing sampling/measurement
  - Timing of samples taken
    - LF1 samples – ½ in October 2008, ½ in February 2009
    - LF2 and LF3 samples – ½ in October 2008, ½ in November 2008
    - WWTP samples – All in November 2008
    - NG samples – All in December 2008
  - Differences introduced by transporting samples to the lab

In Section 5.3, variation due to the biogas composition and clean up process will be addressed. The contribution of differences in sampling procedure to the parameter variation is outside the scope of this report.

5.2.4 Trace Contaminants in Gas

Beyond the gas analysis completed for tariff compliance, gas analysis also addressed the presence of the following potential contaminants:

- Ammonia
- Extended Hydrocarbons
  - Cycloalkanes
  - Aromatics
  - Paraffins
- Organic Silicons, including Siloxanes
- TO-14 Halocarbons
- Mercury
- Volatile Metals
- Volatile Organic Compounds (VOCs)
- Semi-Volatile Organic Compounds (SVOCs)
- Pesticides
- Aldehydes and Ketones
- PCBs
- Biological Analysis
  - Detection of Live Bacteria Via Most Probable Number
  - Detection of Spores via NASA Protocol NHB 5340.1D mod
  - Total Bacteria and Corrosion-Causing Bacteria via Quantitative Polymerase Chain Reaction

Table 9 lists the contaminants found in biomethane and natural gas samples, but only highlighted compounds will be analyzed further, since these compounds were:

- Found in biomethane but not in natural gas
- Found in biomethane in equal or greater amounts than in natural gas samples

Biological results have not been subjected to statistical analysis, as comparison of these values would not allow for statistical interpretation. Biologicals are further discussed in Section 6.1.

Acceptable concentration levels for the highlighted contaminants are established later in the report.

Category	LF1 Biomethane	LF2 Biomethane	LF3 Biomethane	NG	WWTP1 Biomethane
Ammonia	BDL(<0.001%)	BDL(<0.001%)	BDL(<0.001%)	BDL(<0.001%)	BDL(<0.001%)
Extended Hydrocarbons					
-Cycloalkanes	BDL (< 1ppmv)	Cyclopentane; Methylcyclopentane; Cyclohexane	Cyclopentane; Methylcyclopentane; Cyclohexane; Methylcyclohexane	Cyclopentane; Methylcyclopentane; Cyclohexane; Methylcyclohexane	BDL (< 1ppmv)
-Aromatics	BDL (< 1ppmv)	BDL (< 1ppmv)	Benzene	Benzene; Toluene; Ethylbenzene; m,p-Xylene; o-Xylene; C3 Benzenes	BDL (< 1ppmv)
-Paraffins	Decanes	Hexanes	Hexanes; Heptanes	Hexanes; Heptanes; 2,2,4-Trimethylpentane; Octanes; Nonanes; Decanes	BDL (< 0.0001 mol%)
Organic Silicons*	Hexamethyldisilane; Octamethylcyclotetrasiloxane (D4)	BDL (< 0.5 ppmv Si)	BDL (< 0.5 ppmv Si)	BDL (< 0.5 ppmv Si)	BDL (< 0.5 ppmv Si)
TO-14 Halocarbons	Dichlorodifluoromethane (CFC-12)	Dichlorodifluoromethane (CFC-12); 1,2-Dichlorotetrafluoroethane (CFC-114); Trichlorofluoromethane (CFC-11); Chloroethane; Chloroethene (Vinyl Chloride);	Dichlorodifluoromethane (CFC-12); 1,2-Dichlorotetrafluoroethane (CFC-114); Trichlorofluoromethane (CFC-11); Chloroethane; Chloroethene (Vinyl Chloride);	BDL (< 0.1 ppmv)	BDL (< 0.1 ppmv)
Mercury	BDL (< 0.02 μg/m3)	BDL (< 0.02 μg/m3)	Yes**	BDL (< 0.02 μg/m3)	BDL (< 0.02 μg/m3)
Volatile Metals	Zinc	Zinc	BDL (< 30 μg/m3)	Zinc	Zinc
VOCs and SVOCs	Benzene; Carbon Tetrachloride; 1,2-Dichloropropane; Toluene; Ethylbenzene; m/p-Xylenes; 1,2,4-Trimethylbenzene;	Benzene; Carbon Tetrachloride; 1,2-Dichloropropane; Trichloroethene; Toluene; Ethylbenzene; m/p-Xylenes; o-Xylene; Isopropylbenzene; n-Propylbenzene; 1,3,5-Trimethylbenzene; 1,2,4-Trimethylbenzene; sec-Butylbenzene; 1,4-Dichlorobenzene; p-Isopropyltoluene; n-Butylbenzene; Naphthalene; 2-Methylnaphthalene; 1-Methylnaphthalene; Diethylphthalate; Di-n-butylphthalate;	Benzene; Carbon Tetrachloride; 1,2-Dichloropropane; Trichloroethene; Toluene; Tetrachloroethene; p-Isopropyltoluene; Diethylphthalate; Di-n-butylphthalate	Benzene; Carbon Tetrachloride; Toluene; Dibromochloromethane; Ethylbenzene; m/p-Xylenes; o-Xylene; Isopropylbenzene; n-Propylbenzene; 1,3,5-Trimethylbenzene; 1,2,4-Trimethylbenzene; sec-Butylbenzene; p-Isopropyltoluene; Benzyl Alcohol; n-Butylbenzene; Nitrobenzene; Naphthalene; 2-Methylnaphthalene; 1-Methylnaphthalene; Di-n-butylphthalate	Benzene; Carbon Tetrachloride; Toluene; Ethylbenzene; m/p-Xylenes; o-Xylene; 1,1,2,2-Tetrachloroethane; n-Propylbenzene; 1,3,5-Trimethylbenzene; sec-Butylbenzene; 1,4-Dichlorobenzene; p-Isopropyltoluene; n-Butylbenzene; Naphthalene; 2-Methylnaphthalene; 1-Methylnaphthalene; 4-Nitrophenol; Di-n-butylphthalate; bis(2-Ethylhexyl)phthalate

Category	LF1 Biomethane	LF2 Biomethane	LF3 Biomethane	NG	WWTP1 Biomethane
Pesticides	BDL (varies)	BDL (varies)	4,4'-DDT	BDL (varies)	4,4'-DDT
Aldehydes and Ketones	Formaldehyde; Acetaldehyde; Acetone; Acrolein; 2-Butanone; Methacrolein; Butanal; Benzaldehyde	Formaldehyde; Acetaldehyde; Acetone; Propionaldehyde; Crotonaldehyde; 2-Butanone; Methacrolein; Butanal; Benzaldehyde	Formaldehyde; Acetaldehyde; Acetone; Propionaldehyde; 2-Butanone; Butanal	Formaldehyde; Acetaldehyde; Acetone; Propionaldehyde; 2-Butanone; Methacrolein; Butanal; Benzaldehyde; Pentanal	Acetaldehyde; Acetone
PCBs	BDL (varies)	BDL (varies)	BDL (varies)	BDL (varies)	BDL (varies)
Live Bacteria					
-Aerobic	Yes	No growth detected	No growth detected	Yes	Yes
-Anaerobic	No growth detected	No growth detected	Yes	Yes	Yes
Spores					
-Aerobic	No growth detected	No growth detected	No growth detected	No growth detected	Yes
-Anaerobic	No growth detected	No growth detected	Yes	Yes	Yes
Total Bacteria					
-Total	Yes	Yes	Yes	Yes	Yes
-Total Acid Producing	Yes	Yes	Yes	Yes	Yes
-Total Iron Oxidizing	Yes	BDL	Yes	Yes	Yes
-Total Sulfate-Reducing	BDL	BDL	BDL	BDL	BDL

Table 9 - Summary of Contaminants Detected in Biomethane and Natural Gas Samples

*Statistical analysis has not been performed on siloxanes

**It is noted that mercury was found in biomethane and not biogas on 1st visit to LF3, and mercury was found in biogas and not biomethane on 2nd visit to LF3. No explanation has been provided for this apparent discrepancy.

5.2.5 Analysis of Trace Contaminants Compliance with Exposure Limiting Values

In order to determine the probability that trace contaminants would be below exposure limiting values, statistical analysis was completed on gas samples from all sites. It is assumed that the concentration of contaminants are the output of a random process and falling within +/-3σ (σ is standard deviation) of the process parameter mean, resulting in a normal distribution. Given the small sample size, t-distribution analysis was utilized to make inferences about the processes.

Each subsection contains a table which includes all values for that contaminant from all sites, including BDL. The rows "LL Mean @ CI Default" and "UL Mean @ CI Default" define a 95% Confidence Interval for the process mean of concentration for the corresponding compound. The row "P(mean < x)" lists the probability that the process mean will be less than the identified exposure limiting value.

In the analysis below, sample size is defined only by those samples that were above the detection limit for the corresponding contaminant.

5.2.5.1. TO-14 Halocarbons

Of the 31 T0-14 Halocarbons which were analyzed, 5 meet the criteria for further analysis:

- Dichlorodifluoromethane (CFC-12)
- 1,2-Dichlorotetrafluoroethane (CFC-114)
- Trichlorofluoromethane (CFC-11)
- Chloroethane
- Chloroethene (Vinyl Chloride)

5.2.5.1.1. Dichlorodifluoromethane (CFC-12)

OH&SA Time Weighted Average Exposure Value (TWAEV): 1000 ppm

CFC-12 was detected in biomethane samples from LF1, LF2 and LF3. Based on the analysis, the process mean for concentration of dichlorodifluoromethane in biomethane from LF1, LF2 and LF3 will be less than the OH&SA TWAEV with 100.00% probability.

Site	LF1_CFC-12 (ppmv)	LF2_CFC-12 (ppmv)	LF3_CFC-12 (ppmv)	NG_CFC-12 (ppmv)	WWTP_CFC-12 (ppmv)
Value 1	3.24033436	2.51	3.51	BDL	~~BDL~~
Value 2	2.59000000	2.52	3.60	BDL	BDL
Value 3	1.34523027	2.37	2.96	~~BDL~~	BDL
Value 4	1.36423143	2.34	2.98	BDL	BDL
OH&SA TWAEV (ppm)	1,000	1,000	1,000	1,000	1,000
sample size	4	4	4	NA	NA
mean	2.13	2.43	3.26	NA	NA
std dev	0.939	0.094	0.34	NA	NA
std error	0.470	0.047	0.17	NA	NA
Default Confidence Interval	95%	95%	95%	NA	NA
T Multiple	3.18	3.18	3.18	NA	NA
LL mean @ CI default	0.64	2.28	2.72	NA	NA
UL mean @ CI default	3.63	2.58	3.80	NA	NA
P(mean < OH&SA TWAEV)	100.00%	100.00%	100.00%	NA	NA

Table 10 - Comparison of CFC-12 Levels to OH&SA TWAEV

5.2.5.1.2. 1,2-Dichlorotetrafluoroethane (CFC-114)

OH&SA Time Weighted Average Exposure Value (TWAEV): 1000 ppm

CFC-114 was detected in biomethane samples from LF2 and LF3. Based on the analysis, the process mean for concentration of1,2-Dichlorotetrafluoroethane in biomethane from LF2 and LF3 will be less than the OH&SA TWAEV with 100.00% probability.

Site	LF1_CFC-114 (ppmv)	LF2_CFC-114 (ppmv)	LF3_CFC-114 (ppmv)	NG_CFC-114 (ppmv)	WWTP_CFC-114 (ppmv)
Value 1	BDL	0.11	0.13	BDL	~~BDL~~
Value 2	BDL	0.11	0.12	BDL	BDL
Value 3	BDL	BDL	0.17	~~BDL~~	BDL
Value 4	BDL	BDL	0.17	BDL	BDL
OH&SA Exposure Limit (ppm)	1,000	1,000	1,000	1,000	1,000
sample size	NA	2	4	NA	NA
mean	NA	0.11	0.15	NA	NA
std dev	NA	0.00055	0.022	NA	NA
std error	NA	0.00039	0.011	NA	NA
Default Confidence Interval	NA	95%	95%	NA	NA
T Multiple	NA	12.71	3.18	NA	NA
LL mean @ CI default	NA	0.11	0.11	NA	NA
UL mean @ CI default	NA	0.12	0.18	NA	NA
P(mean < OH&SA TWAEV)	NA	100.00%	100.00%	NA	NA

Table 11 - Comparison of CFC-114 Levels to OH&SA TWAEV

5.2.5.1.3. Trichlorofluoromethane (CFC-11)

OH&SA Ceiling Exposure Value (CEV): 1000 ppm

CFC-11 was detected in biomethane samples from LF2 and LF3. Based on the analysis, the process mean for concentration of Trichlorofluoromethane in biomethane from LF2 and LF3 will be less than the OH&SA CEV with 100.00% probability.

Site	LF1_CFC-11 (ppmv)	LF2_CFC-11 (ppmv)	LF3_CFC-11 (ppmv)	NG_CFC-11 (ppmv)	WWTP_CFC-11 (ppmv)
Value 1	BDL	0.15	0.13	BDL	~~BDL~~
Value 2	BDL	0.16	0.13	BDL	BDL
Value 3	BDL	BDL	0.23	~~BDL~~	BDL
Value 4	BDL	BDL	0.24	BDL	BDL
OH&SA CEV (ppm)	1,000	1,000	1,000	1,000	1,000
sample size	NA	2	4	NA	NA
mean	NA	0.16	0.18	NA	NA
std dev	NA	0.0065	0.058	NA	NA
std error	NA	0.0046	0.029	NA	NA
Default Confidence Interval	NA	95%	95%	NA	NA
T Multiple	NA	12.71	3.18	NA	NA
LL mean @ CI default	NA	0.10	0.09	NA	NA
UL mean @ CI default	NA	0.22	0.28	NA	NA
P(mean < OH&SA CEV)	NA	100.00%	100.00%	NA	NA

Table 12 - Comparison of CFC-11 Levels to OH&SA CEV

5.2.5.1.4. Chloroethane

OH&SA Time Weighted Average Exposure Value (CEV): 100 ppm

Chloroethane was detected in biomethane samples from LF2 and LF3. Based on the analysis, the process mean for concentration of Chloroethane in biomethane from LF2 and LF3 will be less than the OH&SA TWAEV with 100.00% probability.

Site	LF1_Chloroethane (ppmv)	LF2_Chloroethane (ppmv)	LF3_Chloroethane (ppmv)	NG_Chloroethane (ppmv)	WWTP_Chloroethane (ppmv)
Value 1	BDL	0.61	0.55	BDL	~~BDL~~
Value 2	BDL	0.62	0.56	BDL	BDL
Value 3	BDL	0.42	0.64	~~BDL~~	BDL
Value 4	BDL	0.41	0.66	BDL	BDL
OH&SA TWAEV (ppm)	100	100	100	100	100
sample size	NA	4	4	NA	NA
mean	NA	0.52	0.61	NA	NA
std dev	NA	0.11	0.056	NA	NA
std error	NA	0.057	0.028	NA	NA
Default Confidence Interval	NA	95%	95%	NA	NA
T Multiple	NA	3.18	3.18	NA	NA
LL mean @ CI default	NA	0.34	0.52	NA	NA
UL mean @ CI default	NA	0.70	0.69	NA	NA
P(mean < OH&SA TWAEV)	NA	100.00%	100.00%	NA	NA

Table 13 - Comparison of Chloroethane Levels to OH&SA TWAEV

5.2.5.1.5. Chloroethene (Vinyl Chloride)

OSHA Time Weighted Average PEL (TWA): 1 ppm

Chloroethene was detected in biomethane samples from LF2 and LF3. Based on the analysis, the process mean for concentration of chlorethene in biomethane from LF2 will be less than the OSHA TWA PEL with 100.00% probability. Based on the analysis, the process mean for concentration of chlorethene in biomethane from LF3 will be less than the OSHA TWA PEL with 99.99% probability.

Site	LF1_Vinyl Chloride (ppmv)	LF2_Vinyl Chloride (ppmv)	LF3_Vinyl Chloride (ppmv)	NG_Vinyl Chloride (ppmv)	WWTP_Vinyl Chloride (ppmv)
Value 1	BDL	0.33	0.23	BDL	~~BDL~~
Value 2	BDL	0.33	0.25	BDL	BDL
Value 3	BDL	0.25	0.15	~~BDL~~	BDL
Value 4	BDL	0.25	0.13	BDL	BDL
OSHA TWA (ppm)	1	1	1	1	1
sample size	NA	4	4	NA	NA
mean	NA	0.289	0.190	NA	NA
std dev	NA	0.04665	0.058	NA	NA
std error	NA	0.02333	0.029	NA	NA
Default Confidence Interval	NA	95%	95%	NA	NA
T Multiple	NA	3.18	3.18	NA	NA
LL mean @ CI default	NA	0.21	0.10	NA	NA
UL mean @ CI default	NA	0.36	0.28	NA	NA
P(mean < OSHA TWA)	NA	100.00%	99.99%	NA	NA

Table 14 - Comparison of Chloroethene Levels to OSHA TWA

5.2.5.1.6. Conclusion – Analysis of TO-14 Halocarbons

Based on t-distribution analysis, the process means of concentrations of the 5 Halocarbons analyzed will be less than their respective limiting values with ≥99.99% probability.

5.2.5.2. VOCs and SVOCs

Of the 115 VOCs and SVOCs which were analyzed, 12 meet the criteria for further analysis:

- Benzene
- Carbon Tetrachloride
- 1,2-Dichloropropane
- Trichloroethene
- Tetrachloroethene
- 1,1,2,2-Tetrachloroethane
- 1,4-Dichlorobenzene
- p-Isopropyltoluene
- Naphthalene
- Diethylphthalate
- Di-n-butylphthalate
- bis(2-Ethylhexyl)phthalate

5.2.5.2.1. Benzene

OH&SA Time Weighted Average Exposure Value (TWAEV): 0.5 ppm

Benzene was detected in biomethane samples from all sites, and in natural gas samples. Based on the analysis, the process mean for concentration of benzene in biomethane from LF1, LF2, LF3, and WWTP1 and natural gas will be less than the OH&SA TWAEV with 100.00% probability.

Site	LF1_Benzene (ppbv)	LF2_Benzene (ppbv)	LF3_Benzene (ppbv)	NG_Benzene (ppbv)	WWTP1_Benzene (ppbv)
Value 1	0.74	0.69	12.29	12.18	0.61
Value 2	0.73	0.78	14.30	8.68	0.83
Value 3	0.046	1.27	0.64	5.42	0.67
Value 4	BDL	6.24	0.60	13.63	BDL
OH&SA TWAEV (ppb)	500	500	500	500	500
sample size	3	4	4	4	3
mean	0.50	2.24	6.96	9.98	0.70
std dev	0.40	2.67	7.36	3.68	0.11
std error	0.23	1.34	3.68	1.84	0.07
Default Confidence Interval	95%	95%	95%	95%	95%
T Multiple	4.30	3.18	3.18	3.18	4.30
LL mean @ CI default	-0.48	-2.01	-4.76	4.12	0.42
UL mean @ CI default	1.49	6.50	18.67	15.83	0.98
P(mean < OH&SA TWAEV)	100.00%	100.00%	100.00%	100.00%	100.00%

Table 15 - Comparison of Benzene Levels to OH&SA TWAEV

5.2.5.2.2. Carbon Tetrachloride

OH&SA Time Weighted Average Exposure Value (TWAEV): 2 ppm

Carbon Tetrachloride was detected in biomethane samples from all sites, and in the natural gas samples. Based on the analysis, the process mean for concentration of carbon tetrachloride in biomethane from LF1, LF2, LF3, and WWTP1 and natural gas is less than the OH&SA TWAEV with 100.00% probability.

Site	LF1_Carbon Tetrachloride (ppbv)	LF2_Carbon Tetrachloride (ppbv)	LF3_Carbon Tetrachloride (ppbv)	NG_Carbon Tetrachloride (ppbv)	WWTP1_Carbon Tetrachloride (ppbv)
Value 1	0.50	0.79	0.54	0.94	BDL
Value 2	0.37	0.80	0.64	0.50	0.31
Value 3	BDL	BDL	BDL	0.49	BDL
Value 4	BDL	BDL	0.29	0.45	-
OH&SA TWAEV (ppb)	2,000	2,000	2,000	2,000	2,000
sample size	2	2	3	4	1
mean	0.43	0.80	0.49	0.59	NA
std dev	0.09	0.007	0.18	0.23	NA
std error	0.06	0.005	0.10	0.11	NA
Default Confidence Interval	95%	95%	95%	95%	NA
T Multiple	12.71	12.71	4.30	3.18	NA
LL mean @ CI default	-0.35	0.73	0.046	0.23	NA
UL mean @ CI default	1.22	0.86	0.93	0.96	NA
P(mean < OH&SA TWAEV)	100.00%	100.00%	100.00%	100%	NA

Table 16 - Comparison of Carbon Tetrachloride Levels to OH&SA TWAEV

5.2.5.2.3. 1,2-Dichloropropane

OH&SA Time Weighted Average Exposure Value (TWAEV): 10 ppm

1,2-Dichloropropane was detected in biomethane samples from LF1, LF2 and LF3. Based on the analysis, the process mean for concentration of 1,2-Dichloropropane in biomethane from LF3 is less than the OH&SA TWAEV with 100.00% probability. For LF1 and LF2, only one sample was found to contain trace amounts of 1,2-Dichloropropane, 19.68 ppbv and 0.514 ppbv respectively, noticeably below the OH&SA TWAEV limit of 10,000 ppb.

Site	LF1_1,2-Dichloropropane (ppbv)	LF2_1,2-Dichloropropane (ppbv)	LF3_1,2-Dichloropropane (ppbv)	NG_1,2-Dichloropropane (ppbv)	WWTP1_1,2-Dichloropropane (ppbv)
Value 1	19.68	BDL	0.76	BDL	BDL
Value 2	BDL	BDL	0.79	BDL	BDL
Value 3	BDL	BDL	BDL	BDL	BDL
Value 4	BDL	0.51	BDL	BDL	-
OH&SA TWAEV (ppb)	10,000	10,000	10,000	10,000	10,000
sample size	1	1	2	NA	NA
mean	19.68	NA	0.777	NA	NA
std dev	NA	NA	0.021	NA	NA
std error	NA	NA	0.015	NA	NA
Default Confidence Interval	95%	NA	95%	NA	NA
T Multiple	NA	NA	12.71	NA	NA
LL mean @ CI default	NA	NA	0.59	NA	NA
UL mean @ CI default	NA	NA	0.96	NA	NA
P(mean < OH&SA TWAEV)	NA	NA	100.00%	NA	NA

Table 17 - Comparison of 1,2-Dichloropropane Levels to OH&SA TWAEV

5.2.5.2.4. Trichloroethene

OH&SA Time Weighted Average Exposure Value (TWAEV): 10 ppm

Trichloroethene was detected in biomethane samples from LF2 and LF3. Based on the analysis, the process mean for concentration of trichloroethene in biomethane from LF3 is less than the OH&SA TWAEV with 100.00% probability. For LF2, only one sample was found to contain trace amounts of Trichloroethene, 0.602 ppbv, noticeably below the OH&SA TWAEV limit of 10,000 ppb.

Site	LF1_Trichloroethene (ppbv)	LF2_Trichloroethene (ppbv)	LF3_Trichloroethene (ppbv)	NG_Trichloroethene (ppbv)	WWTP1_Trichloroethene (ppbv)
Value 1	BDL	BDL	1.26	BDL	BDL
Value 2	BDL	BDL	1.48	BDL	BDL
Value 3	BDL	BDL	BDL	BDL	BDL
Value 4	BDL	0.60	BDL	BDL	-
OH&SA TWAEV (ppb)	10,000	10,000	10,000	10,000	10,000
sample size	NA	1	2	NA	NA
mean	NA	NA	1.37	NA	NA
std dev	NA	NA	0.15	NA	NA
std error	NA	NA	0.11	NA	NA
Default Confidence Interval	NA	NA	95%	NA	NA
T Multiple	NA	NA	12.71	NA	NA
LL mean @ CI default	NA	NA	(0.01)	NA	NA
UL mean @ CI default	NA	NA	2.75	NA	NA
P(mean < OH&SA TWAEV)	NA	NA	100.00%	NA	NA

Table 18 - Comparison of Trichloroethene Levels to OH&SA TWAEV

5.2.5.2.5. Tetrachloroethene

OH&SA Time Weighted Average Exposure Value (TWAEV): 10 ppm

Tetrachloroethene was detected in biomethane samples from LF3. Based on the analysis, the process mean for concentration of tetrachloroethene in biomethane from LF3 is less than the OH&SA TWAEV with 100.00% probability.

Site	LF1_Tetrachloroethene (ppbv)	LF2_Tetrachloroethene (ppbv)	LF3_Tetrachloroethene (ppbv)	NG_Tetrachloroethene (ppbv)	WWTP1_Tetrachloroethene (ppbv)
Value 1	BDL	BDL	BDL	BDL	BDL
Value 2	BDL	BDL	BDL	BDL	BDL
Value 3	BDL	BDL	0.48	BDL	BDL
Value 4	BDL	BDL	0.47	BDL	-
OH&SA TWAEV (ppb)	25,000	25,000	25,000	25,000	25,000
sample size	NA	NA	2	NA	NA
mean	NA	NA	0.475	NA	NA
std dev	NA	NA	0.0038	NA	NA
std error	NA	NA	0.0027	NA	NA
Default Confidence Interval	NA	NA	95%	NA	NA
T Multiple	NA	NA	12.71	NA	NA
LL mean @ CI default	NA	NA	0.44	NA	NA
UL mean @ CI default	NA	NA	0.51	NA	NA
P(mean < OH&SA TWAEV)	NA	NA	100.00%	NA	NA

Table 19 - Comparison of Tetrachloroethene Levels to OH&SA TWAEV

5.2.5.2.6. 1,1,2,2-Tetrachloroethane

OH&SA Time Weighted Average Exposure Value (TWAEV): 1 ppm

1,1,2,2-Tetrachloroethane was detected in biomethane samples from WWTP1. Based on the analysis, the process mean for concentration of 1,1,2,2-Tetrachloroethane in biomethane from WWTP1 will be less than the OH&SA TWAEV with 100.00% probability.

Site	LF1_1,1,2,2-Tetrachloroethane (ppbv)	LF2_1,1,2,2-Tetrachloroethane (ppbv)	LF3_1,1,2,2-Tetrachloroethane (ppbv)	NG_1,1,2,2-Tetrachloroethane (ppbv)	WWTP1_1,1,2,2-Tetrachloroethane (ppbv)
Value 1	BDL	BDL	BDL	BDL	BDL
Value 2	BDL	BDL	BDL	BDL	0.42
Value 3	BDL	BDL	BDL	BDL	0.47
Value 4	BDL	BDL	BDL	BDL	-
OH&SA TWAEV (ppb)	1,000	1,000	1,000	1,000	1,000
sample size	NA	NA	NA	NA	2
mean	NA	NA	NA	NA	0.44
std dev	NA	NA	NA	NA	0.03
std error	NA	NA	NA	NA	0.02
Default Confidence Interval	NA	NA	NA	NA	95%
T Multiple	NA	NA	NA	NA	12.71
LL mean @ CI default	NA	NA	NA	NA	0.16
UL mean @ CI default	NA	NA	NA	NA	0.73
P(mean < OH&SA TWAEV)	NA	NA	NA	NA	100%

Table 20 - Comparison of 1,1,2,2-Tetrachloroethane Levels to OH&SA TWAEV

5.2.5.2.7. 1,4-Dichlorobenzene

OH&SA Time Weighted Average Exposure Value (TWAEV): 10 ppm

1,4-Dichlorobenzene was detected in biomethane samples from LF2. Based on the analysis, the process mean for concentration of 1,4-Dichlorobenzene in biomethane from LF2 is less than the OH&SA TWAEV with 100.00% probability.

Site	LF1_1,4-Dichlorobenzene (ppbv)	LF2_1,4-Dichlorobenzene (ppbv)	LF3_1,4-Dichlorobenzene (ppbv)	NG_1,4-Dichlorobenzene (ppbv)	WWTP1_1,4-Dichlorobenzene (ppbv)
Value 1	BDL	BDL	BDL	BDL	BDL
Value 2	BDL	BDL	BDL	BDL	BDL
Value 3	BDL	1.98	BDL	BDL	BDL
Value 4	BDL	0.41	BDL	BDL	-
OH&SA TWAEV (ppb)	10,000	10,000	10,000	10,000	10,000
sample size	NA	2	NA	NA	NA
mean	NA	1.19	NA	NA	NA
std dev	NA	1.11	NA	NA	NA
std error	NA	0.79	NA	NA	NA
Default Confidence Interval	NA	95%	NA	NA	NA
T Multiple	NA	12.71	NA	NA	NA
LL mean @ CI default	NA	(8.80)	NA	NA	NA
UL mean @ CI default	NA	11.19	NA	NA	NA
P(mean < OH&SA TWAEV)	NA	100.00%	NA	NA	NA

Table 21 - Comparison of 1,4-Dichlorobenzene Levels to OH&SA TWAEV

5.2.5.2.8. p-Isopropyltoluene

There is no exposure limit for p-Isopropyltoluene in OH&SA, OSHA, or NIOSH. p-Isopropyltoluene was found in all samples except LF1.

Site	LF1_p-Isopropyltoluene (ppbv)	LF2_p-Isopropyltoluene (ppbv)	LF3_p-Isopropyltoluene (ppbv)	NG_p-Isopropyltoluene (ppbv)	WWTP1_p-Isopropyltoluene (ppbv)
Value 1	BDL	BDL	BDL	17.12	BDL
Value 2	BDL	BDL	0.45	11.16	0.40
Value 3	BDL	20.49	BDL	18.21	0.40
Value 4	BDL	6.66	BDL	13.61	-
No Exposure Limit (OH&SA, OSHA, or NIOSH)					
sample size	NA	2	1	4	2
mean	NA	13.57	NA	15.03	0.40
std dev	NA	9.78	NA	3.24	0.00
std error	NA	6.92	NA	1.62	0.00
Default Confidence Interval	NA	95%	NA	95%	95%
T Multiple	NA	12.71	NA	3.18	12.71
LL mean @ CI default	NA	(74.30)	NA	9.87	0.40
UL mean @ CI default	NA	101.45	NA	20.18	0.41

Table 22 - Comparison of p-Isopropyltoluene Levels

5.2.5.2.9. Naphthalene

OH&SA Time Weighted Average Exposure Value (TWAEV): 10 ppm

Naphthalene was detected in biomethane samples from LF2 and in NG samples. Based on the analysis, the process mean for naphthalene in biomethane from LF2 and in NG is less than the OH&SA TWAEV with 100.00% probability.

Site	LF1_Naphthalene (ppbv)	LF2_Naphthalene (ppbv)	LF3_Naphthalene (ppbv)	NG_Naphthalene (ppbv)	WWTP1_Naphthalene (ppbv)
Value 1	BDL	BDL	BDL	8.03	BDL
Value 2	BDL	BDL	BDL	7.90	BDL
Value 3	BDL	7.00	BDL	4.53	BDL
Value 4	BDL	3.69	BDL	3.13	-

OH&SA TWAEV (ppb)	10,000	10,000	10,000	10,000	10,000
sample size	NA	2	NA	4	NA
mean	NA	5.349	NA	5.90	NA
std dev	NA	2.34206	NA	2.46	NA
std error	NA	1.65608	NA	1.23	NA
Default Confidence Interval	NA	95%	NA	95%	NA
T Multiple	NA	12.71	NA	3.18	NA
LL mean @ CI default	NA	(15.69)	NA	1.99	NA
UL mean @ CI default	NA	26.39	NA	9.81	NA
P(mean < OH&SA TWAEV)	NA	99.99%	NA	100.00%	NA

Table 23 - Comparison of Naphthalene Levels to OH&SA TWAEV

5.2.5.2.10. Diethylphthalate

OH&SA Time Weighted Average Exposure Value (TWAEV): 10 ppm

Diethylphthalate was detected in one biomethane sample from LF2 and one biomethane sample from LF3. Both values detected, 0.500 ppbv and 0.546 ppbv, are noticeably below the OH&SA TWAEV of 5000 ppb.

Site	LF1_Diethylphthalate (ppbv)	LF2_Diethylphthalate (ppbv)	LF3_Diethylphthalate (ppbv)	NG_Diethylphthalate (ppbv)	WWTP1_Diethylphthalate (ppbv)
Value 1	BDL	BDL	0.545806829	BDL	BDL
Value 2	BDL	0.500	BDL	BDL	BDL
Value 3	BDL	BDL	BDL	BDL	BDL
Value 4	BDL	BDL	BDL	BDL	-

OH&SA TWAEV (ppb)	5,000	5,000	5,000	5,000	5,000
sample size	NA	1	1	NA	NA
mean	NA	NA	NA	NA	NA
std dev	NA	NA	NA	NA	NA
std error	NA	NA	NA	NA	NA
Default Confidence Interval	NA	NA	NA	NA	NA
T Multiple	NA	NA	NA	NA	NA
LL mean @ CI default	NA	NA	NA	NA	NA
UL mean @ CI default	NA	NA	NA	NA	NA
P(mean < OH&SA TWAEV)	NA	NA	NA	NA	NA

Table 24 - Comparison of Diethylphthalate Levels to OH&SA TWAEV

5.2.5.2.11. Di-n-butylphthalate

OH&SA Time Weighted Average Exposure Value (TWAEV): 5 mg/m3
Molecular Weight Di-n-butylphthalate: 278.34 g/mol
OH&SA TWAEV at STP: 408 ppb

Di-n-butylphthalate was detected in at least one biomethane sample from LF2, LF3, and WWTP1, and in two NG samples. Based on the analysis, the process mean for concentration of di-n-butylphthalate in biomethane from LF2 and LF3 and in NG is less than the OH&SA TWAEV with 100.00% probability. Di-n-butylphthalate was detected at a level of 0.539 ppbv in one sample from WWTP1, which is 3 orders of magnitude lower than the OH&SA TWAEV of 408 ppb.

Site	LF1_Di-n-butylphthalate (ppbv)	LF2_Di-n-butylphthalate (ppbv)	LF3_Di-n-butylphthalate (ppbv)	NG_Di-n-butylphthalate (ppbv)	WWTP1_Di-n-butylphthalate (ppbv)
Value 1	BDL	BDL	1.81	BDL	BDL
Value 2	BDL	1.12	0.37	BDL	BDL
Value 3	BDL	0.48	0.36	1.0	0.538517492
Value 4	BDL	0.59	0.49	0.913	-
OH&SA TWAEV (ppb)	408	408	408	408	408
sample size	NA	3	4	2	1
mean	NA	0.73	0.76	0.96	NA
std dev	NA	0.34	0.70	0.06	NA
std error	NA	0.20	0.35	0.05	NA
Default Confidence Interval	NA	95%	95%	95%	NA
T Multiple	NA	4.30	3.18	12.71	NA
LL mean @ CI default	NA	(0.11)	(0.36)	0.38	NA
UL mean @ CI default	NA	1.57	1.88	1.53	NA
P(mean < OH&SA TWAEV)	NA	100.00%	100.00%	100.00%	NA

Table 25 - Comparison of Di-n-butylphthalate Levels to OH&SA TWAEV

5.2.5.2.12. bis(2-Ethylhexyl)phthalate

OH&SA Time Weighted Average Exposure Value (TWAEV): 3 mg/m3
Molecular Weight bis(2-Ethylhexyl)phthalate: 390.56 g/mol
OH&SA TWAEV at STP: 174 ppb

bis(2-Ethylhexyl)phthalate was detected in one biomethane sample from WWTP1. bis(2-Ethylhexyl)phthalate was detected at a level of 6.10 ppbv in one sample from WWTP1, which is noticeably lower than the OH&SA TWAEV of 174 ppb.

Site	LF1_bis(2-Ethylhexyl)phthalate (ppbv)	LF2_bis(2-Ethylhexyl)phthalate (ppbv)	LF3_bis(2-Ethylhexyl)phthalate (ppbv)	NG_bis(2-Ethylhexyl)phthalate (ppbv)	WWTP1_bis(2-Ethylhexyl)phthalate (ppbv)
Value 1	BDL	BDL	BDL	BDL	BDL
Value 2	BDL	BDL	BDL	BDL	BDL
Value 3	BDL	BDL	BDL	BDL	6.10
Value 4	BDL	BDL	BDL	BDL	-
OH&SA TWAEV (ppb)	174	174	174	174	174
sample size	NA	NA	NA	NA	1
mean	NA	NA	NA	NA	NA
std dev	NA	NA	NA	NA	NA
std error	NA	NA	NA	NA	NA
Default Confidence Interval	NA	NA	NA	NA	NA
T Multiple	NA	NA	NA	NA	NA
LL mean @ CI default	NA	NA	NA	NA	NA
UL mean @ CI default	NA	NA	NA	NA	NA
P(mean < OH&SA TWAEV)	NA	NA	NA	NA	NA

Table 26 - Comparison of bis(2-Ethylhexyl)phthalate Levels to OH&SA TWAEV

5.2.5.2.13. Conclusion – Analysis of VOCs and SVOCs

Based on t-distribution analysis, the process mean of concentrations of the 12 VOCs and SVOCs analyzed will be less than their respective limiting values with ≥99.99% probability, excluding p-Isopropyltoluene. There is no published exposure limiting value for p-Isopropyltoluene.

5.2.5.3. Pesticides

All pesticides which were tested were below detection limit in the samples, except for 4-4'-DDT which was found in biomethane samples from LF3 and WWTP1.

5.2.5.3.1. 4,4'-DDT

OH&SA Time Weighted Average Exposure Value (TWAEV): 1 mg/m3
Molecular Weight 4,4'-DDT: 354.49 g/mol
OH&SA TWAEV at STP: 64 ppb

4,4'-DDT was detected in biomethane samples from LF3 and WWTP1. Based on the analysis, the process mean for concentration of 4,4'-DDT in biomethane from WWTP1 is less than the OH&SA TWAEV with 100.00% probability. Only one sample from LF3 was found to contain 4,4'-DDT at a concentration of 0.0025 ppbv, 4 orders of magnitude below the OH&SA TWAEV of 64 ppb.

Site	LF1_4,4'-DDT (ppbv)	LF2_4,4'-DDT (ppbv)	LF3_4,4'-DDT (ppbv)	NG_4,4'-DDT (ppbv)	WWTP1_4,4'-DDT (ppbv)
Value 1	BDL	BDL	BDL	BDL	0.0063
Value 2	BDL	BDL	BDL	BDL	0.0034
Value 3	BDL	BDL	BDL	BDL	BDL
Value 4	BDL	BDL	0.0025	BDL	-
OH&SA TWAEV (ppb)	64	64	64	64	64
sample size	NA	NA	1	NA	2
mean	NA	NA	NA	NA	0.0049
std dev	NA	NA	NA	NA	0.0021
std error	NA	NA	NA	NA	0.0015
Default Confidence Interval	NA	NA	NA	NA	95%
T Multiple	NA	NA	NA	NA	12.71
LL mean @ CI default	NA	NA	NA	NA	-0.014
UL mean @ CI default	NA	NA	NA	NA	0.023
P(mean < OH&SA TWAEV)	NA	NA	NA	NA	100.00%

Table 27 - Comparison of 4,4'-DDT Levels to OH&SA TWAEV

5.2.5.3.2. Conclusion – Analysis of Pesticides

Based on t-distribution analysis, the process mean concentration of one pesticide analyzed will be less than its limiting value with 100.00% probability.

5.2.5.4. Aldehydes and Ketones

Of the 13 aldehydes and ketones which were analyzed, 6 meet the criteria for further analysis:

- Acetone
- Acrolein
- Propionaldehyde
- Crotonaldehyde
- 2-Butanone
- Butanal

5.2.5.4.1. Acetone

OH&SA Time Weighted Average Exposure Value (TWAEV): 500 ppm

Acetone was detected in biomethane samples from LF1, LF2, LF3 and WWTP1, and in NG samples. Based on the analysis, the process mean for concentration of acetone in biomethane from LF1, LF2, LF3, and WWTP1 and NG is less than the OH&SA TWAEV with 100.00% probability.

Site	LF1_Acetone (ppbv)	LF2_Acetone (ppbv)	LF3_Acetone (ppbv)	NG_Acetone (ppbv)	WWTP1_Acetone (ppbv)
Value 1	0.80	7.56	155.07	28.79	0.72
Value 2	0.23	108.60	132.60	33.01	0.70
Value 3	1.16	5.05	314.07	BDL	0.52
Value 4	2.90	45.79	280.77	1.26	-
OH&SA TWAEV (ppb)	500,000	500,000	500,000	500,000	500,000
sample size	4	4	4	3	3
mean	1.27	41.75	220.63	21.02	0.65
std dev	1.15	48.31	90.18	17.24	0.11
std error	0.58	24.15	45.09	9.96	0.06
Default Confidence Interval	95%	95%	95%	95%	95%
T Multiple	3.18	3.18	3.18	4.30	4.30
LL mean @ CI default	(0.56)	(35.12)	77.14	(21.82)	0.38
UL mean @ CI default	3.10	118.62	364.12	63.86	0.91
P(mean < OH&SA TWAEV)	100.00%	100.00%	100.00%	100.00%	100.00%

Table 28 - Comparison of Acetone Levels to OH&SA TWAEV

5.2.5.4.2. Acrolein

OH&SA Ceiling Exposure Value (CEV): 0.1 ppm

Acrolein was detected in biomethane samples from LF1. Based on the analysis, the process mean for concentration of acrolein in biomethane from LF1 is less than the OH&SA CEV with 99.92% probability.

Site	LF1_Acrolein (ppbv)	LF2_Acrolein (ppbv)	LF3_Acrolein (ppbv)	NG_Acrolein (ppbv)	WWTP1_Acrolein (ppbv)
Value 1	BDL	BDL	BDL	BDL	BDL
Value 2	BDL	BDL	BDL	BDL	BDL
Value 3	0.24	BDL	BDL	BDL	BDL
Value 4	0.76	BDL	BDL	BDL	-
OH&SA CEV (ppb)	100	100	100	100	100
sample size	2	NA	NA	NA	NA
mean	0.50	NA	NA	NA	NA
std dev	0.36	NA	NA	NA	NA
std error	0.26	NA	NA	NA	NA
Default Confidence Interval	95%	NA	NA	NA	NA
T Multiple	12.71	NA	NA	NA	NA
LL mean @ CI default	(2.74)	NA	NA	NA	NA
UL mean @ CI default	3.74	NA	NA	NA	NA
P(mean < OH&SA CEV)	99.92%	NA	NA	NA	NA

Table 29 - Comparison of Acrolein Levels to OH&SA CEV

5.2.5.4.3. Propionaldehyde

OH&SA Time Weighted Average Exposure Value (TWAEV): 20 ppm

Propionaldehyde was detected in biomethane samples from LF2, and LF3, and in NG samples. Based on the analysis, the process mean for concentration of propionaldehyde in biomethane from LF2 and LF3 and NG is less than the OH&SA TWAEV with 100.00% probability.

Site	LF1_Propionaldehyde (ppbv)	LF2_Propionaldehyde (ppbv)	LF3_Propionaldehyde (ppbv)	NG_Propionaldehyde (ppbv)	WWTP1_Propionaldehyde (ppbv)
Value 1	BDL	0.22	6.14	1.08	BDL
Value 2	BDL	1.12	6.45	1.32	BDL
Value 3	BDL		7.03	BDL	BDL
Value 4	BDL	0.23	9.02	1.29	-
OH&SA TWAEV (ppb)	20,000	20,000	20,000	20,000	20,000
sample size	NA	3	4	3	-
mean	NA	0.52	7.16	1.23	NA
std dev	NA	0.52	1.29	0.13	NA
std error	NA	0.30	0.65	0.08	NA
Default Confidence Interval	NA	95%	95%	95%	NA
T Multiple	NA	4.30	3.18	4.30	NA
LL mean @ CI default	NA	(0.77)	5.10	0.90	NA
UL mean @ CI default	NA	1.82	9.22	1.56	NA
P(mean < OH&SA TWAEV)	NA	100.00%	100.00%	100.00%	NA

Table 30 - Comparison of Propionaldehyde Levels to OH&SA TWAEV

5.2.5.4.4. Crotonaldehyde

OH&SA Ceiling Exposure Value (CEV): 0.3 ppm

Crotonaldehyde was detected in biomethane samples from LF2. Based on the analysis, the process mean for concentration of crotonaldehyde in biomethane from LF2 is less than the OH&SA CEV with 99.97% probability.

Site	LF1_Crotonaldehyde (ppbv)	LF2_Crotonaldehyde (ppbv)	LF3_Crotonaldehyde (ppbv)	NG_Crotonaldehyde (ppbv)	WWTP1_Crotonaldehyde (ppbv)
Value 1	BDL	0.117	BDL	BDL	BDL
Value 2	BDL	0.633	BDL	BDL	BDL
Value 3	BDL	BDL	BDL	BDL	BDL
Value 4	BDL	BDL	BDL	BDL	-
OH&SA CEV (ppb)	300	300	300	300	300
sample size	NA	2	NA	NA	NA
mean	NA	0.37	NA	NA	NA
std dev	NA	0.36	NA	NA	NA
std error	NA	0.26	NA	NA	NA
Default Confidence Interval	NA	95%	NA	NA	NA
T Multiple	NA	12.71	NA	NA	NA
LL mean @ CI default	NA	(2.90)	NA	NA	NA
UL mean @ CI default	NA	3.65	NA	NA	NA
P(mean < OH&SA CEV)	NA	99.97%	NA	NA	NA

Table 31 - Comparison of Crotonaldehyde Levels to OH&SA CEV

5.2.5.4.5. 2-Butanone

OH&SA Time Weighted Average Exposure Value (TWAEV): 200 ppm

2-Butanone was detected in biomethane samples from LF2, and LF3, and in NG samples. Based on the analysis, the process mean for concentration of 2-Butanone in biomethane from LF2 and LF3 and NG is less than the OH&SA TWAEV with 100.00% probability.

Site	LF1_2-Butanone (ppbv)	LF2_2-Butanone (ppbv)	LF3_2-Butanone (ppbv)	NG_2-Butanone (ppbv)	WWTP1_2-Butanone (ppbv)
Value 1	BDL	BDL	198.18	5.61	BDL
Value 2	BDL	BDL	166.94	7.05	BDL
Value 3	BDL	1.40	BDL	BDL	BDL
Value 4	BDL	18.69	BDL	BDL	-
OH&SA TWAEV (ppb)	200,000	200,000	200,000	200,000	200,000
sample size	NA	2	2	2	NA
mean	NA	10.05	182.56	6.33	NA
std dev	NA	12.22	22.09	1.02	NA
std error	NA	8.64	15.62	0.72	NA
Default Confidence Interval	NA	95%	95%	95%	NA
T Multiple	NA	12.71	12.71	12.71	NA
LL mean @ CI default	NA	(99.76)	(15.91)	(2.85)	NA
UL mean @ CI default	NA	119.85	381.02	15.51	NA
P(mean < OH&SA TWAEV)	NA	100.00%	100.00%	100.00%	NA

Table 32 - Comparison of 2-Butanone Levels to OH&SA TWAEV

5.2.5.4.6. Butanal

There is no exposure limit for butanal in OH&SA, OSHA, or NIOSH. Butanal was found in samples from LF2, LF3, and NG.

Site	LF1_Butanal (ppbv)	LF2_Butanal (ppbv)	LF3_Butanal (ppbv)	NG_Butanal (ppbv)	WWTP1_Butanal (ppbv)
Value 1	BDL	0.46	9.34	0.87	BDL
Value 2	BDL	1.63	6.46	1.01	BDL
Value 3	BDL		0.40	BDL	BDL
Value 4	BDL	0.51	0.51	0.68	-

No Exposure Limit (OH&SA, OSHA, or NIOSH)					
sample size	NA	3	4	3	NA
mean	NA	0.87	4.18	0.86	NA
std dev	NA	0.66	4.46	0.16	NA
std error	NA	0.38	2.23	0.09	NA
Default Confidence Interval	NA	95%	95%	95%	NA
T Multiple	NA	4.30	3.18	4.30	NA
LL mean @ CI default	NA	(0.78)	(2.92)	0.45	NA
UL mean @ CI default	NA	2.51	11.27	1.26	NA

Table 33 - Comparison of Butanal Levels

5.2.5.4.7. Conclusion – Analysis of Aldehydes and Ketones

Based on t-distribution analysis, the process mean for concentrations of the 6 aldehydes and ketones analyzed will be less than their respective limiting values with ≥99.92% probability, excluding Butanal. There is no established exposure limiting value for Butanal.

5.2.5.5. Conclusion - Analysis of Trace Contaminants Compliance with Exposure Limiting Values

Based on the analysis performed, it is ≥99.92% probable that the process mean of the concentration levels of the components in biomethane (whose concentration in biomethane ≥ than that in natural gas) will not exceed the acceptable limits as referenced from the OH&SA reg. 833 and OSHA.

5.3 Extrapolation to Population

The analysis of impact of input biogas quality on output biomethane quality will be addressed for the following properties/components:

- Gross Heating Value
- Wobbe Index
- Hydrogen Sulphide
- Total Sulphur
- Carbon Dioxide
- Oxygen
- Total Inerts
- Butanes Plus

A boxplot chart is presented for each property/component and observations are based on these visual representations.

It is ≥99.92% probable that the process mean of the concentration levels of the other components in biomethane (which have a concentration ≥ than in natural gas) will not exceed their respective acceptable limits as referenced from the OH&SA reg. 833 and OSHA for all the sites under consideration. Therefore, these components were not addressed to determine the affect of input gas quality on output gas quality.

5.3.1 Gross Heating Value

From Figure 5, the median gross heating value of the biogas appears to be comparable between the sites. However, the dispersion of gross heating value of biogas varies between the sites, with the dispersion being the largest at LF3.

The median gross heating values of biomethane are different for each site, suggesting that the gross heating value of biomethane is site dependant.

One may interpret from Figure 5 that the dispersion of biomethane gross heating values for each site is influenced by the dispersion of input biogas gross heating values. For example, as seen in Figure 5, the dispersion of the gross heating value for biogas is the largest for data from LF3, and correspondingly, the dispersion of gross heating value for biomethane is also the largest for data from LF3. It is also worth noting that the clean up process seems to compensate for the fluctuations in heating values of the biogas.

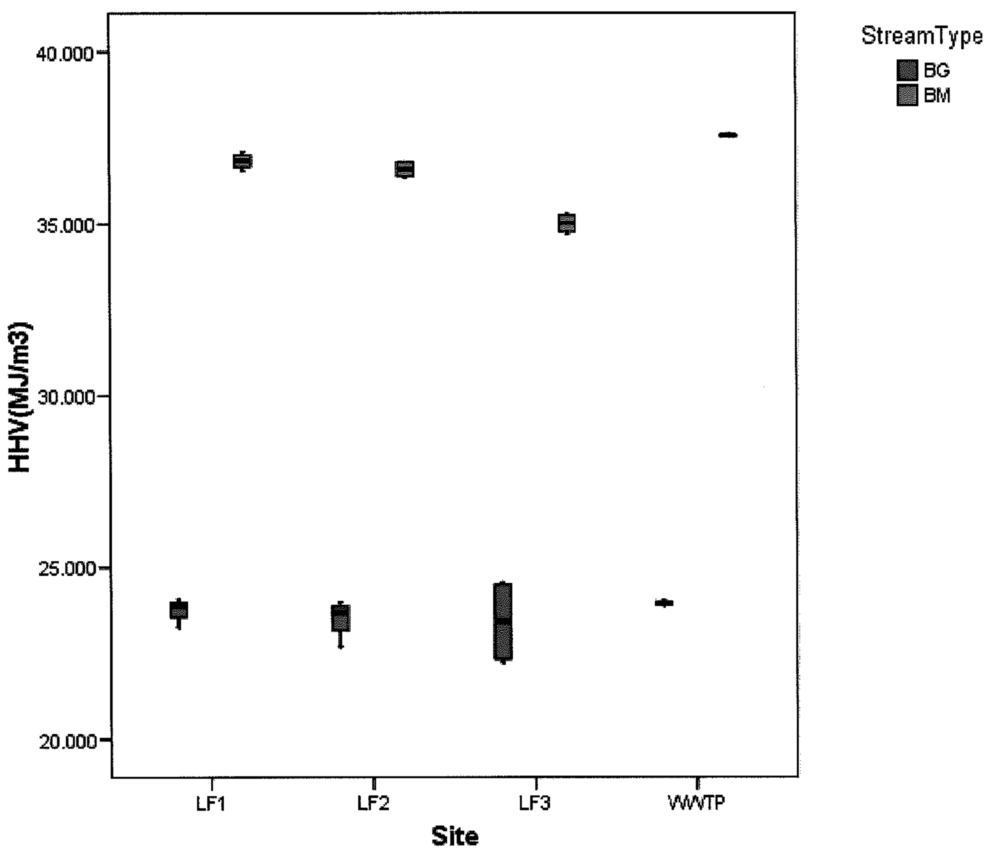

Figure 5 - Boxplot of Gross Heating Value of Biogas and Biomethane

5.3.2 Wobbe Index

From Figure 6, the median Wobbe Index of the biogas appears to be comparable between the sites. However, the dispersion of Wobbe Index of biogas varies between the sites, with the dispersion being the largest at LF3.

The median Wobbe Index values of biomethane are different for each site, suggesting that the Wobbe Index of biomethane is site dependant.

One may interpret from Figure 6 that the dispersion of biomethane Wobbe Index values for each site is dependant upon the dispersion of biogas Wobbe Index values. For example, as seen in Figure 6, the dispersion of the Wobbe Index for biogas is the largest for data from LF3, and correspondingly, the dispersion of the Wobbe Index for biomethane is also the largest for data from LF3. This result should be expected as the Wobbe index is a ratio of the higher heating value to the square root of the specific gravity of the gas.

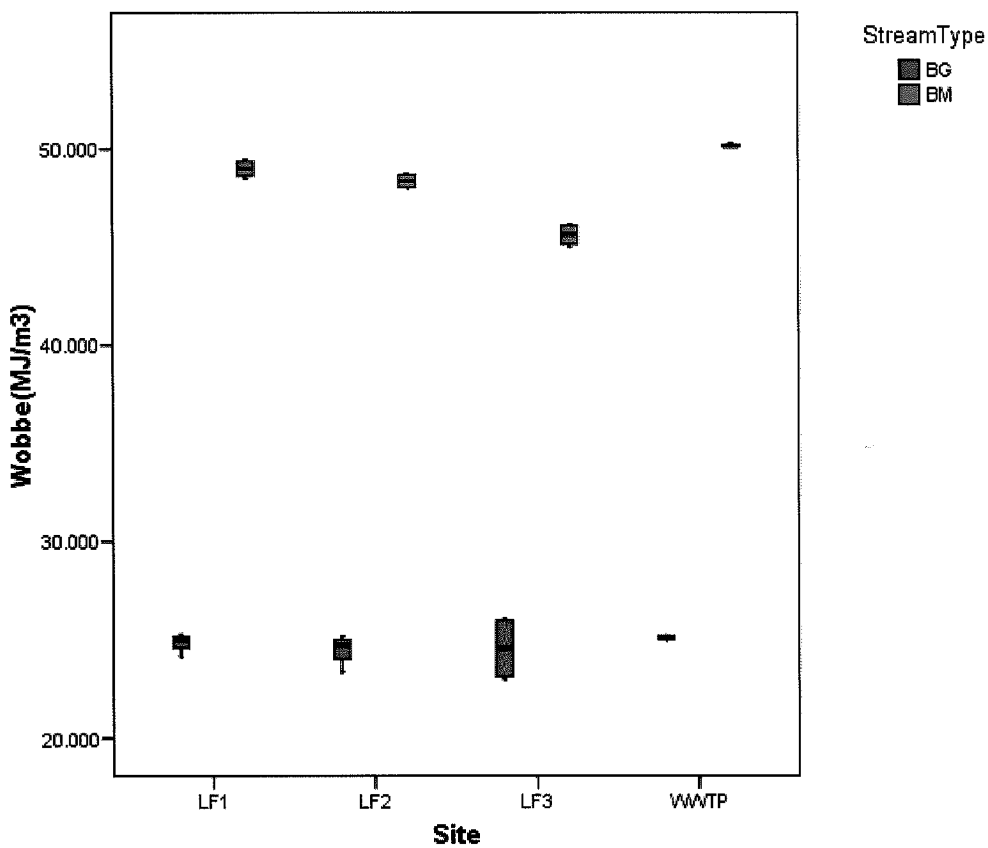

Figure 6 - Boxplot of Wobbe Index of Biogas and Biomethane

5.3.3 Hydrogen Sulphide

From Figure 7, the median hydrogen sulphide concentration in biogas appears to vary noticeably between the sites. However, the dispersion of hydrogen sulphide concentration in biogas is of similar magnitude between the sites, except for LF1. A further study would be required to determine why there is less dispersion in hydrogen sulphide concentration at LF1.

The median hydrogen sulphide concentration in biomethane is observed to be similar between the sites. The hydrogen sulphide concentration in biomethane from LF3 was below the detection limit.

The dispersion in hydrogen sulphide concentration in biomethane is much less than the dispersion in hydrogen sulphide concentration in biogas, and is also similar between the sites. As such, one may conclude that the clean up processes are able to correct for large fluctuations in input biogas hydrogen sulphide concentrations.

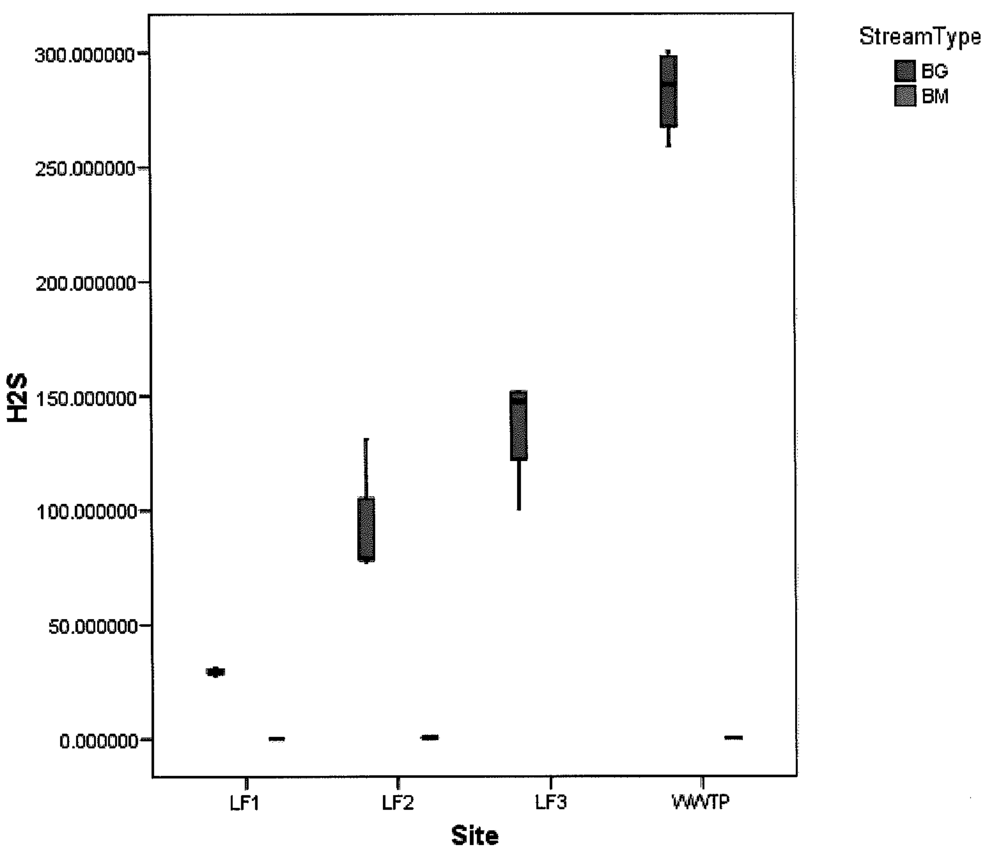

Figure 7 - Boxplot of H_2S (ppm) of Biogas and Biomethane

5.3.4 Total Sulphur

From Figure 8, the median total sulphur concentration in biogas appears to vary noticeably between the sites. However, the dispersion of total sulphur concentration in biogas is of similar magnitude between the sites, except for LF1.

The median total sulphur concentration in biomethane is observed to be similar between the sites.

The dispersion in total sulphur in biomethane is much less than the dispersion in total sulphur in biogas, and is also similar between the sites. As such, one may conclude that the clean up processes are able to correct for large fluctuations in input biogas total sulphur concentrations.

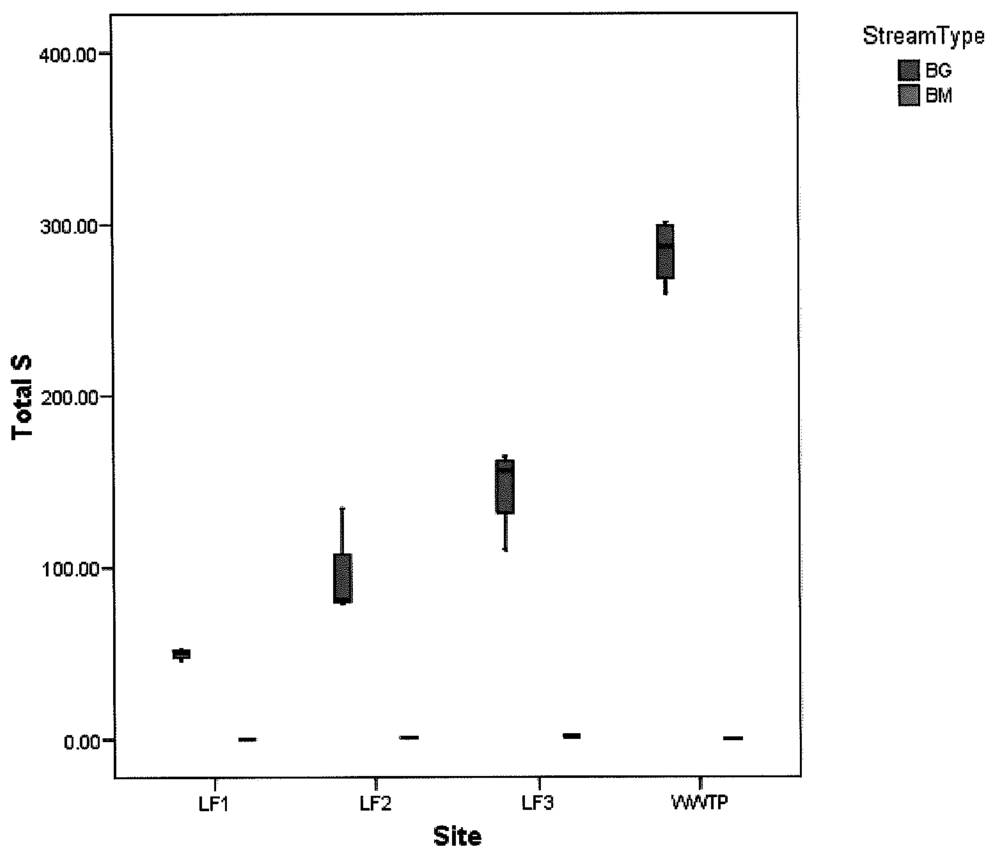

Figure 8 - Boxplot of Total Sulphur (ppm) of Biogas and Biomethane

5.3.5 Carbon Dioxide

From Figure 9, the median carbon dioxide level in biogas appears to be similar between the sites. However, the dispersion of carbon dioxide level varies between the sites.

The median carbon dioxide level in biomethane is observed to be similar between the sites.

The dispersion of carbon dioxide level in biomethane is similar between the sites, suggesting the dispersion of carbon dioxide level in biomethane is independent of the dispersion of carbon dioxide level in biogas.

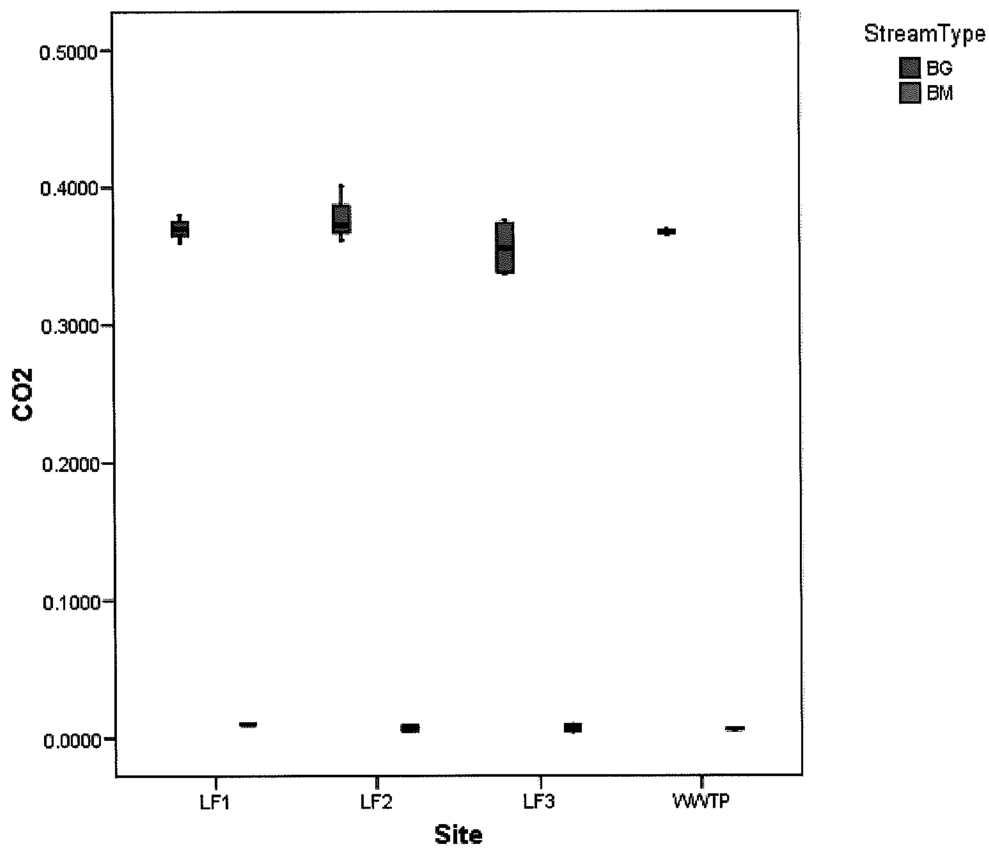

Figure 9 - Boxplot of Carbon Dioxide (mole fraction) in Biogas and Biomethane

5.3.6 Oxygen

Oxygen was below detection limit for all biogas and biomethane samples.

5.3.7 Total Inerts

From Figure 10, the median total inerts in biogas appears to be similar between the sites. However, the dispersion of total inerts varies between the sites.

The median total inerts in biomethane is observed to be different between the sites.

One may interpret from Figure 10 that the dispersion of total inerts in biomethane for each site is dependant upon the dispersion of total inerts in biogas for that site. For example, the dispersion of the total inerts in biogas is the largest for data from LF3, and the dispersion of the total inerts in biomethane is also the largest for data from LF3.

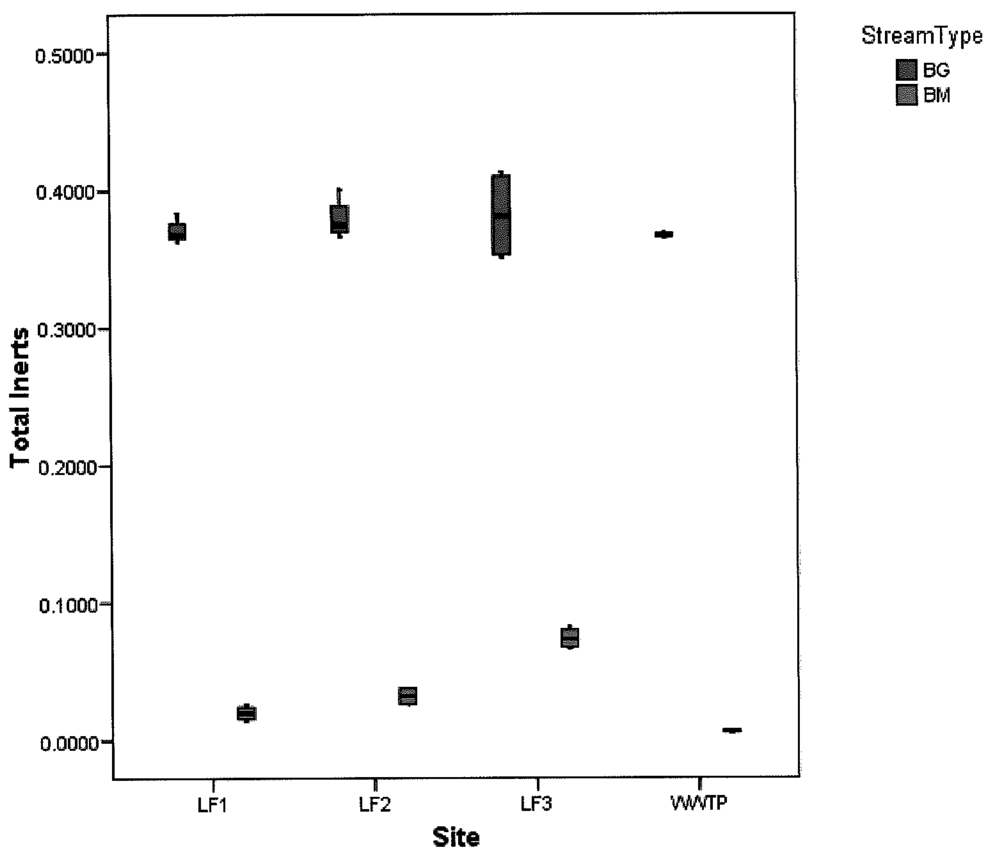

Figure 10 - Boxplot of Total Inerts (mole fraction) in Biogas and Biomethane

5.3.8 Butanes Plus

From Figure 11, the median butanes plus in biogas appear to be different between all sites.

The median butanes plus in biomethane is observed to be similar between LF1, LF2 and LF3. Butanes plus were below detection limits for biomethane from WWTP1.

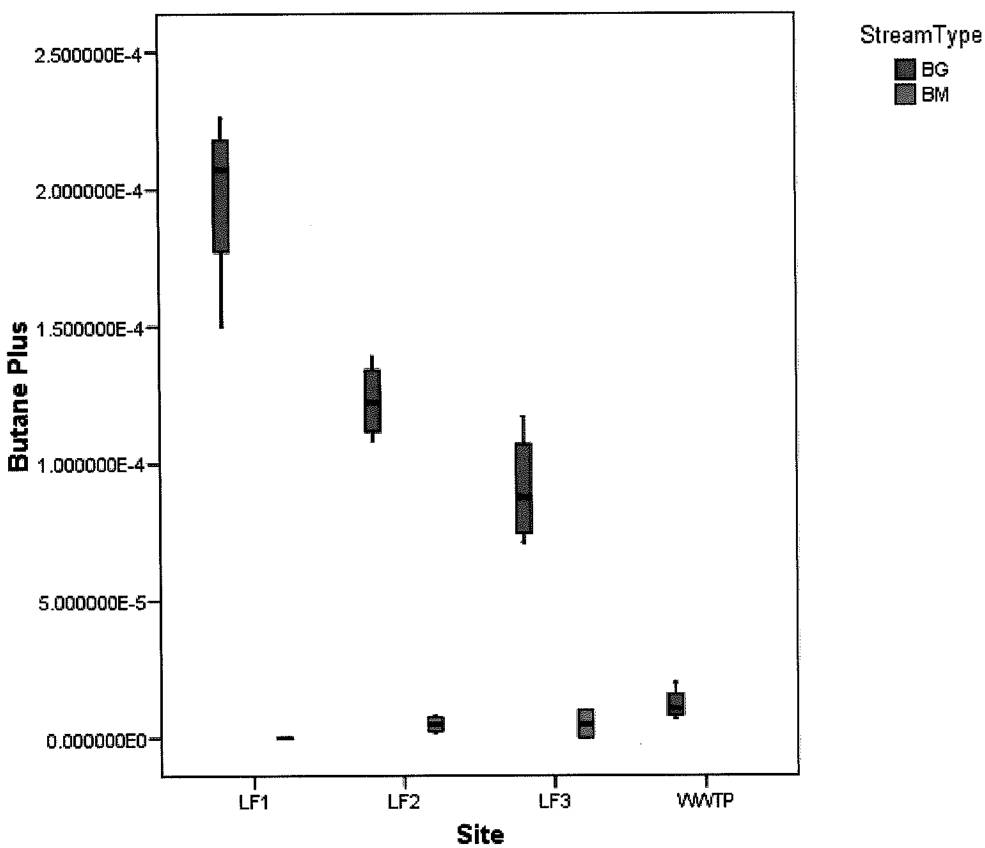

Figure 11 - Boxplot of Total Butanes Plus (mole fraction) in Biogas and Biomethane

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5.3.9 Summary of Impact of Input Biogas Quality on Output Biomethane Quality

As can be interpreted from the dispersion of biogas values to corresponding biomethane values, the clean-up processes appear to be more sensitive to the fluctuations in these input parameters:

- Gross Heating Value
- Wobbe Index
- Total Inerts

For the following parameters, the median and degree of variation in biomethane appears to be consistent between the sites, and may not be dependant on the median or degree of variation of biogas. One may interpret from this that the clean-up process can handle a wide range of input concentrations without compromising the output biomethane quality:

- Hydrogen Sulphide
- Total Sulphur
- Carbon Dioxide

It is also noted that for gross heating value and Wobbe Index, the output biomethane quality appears to be site dependant.

It is worth noting, that for all samples, biogas and biomethane, oxygen was below the detection limit. At these sites for these samples, it is observed that oxygen was controlled in the input biogas.

Water vapour was not addressed as complete analysis would have had to be completed on site. All sample analysis completed was done in the lab. Water vapour data may be collected and monitored at these sites by the operator and/or the accepting utility. Based on the design study, Appendix G, water vapour removal is a standard technology deployed at the upgrading plants and should not present an issue for biomethane injection.

6.0 Gas Supply

As discussed in Section 2.0, gas composition is directly tied to the three primary areas of concern:

- safety of the use of biomethane for end use consumers
- affects on pipeline assets
- affects on performance and asset life of end use equipment

When accepting a biomethane supply, all of these areas of concern should be addressed through the design of the biogas upgrading plant to meet gas specifications. The design of the biogas upgrading plant should have equipment/processes in place to ensure that the biomethane that will be injected is safe for use with no adverse affects. The accepting utility should also monitor to ensure the gas meets quality specifications, as will be discussed in Section 8.0.

6.1 Biologicals

The possibility of biological carry over (bacteria, spores) from a landfill site or AD via biomethane to end use consumers is a concern due to their presence in the landfill or AD. Pathogenic bacteria and corrosion causing bacteria are the two categories of biologicals that have been cited as a concern.

In 2006, a research paper was published by the Swiss, concluding that the risk for transmission of diseases through biomethane was very low. This conclusion was based on lab analysis of biogas and biomethane from two separate biogas upgrading plants, shown in Figure 12. The risk of inhaling pathogens was determined to be overshadowed by the risk of gas intoxification and explosions. It was also concluded that a general 1 μm filter will ensure filtration of the majority of fungi and non-spore forming bacteria from the biomethane, ensuring that they do not enter the gas distribution system. Finally, natural gas was analysed for biological content for comparison with that in biomethane, and it was found that the density of microorganisms was similar between natural gas and biomethane. It was also found that the natural gas contained spore forming bacteria.[5]

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[5] Vinneras, B., Schönning, C., Nordin, A., "Identification of the microbiological community in biogas systems and evaluation of micробrial risks from gas usage," Science of the Total Environment (367), 2006

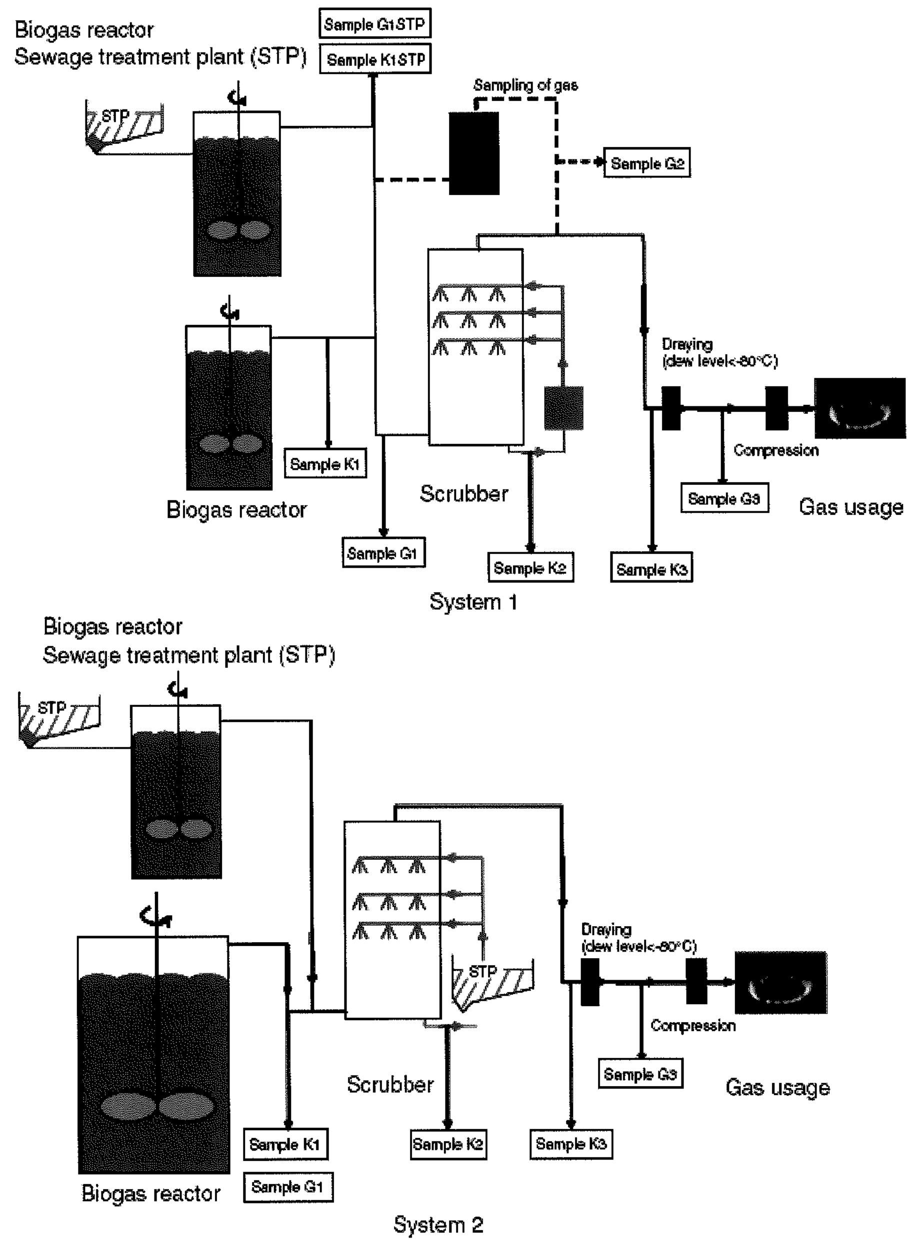

Figure 12 - Biogas Treatment Plants investigated in Swiss Study[5]

In April 2008, a publication by Lettinga Associates Foundation (LeAF) summarized the available data on risks of transmission of pathogens through biogas. This report contained no analysis of biogas or laboratory experiments, but summarized data available at that time. The inactivation of pathogens during biogas upgrading and transport were not taken into account. The assumption was made that any pathogen that survives the anaerobic digestion process will end up in the gas that is transported to the end use customer. Conclusions drawn from their research included that the risk of exposure of end use customers to pathogens from biogas was limited to gas released prior to ignition, as after ignition the pathogens are inactivated in the flame, and due to the volume of gas released the risk of pathogen exposure was judged to be very low for end use consumers. The pathogen content in biogas can be linked to the type of AD (less pathogens in thermophilic than mesophilic than phsychrophilic), and the retention time in the AD (longer retention time results in inactivation of more pathogens). Also, drying and/or filtering of the biogas will remove or inactivate most pathogens, but not spores. The other consideration that can be taken into account is the quality of the biomass that is undergoing anaerobic digestion.[6]

In 2006, AFFSET (the French agency for health security) commenced an evaluated of the health risks associated with biogas utilization for domestic consumers. In October 2008, the final recommendations of this evaluation were published. AFFSET advised that the injection of biogas derived from household waste, agricultural waste and organic waste from the food industry posed no health related with for domestic gas utilization. They deemed that further research was required for biogas from wastewater treatment plants and biogas from industrial waste. A translation of the executive summary of the AFFSET report can be found in Appendix E.

As part of the gas sampling and laboratory analysis undertaken as part of this project, analysis was performed on samples collected from biomethane and natural gas streams. These tests were to: quantify the number of live bacteria, quantify and identify the total number of bacteria (live plus dead), quantify corrosion causing bacteria, and quantify and identify the total number of spores. The three groups of corrosion causing bacteria that were quantified were: sulphate-reducing bacteria (SRB), acid-producing bacteria (APB), and iron-oxidizing bacteria (IOB). Table 34, Table 35, and Table 36 summarize the results of the laboratory analysis. Appendix D includes further description of bacteria and spores, description of the sampling techniques, and identification of the bacteria and spores.

[6] Bisschops, I., van Eekert, M., "Inventory of Risks of Pathogen Transmission from Biogas," LeAF, April 2008

Sample ID	Anaerobic	Aerobic	Total
	Bacteria (#/100 scf)		
1NG01BC	<108*	1.08E+02	1.08E+02
1NG02BC	<170*	<170*	<340*
2NG01BC	4.39E+02	5.85E+03	6.29E+03
2NG02BC	<149*	5.46E+05	5.46E+05
3NG01BC	3.70E+04	5.84E+04	9.55E+04
3NG02BC	1.99E+05	4.19E+04	2.40E+05
LF1BM01BC	<170*	3.96E+02	3.96E+02
LF1BM02BC	<170*	<170*	<340*
LF1BM03BC	<92*	<92*	<184*
LF1BM04BC	<83*	<83*	<166*
LF2BM01BC	<76*	<76*	<152*
LF2BM02BC	<81*	<81*	<162*
LF2BM03BC	<184*	<184*	<368*
LF2BM04BC	<170*	<170*	<340*
LF3BM01BC	<102*	1.53E+03	1.53E+03
LF3BM02BC	<155*	<155*	<310*
LF3BM03BC	<117*	<117*	<234*
LF3BM04BC	<73*	<73*	<146*
LF4BG01BC	<90*	9.00E+01	9.00E+01
WWTP1BM01BC	<74*	1.10E+03	1.10E+03
WWTP1BM02BC	3.98E+02	1.45E+02	5.43E+02
WWTP1BM03BC	<66*	5.52E+02	5.52E+02
WWTP1BM04BC	1.69E+02	1.08E+03	1.25E+03

Table 34 -Total Live Bacteria via MPN analysis

Sample ID	Total Bacteria	Total acid-producing bacteria (APB)	Total iron-oxidizing bacteria (IOB)	Total sulfate-reducing bacteria (SRB)
	Bacteria (#/100scf)			
1NG01BC	1.94E+06	6.55E+04	4.29E+03	BDL
1NG02BC	6.68E+05	1.45E+05	9.99E+03	BDL
2NG01BC	3.20E+06	BDL	2.16E+04	BDL
2NG02BC	2.06E+06	4.19E+04	9.49E+03	BDL
3NG01BC	4.86E+06	2.71E+05	BDL	BDL
3NG02BC	7.39E+06	4.99E+05	1.19E+04	BDL
LF1BM01BC	6.70E+06	2.73E+04	8.30E+02	BDL
LF1BM02BC	3.19E+06	2.75E+04	2.10E+04	BDL
LF1BM03BC	2.16E+06	8.50E+03	1.28E+04	BDL
LF1BM04BC	1.68E+06	2.92E+03	1.02E+04	BDL
LF2BM01BC	1.78E+07	2.97E+04	BDL	BDL
LF2BM02BC	3.75E+06	7.86E+03	BDL	BDL
LF2BM03BC	3.62E+04	5.13E+03	BDL	BDL
LF2BM04BC	2.98E+04	1.78E+03	BDL	BDL
LF3BM01BC	1.68E+06	4.66E+04	BDL	BDL
LF3BM02BC	2.22E+07	1.03E+04	1.36E+04	BDL
LF3BM03BC	8.79E+05	4.12E+04	BDL	BDL
LF3BM04BC	2.46E+04	BDL	BDL	BDL
LF4BG01BC	1.33E+06	1.90E+04	3.25E+03	BDL
WWTP1BM01BC	2.14E+06	2.25E+04	2.97E+03	BDL
WWTP1BM02BC	1.64E+06	6.54E+04	BDL	BDL
WWTP1BM03BC	9.85E+05	1.35E+04	BDL	BDL
WWTP1BM04BC	1.08E+06	1.91E+04	BDL	BDL

Table 35 - Total Bacteria and Corrosion Causing Bacteria via qPCR

Types of bacteria identified included typical environmental isolates (Paenibacillus sp., and Bacillus sp.), as well as isolates associated with the human body (Streptococcus salivarius, and Stphlococcus epidermis). These identifications include live and dead bacteria, as the qPCR technique does not differentiate between the two.

Sample ID	Anaerobic	Aerobic	Total
	Spores (#/100 scf)		
1NG01BC	*	1.79E+03	1.79E+03
1NG02BC	*	*	*
2NG01BC	*	*	*
2NG02BC	*	*	*
3NG01BC	*	*	*
3NG02BC	*	*	*
LF1BM01BC	*	*	*
LF1BM02BC	*	*	*
LF1BM03BC	*	*	*
LF1BM04BC	*	*	*
LF2BM01BC	*	*	*
LF2BM02BC	*	*	*
LF2BM03BC	*	*	*
LF2BM04BC	*	*	*
LF3BM01BC	*	1.70E+02	1.70E+02
LF3BM02BC	*	*	*
LF3BM03BC	*	1.94E+02	1.94E+02
LF3BM04BC	*	4.87E+02	4.87E+02
LF4BG01BC	*	*	*
WWTP1BM01BC	2.46E+03	*	2.46E+03
WWTP1BM02BC	3.62E+03	*	3.62E+03
WWTP1BM03BC	6.62E+03	*	6.62E+03
WWTP1BM04BC	*	1.21E+04	1.21E+04

Table 36 - Total Spores via NASA protocol

Spores identified included: a spore forming bacteria closely related to Paenibacillus glucanolyticus (1NG01BC), Bacillus sp. (LF3 samples), and Paenibacillus sp. (WWTP samples).

Different techniques can be considered and implemented to minimize the number of biologicals in biomethane. These techniques include pasteurization of the biomass prior to anaerobic digestion[5], drying of the biomethane prior to injection[6], and filtering of the biomethane prior to injection[5].

6.2 Interchangeability Analysis

Interchangeability is defined as "the ability to substitute one gaseous fuel for another in a combustion application without materially changing operational safety, efficiency, performance or materially increasing air pollutant emissions."[7]

Interchangeability analysis has been completed on historical natural gas supplies, potential future gas supplies, and existing biomethane injection sites. The historical supply utilized in these calculations is based on daily average compositions from Victoria Square gate station from January 1, 2000 to December 31, 2009. Three representative gas compositions were defined to represent a low, median, and high gas. The low and high gas bracket 85% of the historical calculated Wobbe Index number data points as per Figure 13.

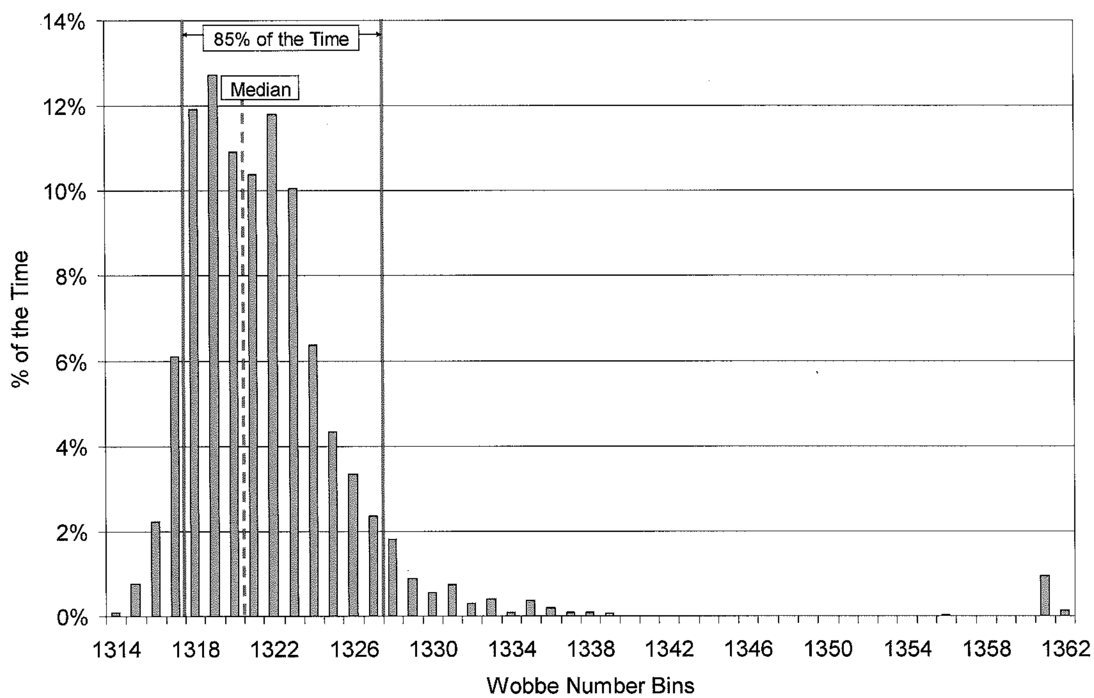

Figure 13 - Histogram Victoria Square Wobbe Index Numbers

Future gas supplies chosen for interchangeability analysis included representative low and high compositions for shale gas and low and high compositions for LNG. These compositions were derived to ensure that the gas quality specifications of the TransCanada transportation tariff are satisfied.

[7] NGC+ Interchangeability Work Group, "White Paper on Natural Gas Interchangeability and Non-Combustion End Use," February 2005

Interchangeability calculations (Weaver indices and AGA indices) were performed using both forward and reverse calculations for the following scenarios:

- Interchangeability of Low Wobbe Index Number Victoria Square Historical Supply and High Wobbe Index Number Unblended Biomethane (WWTP)
- Interchangeability of High Wobbe Index Number Victoria Square Historical Supply and Low Wobbe Index Number Unblended Biomethane (LF)
- Interchangeability of Median Victoria Square Historical Supply and Unblended Biomethane (All)
- Interchangeability of Low Wobbe Index Number Shale Gas and High Wobbe Index Number Unblended Biomethane (WWTP)
- Interchangeability of High Wobbe Index Number Shale Gas and Low Wobbe Index Number Unblended Biomethane (LF)
- Interchangeability of LNG with Low Wobbe Index Number Unblended Biomethane (LF)

The scenarios above were chosen as they represent the largest differences in Wobbe Index numbers. An example of the calculations is shown in Table 37; all remaining calculations can be found in Appendix F.

		LF1-Low	LF1-High	LF2-Low	LF2-High	LF3-Low	LF3-High	WWTP	Limits
	HHV (Btu/scf)	981	987	976	988	931	947	1008	
	Wobbe	1302	1309	1289	1307	1208	1238	1346	**1269-1375**
FORWARD CALCULATIONS (Adjustment Gas: Victoria-Median; Substitute Gas: Unblended Biomethane)									
WEAVER	Flashback	0.034	0.021	0.020	0.007	0.079	0.056	-0.022	**≤ 0.26**
	Yellow Tipping	-0.034	-0.029	-0.043	-0.029	-0.105	-0.082	-0.001	**≤ 0.30**
	Incomplete Combustion	-0.021	-0.015	-0.028	-0.014	-0.090	-0.067	0.015	**≤ 0.05**
	Lifting	0.997	0.996	0.961	0.982	0.876	0.908	1.022	**≥ 0.64**
	Heat Rate Ratio	0.985	0.990	0.976	0.989	0.914	0.937	1.018	**0.96 – 1.04**
AGA	Lifting	1.010	1.008	1.029	1.013	1.103	1.074	0.980	**≤ 1.06**
	Flashback	1.003	0.999	0.997	0.996	1.007	1.003	0.992	**≤ 1.20**
	Yellow Tipping	1.040	1.031	1.057	1.033	1.168	1.125	0.989	**≥ 0.80**
REVERSE CALCULATIONS (Adjustment Gas: Unblended Biomethane; Substitute Gas: Victoria-Median)									
WEAVER	Flashback	-0.034	-0.021	-0.020	-0.007	-0.089	-0.061	0.021	**≤ 0.26**
	Yellow Tipping	0.034	0.029	0.044	0.029	0.113	0.086	0.001	**≤ 0.30**
	Incomplete Combustion	0.021	0.015	0.029	0.014	0.098	0.071	-0.014	**≤ 0.05**
	Lifting	1.003	1.004	1.040	1.018	1.141	1.102	0.978	**≥ 0.64**
	Heat Rate Ratio	1.015	1.010	1.025	1.011	1.094	1.067	0.982	**0.96 – 1.04**
AGA	Lifting	0.990	0.992	0.971	0.987	0.901	0.928	1.020	**≤ 1.06**
	Flashback	0.986	0.992	0.989	0.997	0.957	0.969	1.010	**≤ 1.20**
	Yellow Tipping	0.962	0.970	0.946	0.968	0.856	0.889	1.011	**≥ 0.80**

Table 37 - Example of Summary Interchangeability Analysis with Victoria Square Historical Median Supply

In Table 37, calculations in columns LF-1 to WWTP are compared to the Limits set out in the right side column. If the calculations are within the limits, then the two gases are interchangeable by the definition of the indices. If the calculated value is not within the limits, then it is shaded red. Gases that show red values can be blended with natural gas or with propane in order to ensure that they meet interchangeability requirements.

6.3 Biomethane Decision Making Process

Developing a biomethane specification for a site may be an iterative process. One possible decision making process is presented in Figure 14. A complete explanation for each step can be found in Appendix F. Other considerations could include:

- Assessing direct injection and blending concurrently (Steps 2 to 5) to obtain two separate designs
- Conducting pipeline dynamics assessment concurrently with Step 2

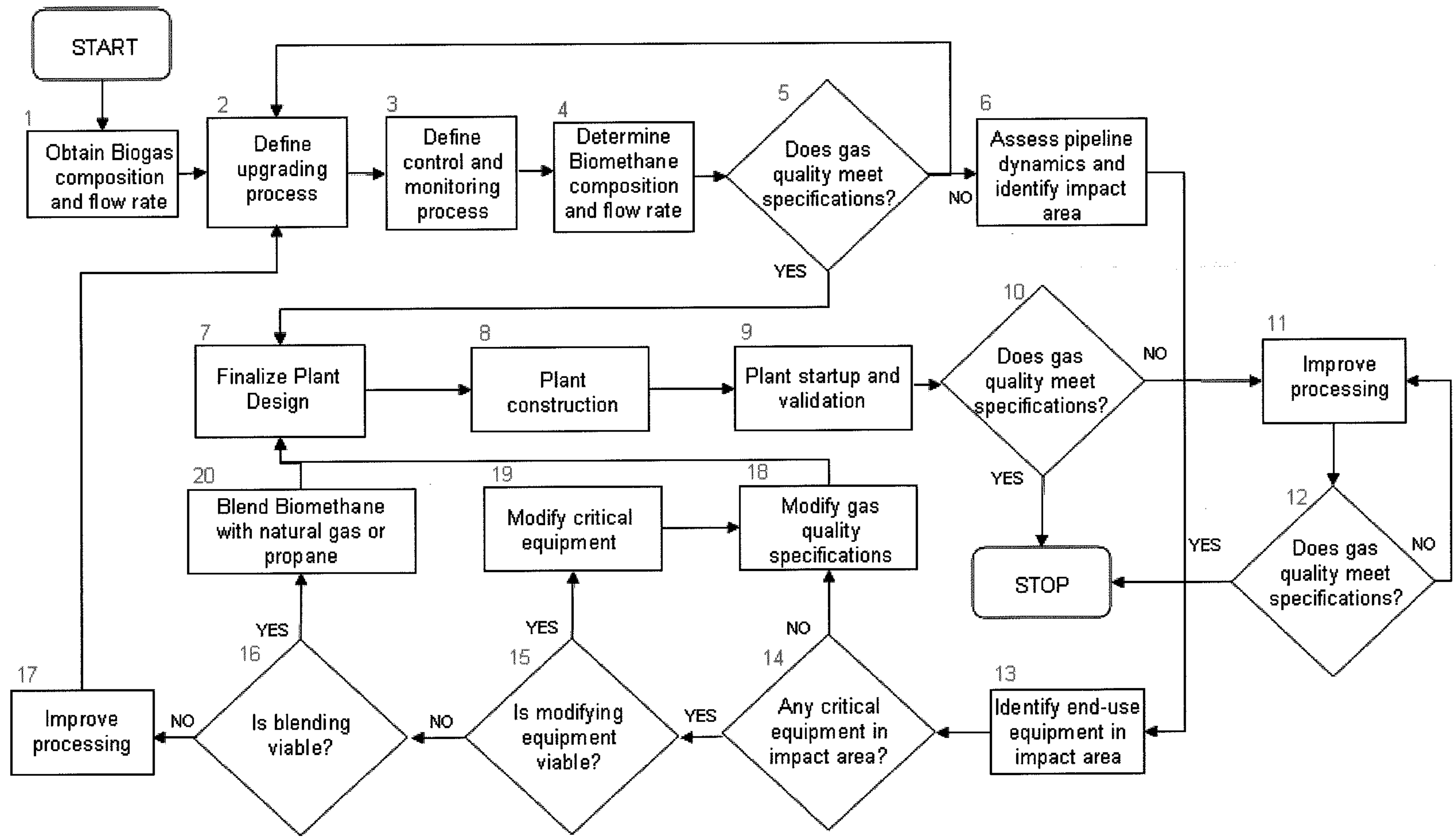

Figure 14 - Biomethane Project Decision Making Process

7.0 Project Specific Design

Theoretical designs were completed for four case specific biogas upgrading plants. Information for each of these designs is presented in Table 38.

Case Study No.	1	2	3	4
Biogas Source	AD of SSO	Landfill	AD of Clean Organics	WWTP
Biogas Flow Rate (Nm^3/h)	1,375	11,792	236	2,360
Methane	59.9%	59.3%	62.1%	57.8%
Hydrogen Sulphide (ppmv)	1,590	46	1,000	190
Injection Pressure (psi)	175	1,000	100	175

Table 38 - Case Studies for Project Specific Design

Each of these designs contains up to 11 modules: Pre-treatment Unit (Module 1), H_2S Removal Unit (Module 2), Feed Gas Compression Unit (Module 3), Post Feed Gas Compression Unit (Module 4), 2nd Stage Compression Unit (Module 5), First Stage PSA Unit (Module 6), Second Stage PSA Unit (Module 7), Exhaust Blower Unit (Module 8), Product Gas Compression Unit (Module 9), Power (Module 10), and Instrument Air (Module 11). The purpose of each Module is outlined in Appendix G.

The process flow for a plant which contains all eleven modules is seen in Figure 15. Biogas composition at each site dictated the need for certain modules. Not all eleven modules are contained in each case specific design

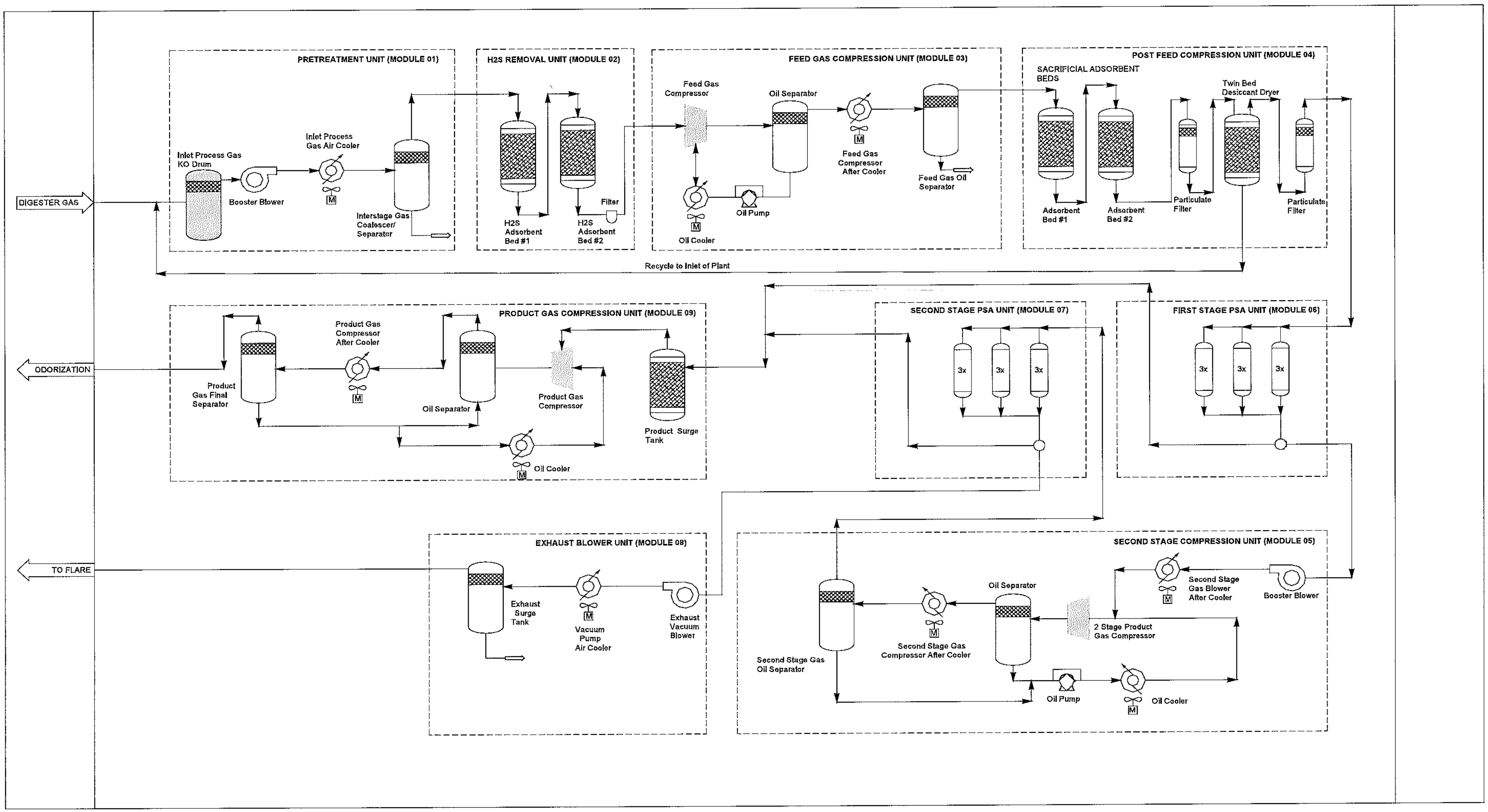

Figure 15 - General Process Flow Diagram

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Capital expenditures and annual operating expenditures were estimated for each of these plants within ±25% accuracy. Capital expenditures were estimated using three different set of assumptions:

Assumption A:	**Assumption B:**	**Assumption C:**
Provide supervisory assistance: 110 hours of Facility support (supervision) 160 hours of Construction support (supervision) 585 hours of Installation support (supervision) 920 hours of Plant Commissioning, Start-up and Testing	Power in place Short pipe lengths Favourable soil analysis Simple communications 920 hours of Plant Commissioning, Start-up and Testing	Power not available Considerable piping Unfavourable soil analysis Complex communications 920 hours of Plant Commissioning, Start-up and Testing

Table 39 - Assumptions for Capital Expenditures

The complete design report can be found in Appendix G.

For the purposes of financial analysis, capital expenditures derived utilizing Assumption B were employed. Several other assumptions needed to be made in order to develop a financial model. Assumptions were made with regards to biogas purchase price, biomethane sales price, capital expenditures, operating expenditures, compressor replacement, and taxes. These assumptions, along with complete financials, can be found in Appendix H.

Sensitivity Analysis was performed for each case study. IRR, NPV, biomethane sales price, and biogas purchase price were all considered in the sensitivity analysis.

7.1 Case Study 1 – Biogas from Anaerobic Digestion of Source Separated Organics

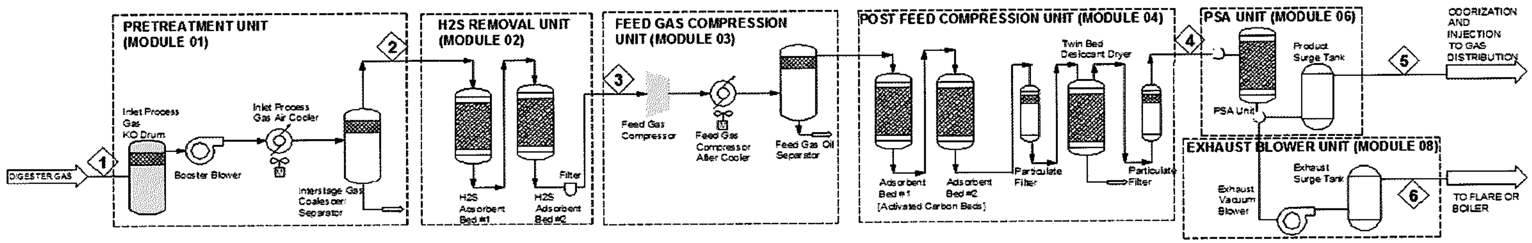
Source separated organics (SSO), is organic material which is collected from residential and commercial customers. Home-owners or commercial companies separate their organic waste and place it in a separate bin from their inorganic waste. Once collected, SSO can be treated using anaerobic digestion (AD). One product of AD is biogas. Case Study 1 proposes one possible upgrading design for the resulting biogas. This design also includes the requirements for injection of the output biomethane into the natural gas distribution system.

In order to determine an appropriate biogas composition, biogas samples were collected at an existing anaerobic digester for SSO. The size of the plant (tonnes/year) was not the same as the size of the plant utilized for the case study. In order to utilize the available biogas composition for the design of case study 1, the following assumptions were made:

- Biogas composition will be consistent between different sizes of plants provided the organic content has not changed
- The organic content has not changed
- The percentage of inorganic content introduced into the AD has not changed (estimated at between 10 and 20%)
- Biogas flow rate will be proportional to the size of the anaerobic digester

7.1.1 Process Flow

Figure 16 presents the process flow diagram for Case Study 1. The process flow diagram includes the modules required to upgrade the biogas to meet biomethane composition requirements. The "Stream Flows" section of Figure 16 presents the gas composition as the gas is upgraded through each of the Modules. This design includes eight modules. The power module and instrument air module are not presented in Figure 16 as they do not affect the gas composition.



	STREAM FLOWS NCMH - MOL%			1		2		3		4		5		6	
				TOTAL FEED		FEED TO H2S REMOVAL UNIT		FEED TO COMPRESSOR		FEED TO PSA		PRODUCT		EXHAUST	
PROCESS STREAM	STREAM COMPOSITION		MW												
	METHANE (WET BASIS)	CH4	16.0	852.5	59.9%	852.5	60.7%	852.5	60.7%	852.5	61.7%	700.1	97.9%	152.4	23.1%
	CARBON DIOXIDE	CO2	44.0	522.2	37.2%	522.2	37.7%	522.2	37.7%	522.2	38.3%	14.8	2.1%	507.4	76.9%
	WATER	H2O	18.0	$3.4\ kg/m^3$		$2.8\ kg/m^3$		2.8 kg/m3		$< 10\ mg/m^3$		$< 0.2\ mg/m^3$		$> 9.8\ mg/m^3$	
	WATER (VOLUME %)	H2O	18.0	2.9%		1.6%		1.6%		$< 2 \times 10^{-6}$ %		$< 2 \times 10^{-6}$ %		$> 2 \times 10^{-6}$ %	
	IMPURITIES														
	HYDROGEN SULPHIDE	H2S		1590 ppmv		1590 ppmv		< 50 ppmv		< 50 ppmv		< 5 ppmv		< 50 ppmv	
	CARBON MONOXIDE	CO		< 0.5 ppmv		< 0.5 ppmv		< 0.5 ppmv		< 0.5 ppmv		< 0.5 ppmv		< 0.5 ppmv	
	AMMONIA	NH3		17 ppmv		17 ppmv		< 17 ppmv		< 17 ppmv		< 10 ppmv		< 40 ppmv	
	SULPHUR DIOXIDE	SO2		< 0.01 ppmv		< 0.01 ppmv		< 0.01 ppmv		< 0.01 ppmv		< 0.01 ppmv		< 0.01 ppmv	
	MERCAPTAN			5 ppmv		5 ppmv		< 0.05 ppmv		< 0.05 ppmv		< 0.05 ppmv		< 0.05 ppmv	
	SILOXANES			8 mg/m3		8 mg/m3		< 0.5 ppmv Si		< 0.5 ppmv Si		< 0.5 ppmv Si		< 0.5 ppmv Si	
	HALOGENATED COMPOUNDS			1 ppmv		1 ppmv		< 0.1 ppmv		< 0.1 ppmv		< 0.1 ppmv		< 0.1 ppmv	
	VOC's			169 ppmv		169 ppmv		< 0.05 ppbv		< 0.05 ppbv		< 0.05 ppbv		< 0.05 ppbv	
	HEAVY METALS			$< 900 \times 10^{-6}\ g/m^3$		$< 900 \times 10^{-6}\ g/m^3$		$< 30 \times 10^{-6}\ g/m^3$		$< 30 \times 10^{-6}\ g/m^3$		$< 30 \times 10^{-6}\ g/m^3$		$< 30 \times 10^{-6}\ g/m^3$	
	TOTAL		NM³/H	1375		1375		1375		1375		715		660	
PROCESS CONDITION	TEMPERATURE		°C	32		25		25		25		25		Downstream Equipment Specification	
	TEMPERATURE		°F	90		77		77		77		77			
	PRESSURE		kPA(A)	108		205		170		1585		1485			
	PRESSURE		BARA	1.1		2.1		1.7		15.9		14.9			
	PRESSURE		PSIA	15.7		29.7		24.7		229.9		215.4			
	PRESSURE		PSIG	1.0		15.0		10.0		215.2		200.7			

Figure 16 - Process Flow Diagram - Biogas from Anaerobic Digestion of Source Separated Organics

7.1.2 Financials

Utilizing assumption B for capital expenditures, the following data was input into the financial model:

Capital Expenditure (Year 0): $4,147,500
Annual Operating Expenditure (Year 1): $814,681
Compressor Replacement (Year 10): $542,453
Biomethane Sales Price (Year 0): $8/GJ
Biogas Purchase Price: $0/GJ

The resulting financial measures are:

Net Present Value (NPV): $2.5 M at assumptions stated above
Internal Rate of Return (IRR): 13% at assumptions stated above

Cash flow completed for Years 0 to 20 can be found in Appendix H.

7.1.3 Sensitivity Analysis

In order to address the uncertainty in the estimates for Initial Capital Investment, and Annual Operating Expenditure, sensitivity analysis was completed. The original estimates were compared to the original estimate minus 25%, and the original estimate plus 25%. The resulting affects on NPV and IRR can be seen in Table 40 and Table 41.

		Initial Capital Investment		
		$ 3,110,625	$ 4,147,500	$ 5,184,375
Annual	$ 599,030	$ 4,895,576	$ 4,165,633	$ 3,431,176
Operating	$ 798,707	$ 3,193,671	$ 2,502,463	$ 1,737,123
Expenditure	$ 998,384	$ 1,451,171	$ 783,364	$ 101,991

Table 40 - Case Study 1 NPV Sensitivity Capital Investment vs. Operating Expenditure

		Initial Capital Investment		
		$ 3,110,625	$ 4,147,500	$ 5,184,375
Annual	$ 599,030	22.01%	16.90%	13.66%
Operating	$ 798,707	17.15%	13.11%	10.35%
Expenditure	$ 998,384	11.73%	8.74%	6.75%

Table 41 - Case Study 1 IRR Sensitivity Capital Investment vs. Operating Expenditure

Biomethane sales price and biogas purchase price are also two factors that have a large influence on the financial model. In the calculations, the biomethane sales price is estimated at $8/GJ based on discussions with industry. The biogas sales price was

assumed to be $0/GJ. The impacts on IRR and NPV by changing the biomethane sales price or biogas purchase price can be seen in Table 42 and Table 43.

	2009 Biomethane Sales Price ($CDN/GJ)				
	$ 6	$ 7	$ 8	$ 9	$ 10
NPV	$ (562,751)	$ 932,179	$ 2,502,461	$ 3,988,443	$ 5,567,503
IRR	5%	9%	13%	17%	20%

Table 42 - Biomethane Sales Price Sensitivity Analysis Case Study 1

	2009 Biogas Price ($CDN/GJ)			
	$ -	$ 1	$ 2	$ 3
NPV	$ 2,502,461	$ 772,228	$ (903,891)	$ (2,609,591)
IRR	13%	9%	4%	-4%

Table 43 - Biogas Purchase Price Sensitivity Analysis Case Study 1

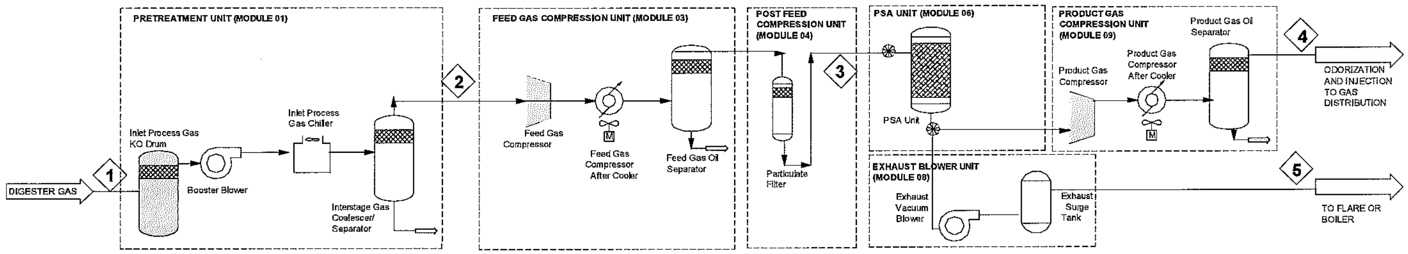
7.2 Case Study 2 – Landfill Gas

Once a cell at a landfill is filled and capped, an anaerobic environment is created for the breakdown of organic materials. Landfill gas is a product of this process, and if not captured, is released into the atmosphere as a greenhouse gas. Landfill gas can be captured through the installation of a landfill gas collection system. The collected gas can then be flared or utilized. Case Study 2 proposes one possible upgrading design for the resulting landfill gas from a theoretical landfill site. This design also includes the requirements for injection of the output biomethane into the natural gas transmission system.

In order to determine an appropriate biogas composition, landfill gas samples were collected at a landfill site. The data available for this landfill site was utilized to complete the theoretical design.

7.2.1 Process Flow

Figure 18 presents the process flow diagram for Case Study 2. The process flow diagram includes the modules required to upgrade the biogas to meet biomethane composition requirements. The "Stream Flows" section of Figure 18 presents the gas composition as the gas is upgraded through each of the Modules. This design includes eight modules. The power module and instrument air module are not presented in Figure 18as they do not affect the gas composition.



STREAM FLOWS NCMH - MOL%				1 TOTAL FEED		2 FEED TO COMPRESSOR		3 FEED TO PSA		4 PRODUCT		5 EXHAUST	
PROCESS STREAM	STREAM COMPOSITION		MW										
	METHANE	CH4	16.0	6997.4	59.3%	6997.4	59.3%	6997.4	59.3%	5947.8	97.5%	1049.6	18.4%
	CARBON DIOXIDE	CO2	44.0	4764.0	40.4%	4764.0	40.4%	4764.0	40.4%	122.0	2.0%	4642.0	81.5%
	NITROGEN	N2	28.0	30.7	0.3%	30.7	0.3%	30.7	0.3%	28.8	0.5%	1.8	0.0%
	WATER	H2O	18.0	3.4 kg/m3		0.34 kg/m3		0.30 kg/m3		< 0.2 mg/m³		> 2.8 kg/m3	
	WATER (VOLUME %)	H2O	18.0	4.4%		0.3%		0.3%		< 2 x 10⁻⁸ %		3.7%	
	IMPURITIES												
	HYDROGEN SULPHIDE	H2S		< 46 ppmv		< 46 ppmv		< 46 ppmv		0.05 ppmv **		< 46 ppmv	
	CARBONYL SULFIDE	COS		0.22 ppmv		< 0.22 ppmv		< 0.22 ppmv		< 0.004 ppmv		< 0.216 ppmv	
	OTHER SULPHUR COMPOUNDS			2.16 ppmv		0.17 ppmv		0.17 ppmv		< 0.06 ppmv		> 0.16 ppmv	
	MERCAPTAN			0.9 ppmv		0.07 ppmv		0.07 ppmv		< 0.02 ppmv		> 0.05 ppmv	
	SILOXANES			3.6 ppmv		< 0.29 ppmv		< 0.29 ppmv		< 0.006 ppmv		> 0.284 ppmv	
	HALOGENATED COMPOUNDS			9.6 ppmv		0.77 ppmv		0.77 ppmv		< 0.015 ppmv		> 0.75 ppmv	
	VOC's			0.5 ppmv		0.04 ppmv		0.04 ppmv		< 0.0008 ppmv		> 0.04 ppmv	
	MERCURY			0.6×10^{-6} g/m³		$< 0.2 \times 10^{-6}$ g/m³		$< 0.2 \times 10^{-6}$ g/m³		$< 0.2 \times 10^{-6}$ g/m³		$< 0.2 \times 10^{-6}$ g/m³	
	ARSENIC/ANTIMONY/ZINC			283×10^{-6} g/m³		$< 30 \times 10^{-6}$ g/m³		$< 30 \times 10^{-6}$ g/m³		$< 30 \times 10^{-6}$ g/m³		$< 30 \times 10^{-6}$ g/m³	
	MICRO-ORGANISMS			1.33×10^{-6} cells/ft³		No Growth Detected		No Growth Detected		No Growth Detected		No Growth Detected	
	TOTAL		NM³/H	11792		11761		11761		6070		5693	
PROCESS CONDITION	TEMPERATURE		°C	32		30		30		30		Downstream Equipment Specification	
	TEMPERATURE		°F	90		86		86		86			
	PRESSURE		kPA(A)	108		170		1309		6998			
	PRESSURE		BARA	1.1		1.7		13.1		70.0			
	PRESSURE		PSIA	15.7		24.7		189.9		1015.0			
	PRESSURE		PSIG	1.0		10.0		175.2		1000.3			

Figure 17 - Process Flow Diagram – Landfill Gas

7.2.2 Financials

Utilizing assumption B for capital expenditures, the following data was input into the financial model:

Capital Expenditure (Year 0): $11,812,500
Annual Operating Expenditure (Year 1): $2,601,000
Compressor Replacement (Year 10): $2,913,397
Biomethane Sales Price (Year 0): $8/GJ
Biogas Purchase Price: $0/GJ

The resulting financial measures are:

Net Present Value (NPV): $71 M at assumptions stated above
Internal Rate of Return (IRR): 58% at assumptions stated above

Cash flow completed for Years 0 to 20 can be found in Appendix H.

7.2.3 Sensitivity Analysis

In order to address the uncertainty in the estimates for Initial Capital Investment, and Annual Operating Expenditure, sensitivity analysis was completed. The original estimates were compared to the original estimate minus 25%, and the original estimate plus 25%. The resulting affects on NPV and IRR can be seen in Table 45 and Table 46.

		Initial Capital Investment		
		$ 8,859,375	$ 11,812,500	$ 14,765,625
Annual	$ 1,912,500	$ 78,324,539	$ 76,524,791	$ 74,725,043
Operating	$ 2,550,000	$ 72,907,272	$ 71,107,524	$ 69,307,776
Expenditure	$ 3,187,500	$ 67,490,005	$ 65,690,256	$ 63,890,508

Table 44 - Case Study 2 NPV Sensitivity Capital Investment vs. Operating Expenditure

		Initial Capital Investment		
		$ 8,859,375	$ 11,812,500	$ 14,765,625
Annual	$ 1,912,500	80.90%	62.05%	50.70%
Operating	$ 2,550,000	76.11%	58.44%	47.79%
Expenditure	$ 3,187,500	71.31%	54.82%	44.88%

Table 45 - Case Study 2 IRR Sensitivity Capital Investment vs. Operating Expenditure

Biomethane sales price and biogas purchase price are also two factors that have a large influence on the financial model. In the calculations, the biomethane sales price is estimated at $8/GJ based on discussions with industry. The biogas sales price was

assumed to be $0/GJ. The impacts on IRR and NPV by changing the biomethane sales price or biogas purchase price can be seen in Table 46 and Table 47.

	2009 Biomethane Sales Price ($CDN/GJ)				
	$ 6	$ 7	$ 8	$ 9	$ 10
NPV	$ 45,864,017	$ 58,485,771	$ 71,107,524	$ 83,729,277	$ 96,351,030
IRR	41.48%	50.00%	58.44%	66.84%	75.22%

Table 46 - Biomethane Sales Price Sensitivity Analysis Case Study 2

	2009 Biogas Price ($CDN/GJ)				
	$ -	$ 1	$ 2	$ 3	$ 4
NPV	$ 71,107,524	$ 57,083,354	$ 43,059,183	$ 29,035,013	$ 14,945,583
IRR	58.44%	49.05%	39.57%	29.88%	19.58%

Table 47 - Biogas Purchase Price Sensitivity Analysis Case Study 2

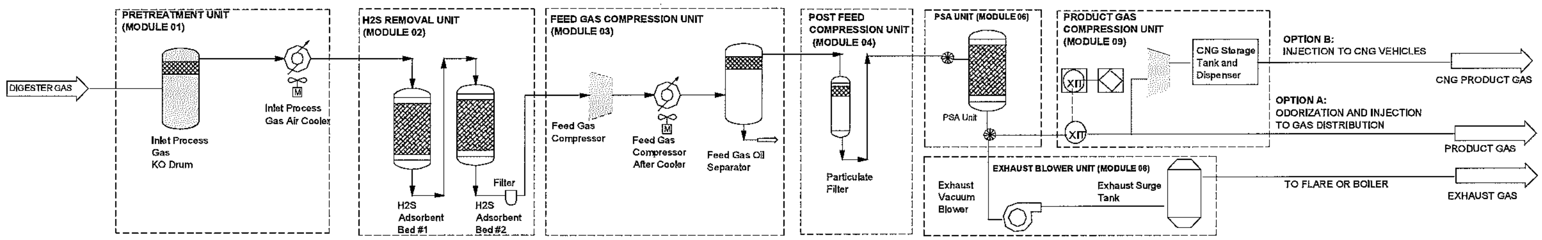
7.3 Case Study 3 – Biogas from Anaerobic Digestion of Clean Organics

Organics that are a product of industrial or agricultural processes are not typically contaminated with inorganic material in the same way as SSO. Case Study 3 proposes one possible upgrading design for the resulting biogas from a theoretical anaerobic digester of dairy waste. This design also includes the requirements for injection of the output biomethane into the natural gas distribution system.

Due to the amount of existing data on biogas composition from anaerobic digesters of dairy waste, gas samples were not taken to determine a design biogas composition. Past experience on the part of the design consultant with biogas upgrading plant design was leveraged to produce a typical biogas composition. Other data utilized for the design is also theoretical.

7.3.1 Process Flow

Figure 18 presents the process flow diagram for Case Study 3. The process flow diagram includes the modules required to upgrade the biogas to meet biomethane composition requirements. The "Stream Flows" section of Figure 18 presents the gas composition as the gas is upgraded through each of the Modules. This design includes nine modules. The power module and instrument air module are not presented in Figure 18 as they do not affect the gas composition



STREAM FLOWS				1		2		3		4		5		6	
NCMH - MOL%				TOTAL FEED		FEED TO H2S REMOVAL UNIT		FEED TO COMPRESSOR		FEED TO PSA		PRODUCT		EXHAUST	
PROCESS STREAM	STREAM COMPOSITION		MW												
	METHANE (WET BASIS)	CH4	16.0	153.3	62.1%	153.3	63.7%	153.3	63.7%	153.3	64.8%	131.8	97.0%	21.5	20.7%
	CARBON DIOXIDE	CO2	44.0	82.5	33.5%	82.5	34.3%	82.5	34.3%	82.5	34.9%	4.1	3.0%	78.4	75.6%
	WATER	H2O	18.0	3.4 kg/m^3		3.1 kg/m^3		3.1 kg/m^3		3.0 kg/m^3		< 0.2 mg/m^3		> 2.8 kg/m^3	
	WATER (VOLUME %)	H2O	18.0	4.4%		2.1%		2.1%		0.4%		< 2 x 10^{-8} %		3.7%	
	IMPURITIES														
	HYDROGEN SULPHIDE	H2S		1000 ppmv		1000 ppmv		< 50 ppmv		< 50 ppmv		< 5 ppmv		< 50 ppmv	
	SULPHUR DIOXIDE	SO2		0.032 ppmv		0.032 ppmv		< 0.003 ppmv		< 0.003 ppmv		< 0.003 ppmv		< 0.003 ppmv	
	HALOGENATED COMPOUNDS			0.021 ppmv		0.021 ppmv		< 0.021 ppmv		< 0.021 ppmv		< 0.021 ppmv		< 0.021 ppmv	
	VOC's			0.24 ppmv		0.24 ppmv		< 0.24 ppmv		< 0.24 ppmv		< 0.05 ppbv		< 0.20 ppmv	
	TOTAL		NM³/H	236		236		236		236		136		100	
PROCESS CONDITION	TEMPERATURE		°C	32		30		30		30		30		Downstream Equipment Specification	
	TEMPERATURE		°F	90		86		86		86		86			
	PRESSURE		kPA(A)	108		205		170		1135		1485			
	PRESSURE		BARA	1.1		2.1		1.7		11.4		14.9			
	PRESSURE		PSIA	15.7		29.7		24.7		164.6		215.4			
	PRESSURE		PSIG	1.0		15.0		10.0		149.9		200.7			

Figure 18 - Process Flow Diagram - Biogas from Anaerobic Digestion of Clean Organics

7.3.2 Financials

Utilizing assumption B for capital expenditures, the following data was input into the financial model:

Capital Expenditure (Year 0): $1,988,500
Annual Operating Expenditure (Year 1): $276,431
Compressor Replacement (Year 10): $204,791
Biomethane Sales Price (Year 0): $8/GJ
Biogas Purchase Price: $0/GJ

The resulting financial measures NPV and IRR were both negative using the above data. Therefore the analysis was repeated using the assumption that the biomethane was sold as Compressed Natural Gas (CNG) for vehicle fuelling purposes.

The revised assumptions are:

Capital Expenditure (Year 0): $2,505,500
Annual Operating Expenditure (Year 1): $315,191
Compressor Replacement (Year 10): $741,149
Biomethane Sales Price (Year 0): $22/GJ
Biogas Purchase Price: $0/GJ

The resulting financial measures utilizing the CNG assumptions are:

Net Present Value (NPV): $1.7 M at assumptions stated above
Internal Rate of Return (IRR): 14% at assumptions stated above

Cash flow completed for Years 0 to 20 can be found in Appendix H.

7.3.3 Sensitivity Analysis

In order to address the uncertainty in the estimates for Initial Capital Investment, and Annual Operating Expenditure, sensitivity analysis was completed. The original estimates were compared to the original estimate minus 25%, and the original estimate plus 25%. The resulting affects on NPV and IRR can be seen in Table 48 and Table 49.

		Initial Capital Investment		
		$ 1,879,125	$ 2,505,500	$ 3,131,875
Annual	$ 231,758	$ 2,747,184	$ 2,321,303	$ 1,952,517
Operating	$ 309,011	$ 2,072,801	$ 1,665,139	$ 1,329,285
Expenditure	$ 386,264	$ 1,401,367	$ 1,053,809	$ 678,942

Table 48 - Case Study 3 with CNG NPV Sensitivity Capital Investment vs. Operating Expenditure

		Initial Capital Investment		
		$ 1,879,125	$ 2,505,500	$ 3,131,875
Annual	$ 231,758	21.55%	16.47%	13.49%
Operating	$ 309,011	18.23%	13.93%	11.42%
Expenditure	$ 386,264	14.80%	11.41%	9.12%

Table 49 - Case Study 3 with CNG IRR Sensitivity Capital Investment vs. Operating Expenditure

Biomethane sales price and biogas purchase price are also two factors that have a large influence on the financial model. In the calculations, the biomethane sales price is estimated at $8/GJ based on discussions with industry. The biogas sales price was assumed to be $0/GJ. The impacts on IRR and NPV by changing the biomethane sales price or biogas purchase price can be seen in Table 50 and Table 51.

	2009 Biomethane Sales Price ($CDN/GJ)				
	$ 19	$ 20	$ 21	$ 22	$ 23
NPV	$ 862,833	$ 1,149,233	$ 1,440,152	$ 1,665,139	$ 1,996,364
IRR	10.59%	11.82%	13.02%	13.93%	15.25%

Table 50 - Biomethane Sales Price Sensitivity Analysis Case Study 3 with CNG

	2009 Biogas Price ($CDN/GJ)				
	$ -	$ 1	$ 2	$ 3	$ 4
NPV	$ 1,665,139	$ 1,402,431	$ 1,100,803	$ 781,284	$ 460,588
IRR	13.93%	12.87%	11.60%	10.22%	8.77%

Table 51 - Biogas Purchase Price Sensitivity Analysis Case Study 3 with CNG

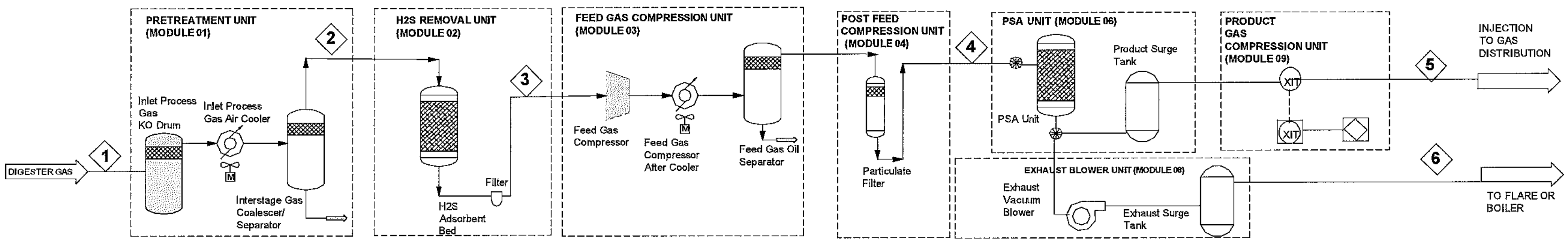
7.4 Case Study 4 – Biogas from Wastewater Treatment Plant

Wastewater treatment plants may employ anaerobic digestion to treat residual solids. One by-product of this process is biogas. Case Study 4 proposes one possible upgrading design for the resulting biogas from a wastewater treatment plant. This design also includes the requirements for injection of the output biomethane into the natural gas distribution system.

In order to determine an appropriate biogas composition, biogas samples were collected at a wastewater treatment plant. The remaining data utilized was theoretical.

7.4.1 Process Flow

Figure 19 presents the process flow diagram for Case Study 4. The process flow diagram includes the modules required to upgrade the biogas to meet biomethane composition requirements. The "Stream Flows" section of Figure 19 presents the gas composition as the gas is upgraded through each of the Modules. This design includes eight modules. The power module and instrument air module are not presented in Figure 19as they do not affect the gas composition.



STREAM FLOWS NCMH - MOL%				1 TOTAL FEED		2 FEED TO H2S REMOVAL UNIT		3 FEED TO COMPRESSOR		4 FEED TO PSA		5 PRODUCT		6 EXHAUST	
PROCESS STREAM	STREAM COMPOSITION		MW												
	METHANE (WET BASIS)	CH4	16.0	1427.8	57.8%	1427.8	59.2%	1427.8	59.2%	1427.8	60.3%	1199.4	98.0%	228.4	19.4%
	CARBON DIOXIDE	CO2	44.0	932.2	37.8%	932.2	38.7%	932.2	38.7%	932.2	39.4%	24.5	2.0%	907.7	76.9%
	WATER	H2O	18.0	3.4 kg/m3		3.0 kg/m3		3.0 kg/m3		3.1 kg/m3		< 0.2 mg/m³		> 2.8 mg/m³	
	WATER (VOLUME %)	H2O	18.0	4.4%		2.1%		2.1%		0.3%		< 2 x 10^{-8} %		3.7%	
	IMPURITIES														
	HYDROGEN SULPHIDE	H2S		190 ppmv		190 ppmv		< 50 ppmv		< 50 ppmv		< 5 ppmv		< 50 ppmv	
	SULPHUR DIOXIDE	SO2		< 0.01 ppmv		< 0.01 ppmv		< 0.01 ppmv		< 0.01 ppmv		< 0.01 ppmv		< 0.01 ppmv	
	MERCAPTAN			0.82 ppmv		0.82 ppmv		< 0.05 ppmv		< 0.05 ppmv		< 0.05 ppmv		< 0.05 ppmv	
	SILOXANES			24.6 ppmv		24.6 ppmv		< 24.6 ppmv		< 24.6 ppmv		< 0.5 ppmv Si		> 24 ppmv Si	
	VOC's			52 ppmv		52 ppmv		< 52 ppmv		< 52 ppmv		< 0.05 ppbv		> 51 ppmv	
	TOTAL		NM³/H	2360		2360		2360		2360		1224		1136	
PROCESS CONDITION	TEMPERATURE		°C	32		30		30		30		30		Downstream Equipment Specification	
	TEMPERATURE		°F	90		86		86		86		86			
	PRESSURE		kPA(A)	108		205		170		1480		1485			
	PRESSURE		BARA	1.1		2.1		1.7		14.8		14.9			
	PRESSURE		PSIA	15.7		29.7		24.7		214.7		215.4			
	PRESSURE		PSIG	1.0		15.0		10.0		200.0		200.7			

Figure 19 - Process Flow Diagram - Biogas from Wastewater Treatment Plant

7.4.2 Financials

Utilizing assumption B for capital expenditures, the following data was input into the financial model:

Capital Expenditure (Year 0): $4,170,500
Annual Operating Expenditure (Year 1): $682,025
Compressor Replacement (Year 10): $736,273
Biomethane Sales Price (Year 0): $8/GJ
Biogas Purchase Price: $0/GJ

The resulting financial measures are:

Net Present Value (NPV): $12 M at assumptions stated above
Internal Rate of Return (IRR): 33% at assumptions stated above

Cash flow completed for Years 0 to 20 can be found in Appendix H.

7.4.3 Sensitivity Analysis

In order to address the uncertainty in the estimates for Initial Capital Investment, and Annual Operating Expenditure, sensitivity analysis was completed. The original estimates were compared to the original estimate minus 25%, and the original estimate plus 25%. The resulting affects on NPV and IRR can be seen in Table 52 and Table 53.

		Initial Capital Investment		
		$ 3,127,875	$ 4,170,500	$ 5,213,125
Annual	$ 501,489	$ 14,042,539	$ 13,407,123	$ 12,771,708
Operating	$ 668,652	$ 12,622,044	$ 11,986,628	$ 11,351,212
Expenditure	$ 835,814	$ 11,201,548	$ 10,566,132	$ 9,916,279

Table 52 - Case Study 4 NPV Sensitivity Capital Investment vs. Operating Expenditure

		Initial Capital Investment		
		$ 3,127,875	$ 4,170,500	$ 5,213,125
Annual	$ 501,489	46.29%	35.91%	29.58%
Operating	$ 668,652	42.67%	33.14%	27.32%
Expenditure	$ 835,814	39.02%	30.35%	24.99%

Table 53 - Case Study 4 IRR Sensitivity Capital Investment vs. Operating Expenditure

Biomethane sales price and biogas purchase price are also two factors that have a large influence on the financial model. In the calculations, the biomethane sales price is estimated at $8/GJ based on discussions with industry. The biogas sales price was

assumed to be $0/GJ. The impacts on IRR and NPV by changing the biomethane sales price or biogas purchase price can be seen in Table 54 and Table 55.

	2009 Biomethane Sales Price ($CDN/GJ)				
	$ 6	$ 7	$ 8	$ 9	$ 10
NPV	$ 6,822,993	$ 9,428,803	$ 11,986,628	$ 14,544,453	$ 17,102,278
IRR	22.71%	28.09%	33.14%	38.10%	43.01%

Table 54 - Biomethane Sales Price Sensitivity Analysis Case Study 4

	2009 Biogas Price ($CDN/GJ)				
	$ -	$ 1	$ 2	$ 3	$ 4
NPV	$ 11,986,628	$ 9,144,600	$ 6,269,747	$ 3,450,476	$ 595,784
IRR	33.14%	27.52%	21.59%	15.45%	8.26%

Table 55 - Biogas Purchase Price Sensitivity Analysis Case Study 4

7.5 Summary of Project Specific Designs

It is apparent from the theoretical designs and corresponding financial analysis, that biogas upgrading to biomethane and injection into the natural gas distribution or transmission system may be a viable business model. The financials for the four case studies are summarized in Table 56.

Case Study	1	2	3	3 with CNG	4
Biogas Source	AD of SSO	Landfill	AD of Clean Organics	AD of Clean Organics	WWTP
Biomethane Energy Content (GJ/day)	590	4,854	107	107	984
Total Capital Investment	$4,147,500	$11,812,500	$1,988,500	$2,505,500	$4,170,500
Total Annual Operating Expenditures	$798,707	$2,550,000	$271,011	$309,011	$668,652
Compressor Replacement Cost (2009 dollars)	$445,000	$2,390,000	$168,000	$608,000	$604,000
NPV	$2,502,461	$71,107,524	($1,357,146)	$1,665,139	$11,986,628
IRR	13%	58%	-6%	14%	33.14%

Table 56 - Summary of Financials for Project Specific Designs

8.0 Biomethane Quality Monitoring

At existing biomethane injection facilities in North America and Europe, different approaches have been taken by the biomethane supplier and the accepting utility in order to ensure that the biomethane injected into the distribution or transmission grid is of acceptable quality. Design choices are made on a case by case basis, and are often dependant upon the accepting utilities comfort level with biomethane. Other criteria that often impact design choices include:

- Volume of biomethane to be injected
- Maximum volume percentage of biomethane in natural gas system
- Sensitivity of end use equipment in area surrounding injection point

In 2008, Electrigaz published a biogas upgrading feasibility study commissioned by the BC Innovation Council. As part of this study, Electrigaz documented two approaches to biomethane injection and monitoring: a simple system (Figure 20) and a complex system (Figure 21). Electrigaz estimated that the simple system would cost between $50,000 and $100,000 not including compressors. The complex system would cost between $100,000 and $400,000, which includes a redundant compressor. These costs and systems do not include redundant monitoring that may be undertaken by the accepting utility.[8]

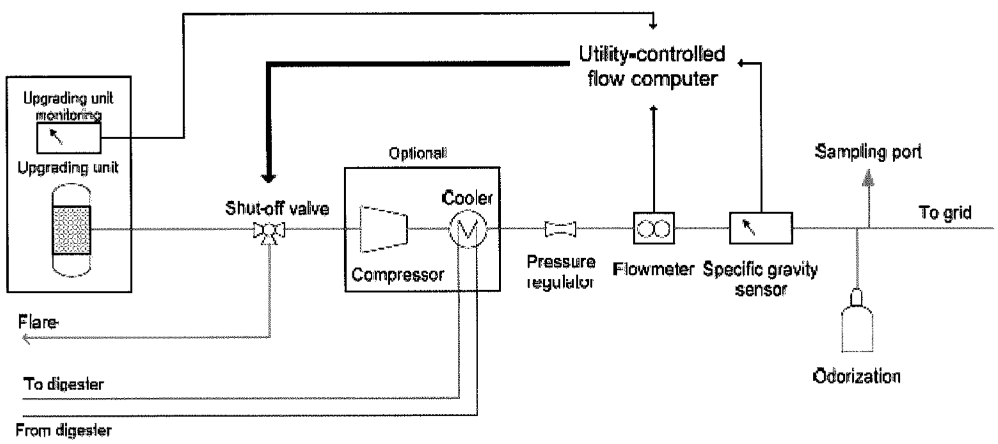


Figure 20 - Simple Injection and Monitoring Process Flow Diagram[8]

[8] Electrigaz, "Feasibility Study – Biogas upgrading and grid injection in Fraser Valley, British Columbia'" June 2008

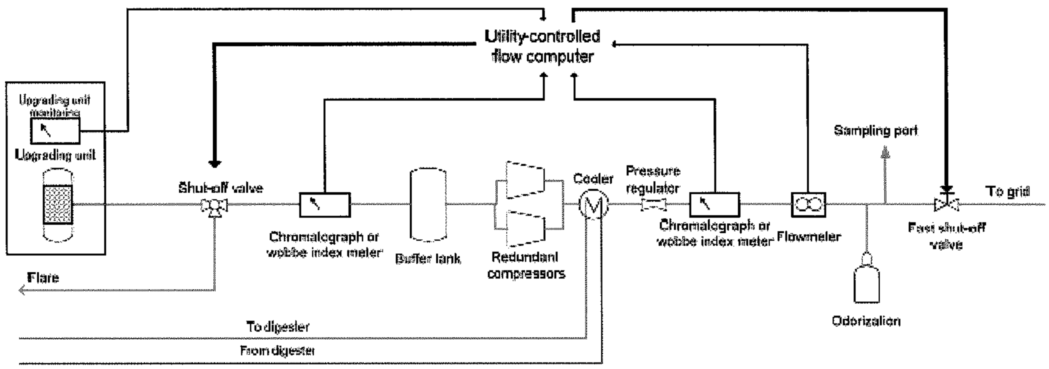


Figure 21 - Complex Injection and Monitoring Process Flow Diagram[8]

In the 2009 report published by GERG, Appendix B, it is recommended that an assessment of the biogas should be undertaken to ensure that unnecessary measurements are not specified upon biomethane quality. Trace components should only be checked periodically if they are below the limits set in the biomethane quality specification. For components that are measured continuously, it is recommended that the measurement system be calibrated daily with certified test gases, as well as completing annual maintenance. GERG references the Electigaz study and recommends that a dew point meter also be installed, at a cost of approximately 1200€. Also, measures to ensure that off-spec gas does not enter the grid are recommended (chromatographs to detect gas quality, buffering tank, recirculation system to the inlet of gas upgrading). In Table 57, existing regulations and recommendations for continuous monitoring are documented at the time of the report. Continuous monitoring for the purposes of Table 57 is defined as at least twice a day, but in some cases every 15 minutes. It is also noted that limits for trace components must be realistic values.[1]

	Germany	France	Netherlands	Switzerland	Canada	Sweden
Responsibility						
Grid owner	X					
Producer		X	X	X	X	X
Obliged						
Wobbe	X	X	X			X (1)
Calorific value	X(1)	X(1)			X	
Density		X			X	
Methane			X	X		X (1)
H_2S	X	X	X		X	X(2)
CO_2		X	X	X	X	X(3)
O_2	X		X	X	X	X(3)
N_2			X			X(3)
H_2	X					
Temp.			X			
Pressure			X			
Water dewpoint	X	X	X	X	X	X(4)
THT		X				
Octane number						X(5)
Accuracy requirements	Calibrated measurement	Methods indicated 1: according to ISO 6976	Not yet specified			1: ISO 6974 and 6976 2: ISO 6326 3: ISO 6974 4: ISO 10101 5: ISO 15403

Table 57 - Biomethane component monitoring by Country[1]

In Switzerland, gas quality monitoring requirements are regulated and specify which components must be monitored continuously and which components must be monitored periodically. Carbon dioxide and methane are monitored using non-dispersive infrared (NDIR) analyzers, and hydrogen sulphide and oxygen are monitored using electro-chemical sensors.[1]

Quality Monitoring	**Continuous**	**Periodic**
	CH_4 O_2 Dew point CO_2	H_2S GC analysis of raw and product gas Trace elements

Table 58 - Swiss Biomethane Quality Monitoring[1]

Based on the biomethane quality specifications outlined in **Error! Reference source not found.**, monitoring could be completed using an online gas chromatograph and offline analysis for trace components. Online gas chromatography could be utilized to monitor major hydrocarbons, carbon dioxide, nitrogen, oxygen, hydrogen sulphide, total sulphur and VOCs. Online analysis for water vapour could be accomplished utilizing electrolytic sensors. Offline analysis should be utilized for components with low concentrations that require a lower detection limit, such as siloxanes. In order to obtain the necessary detection limit for siloxanes, collection of samples utilizing methanol impingers and subsequent analysis using GC-MS could be employed. Calculations for interchangeability indices can be completed utilizing the composition data obtained through online analysis.

In some installations, the gas quality monitoring system is duplicated; one system owned and operated by the biogas upgrading site, and one system owned and operated by the accepting utility.

Alarm and shut down levels for composition can be established and programmed into the monitoring system in order to ensure that off spec gas is not injected into the natural gas distribution or transmission system.

9.0 Conclusions

The implementation of biogas upgrading to biomethane for injection into the natural gas distribution system provides an environmental opportunity to capture methane that may otherwise be released to the atmosphere, as well as an economic opportunity. Biomethane injection facilities have been in operation in North America for over two decades, with over twenty sites currently injecting into the natural gas system. The knowledge developed at these plants can be leveraged to ensure future success of biomethane facilities. For the purposes of this project, gas samples were retrieved from four biomethane injection facilities, each with different upgrading technologies, over a five month period. This allowed data to be interpreted for variation in upgrading technology and time variation of the biogas input stream.

Interchangeability analysis for biomethane was completed for Enbridge Gas Distributions (EGD) territory and demonstrated that biomethane can be successfully accommodated. Interchangeability of 100% biomethane supplies with 100% historical natural gas data from EGD territory demonstrate that biomethane sites designed for direct injection will not pose issues for properly tuned end use equipment performance within EGD territory. Interchangeability analysis was also performed with potential future gas supplies. Based on the worst case conditions, interchangeability between lower Wobbe number biomethane and higher Wobbe number gases (LNG, shale gas), would require some degree of blending. This is an unlikely scenario, though, as new supplies will probably be blended with traditional natural gas supplies.

In order to address health and safety concerns regarding trace contaminants in biomethane and natural gas, the strictest published exposure limiting values from the Ontario Health and Safety act were referenced, followed by published limits from the Occupation Safety and Health Administration (OSHA). For the samples from the sites visited, statistical calculations using t-distribution analysis show that, even with the given sample size, the probability that the process means for natural gas and biomethane plants that are designed for direct injection will be under exposure limiting values is high.

For all valid samples, mercury, lead and arsenic were below detection limit in the biomethane samples. It is also worth noting that PCBs were below detection limits in the biomethane samples as well.

Biological analysis was carried out on biomethane and natural gas streams, and for the samples retrieved, the density of biologicals was similar between the biomethane and natural gas. Total Live Bacteria was completed using MPN, and resulted in biomethane results ranging from no growth detected to 1.25E+03/100scf, and from no growth detected to 5.46E+05/100scf in the natural gas samples. Total Bacteria (live plus dead) via qPCR resulted in 2.46E+04/100scf to 2.22E+07/100scf in the biomethane samples, and 6.68E+05/100scf to 7.39E+06/100scf in the natural gas samples. The analysis of types of bacteria identified typical environmental isolates, and isolates associated with the human body. Aerobic spores were found in one of the natural gas samples at a quantity of 1.79E+03/100scf. Spores were found in biomethane samples from only one landfill site and one wastewater treatment plant, ranging from below detection limit to 1.21E+04/100scf.

To ensure that pipeline assets are not negatively impacted, local tariff gas quality criteria should be adhered to for direct injection biomethane sites. For the samples from the sites visited, statistical calculations show that, even with a small sample size, the degree of probability that the process means for natural gas and biomethane plants that are designed for direct injection will be within the TCPL transportation tariff criteria values is high. In certain instances, considerations of blending could be utilized to meet the transportation tariff gas quality criteria. Biological analysis included the identification of corrosion-causing bacteria within natural gas and biomethane. Total acid producing bacteria, and total iron-oxidizing bacteria are of similar density in natural gas and biomethane. Sulfate-reducing bacteria were below the detection limit in all of the samples.

Quality control criteria should be established on a site by site basis. Based on literature search and existing sites, it is expected that quality monitoring equipment can range from $50,000 to $400,000. Online and offline analysis should be considered as part of a quality control strategy.

By completing theoretical designs for upgrading plants and the associated financial analysis, certain trends can be seen. Three of the four theoretical designs offered better than utility rates of return. As shown by the case studies, a factor of scale improves the economic viability of these plants, with larger flow rates resulting in higher rates of return. It can also be noted that hydrogen sulphide concentrations in the incoming biogas streams can have a material impact on both the capital and operating costs of the upgrading plant. It should also be noted that the financial analysis was done under some key assumptions about permitting processes, labour rates, availability of some facilities at the construction sites, etc. These assumptions have to be validated on a per-project basis in determining the financial viability of each biogas upgrade undertaking.

Appendix A
Existing Biomethane Injection Facilities within North America

Site	Site Location	Biomass Source	In Operation Since	Site Owner or Operator	Accepting Pipeline	CO2 Removal Technology	Biogas Flow Rate Design Point
Rumpke Landfill	Ohio	Landfill	1: 1986 2: 1995 3: 2007	Montauk GSF	Duke Energy (local)	PSA	1: 6 MMSCFD 2: 3 MMSCFD 3: 6 MMSCFD
Monroeville	Pennsylvania	Landfill	2004	Montauk-Magellan	Equitable (local)	Membrane	5 MMSCFD
Valley	Pennsylvania	Landfill	2004	Montauk-Magellan	Equitrans (transmission)	Membrane	5 MMSCFD
EBI Energie	Quebec	Landfill	2003	EBI	TQM (transmission)	Membrane	5 MMSCFD
Greentree	Pennsylvania	Landfill	2007	Beacon Generating and American Exploration	National Fuel Gas	Membrane	12 MMSCFD
Johnson County	Kansas	Landfill	2001	EIF KC Landfill Gas	Kansas Pipeline	Solvent	8 MMSCFD
Fort Smith Landfill	Arkansas	Landfill	2005	SouthTex Renewables and Cambrian Energy Development	Arkansas Oklahoma Gas Corp	Solvent Note: Use propane blending to achieve >975 BTU/scf	2.5 MMSCFD
Jefferson Davis Parish Landfill	Louisiana	Landfill	2008	SouthTex Renewables	Gulf South Pipeline	Solvent	1500 scfm (≈2 MMSCFD)

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Fresh Kills	New York	Landfill	1982	Montauk	Keyspan	Solvent	14 MMSCFD
McCarty Road	Texas	Landfill	1986	Montauk GSF	Centerpoint (local)	Solvent	9 MMSCFD
Imperial	Pennsylvania	Landfill	2007	Beacon Generating	National Fuel Gas	Membrane	6 MMSCFD
Laurel Highlands	Pennsylvania	Landfill	2006	Keystone Renewable Energy and Leaf Clean Energy	Dominion East Ohio Gas	Membrane	4 MMSCFD
Carter Valley	Tennessee	Landfill	2009	TenGasCo	Eastman Chemical Co	Membrane	biomethane injected: 400 MCF/day
McCommas Bluff	Texas	Landfill	2000	Dallas Clean Energy	Atmos Energy	PSA	9 MMCFD
South Hills	Pennsylvania	Landfill	2008	Green Gas Energy	Equitrans (transmission)	PSA	inlet: 1600 scfm outlet: 991 MMBTU/day
Westside	Michigan	Landfill	1999	DTE Biomass Energy	(local)	?	4.5 MMSCFD
Pinnacle Road & Stony Hollow	Ohio	Landfill	2003	DTE Biomass Energy	ProLiance Energy	Solvent	5.4 MMSCFD

Shade	Pennsylvania	Landfill	2007	Keystone Renewable Energy and Leaf Clean Energy	Equitable Gas (local)	Membrane	4 MMSCFD
Southern Alleghenies	Pennsylvania	Landfill	2007	Keystone Renewable Energy and Leaf Clean Energy	Equitable Gas (local)	Membrane	2 MMSCFD
Oak Grove	Georgia	Landfill	2008	Renewable Solutions Group and Republic Services	Municipal Gas facilities in Winder and Buford, GA	Membrane	3.5 MMSCFD
Greenwood Farms	Texas	Landfill	2009	SouthTex Renewables	Serving Smith County	?	1.44 MMSCFD
Live Oak	Georgia	Landfill	2009	Jacoby Energy Development	Atlanta Gas and Light	Membrane	7.9 MMSCFD
Oklahoma	Oklahoma	Landfill	2008	Timberline	Southern Star	Membrane	biomethane injected: 550,000 Dth/year
Seneca	Washington	Landfill	2009	Bio Energy	Puget Sound Energy	?	biomethane injected: 4.5 MMCFD

South Treatment Plant	Washington	WWTP	?	King County	Northwest Pipeline to Puget Sound Energy	Water Wash	≈1000 scfm (≈1.4 MMSCFD)
Scenic View Dairy	Michigan	Dairy Waste	2007	Scenic View Dairy (designed by Phase 3 Renewables)	Michigan Gas Utilities	PSA	150 scfm
Vintage	California	Dairy Waste	2008	BioEnergy Solutions	PG&E	PSA	biomethane injected: 3 BCF/year
Huckabay Ridge	Texas	Manure and Agricultura l Waste	2008	Microgy	Enterprise (sold to PG&E)	?	biomethane injected: 2,000 MMBtu/day
Emerald	Wisconsin	Manure	2006	Emerald Dairy	CNG delivered by truck to Northern Natural Gas Pipeline	?	biomethane injected: 100 MCF/day

Appendix B
GERG Biogas Injection: Current Practices and Recommendations

Appendix C
Characterizing Anaerobic Digester Gas

Appendix D
Biogas, Biomethane, and Natural Gas Sampling and Laboratory Analysis

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Appendix E
AFFSET Report
Executive Summary

Appendix F
Biomethane Interchangeability Study

Appendix G
Biogas Upgrading Plant Design Study

Appendix H
Financials

1.0 Assumptions

1.1 Biogas Purchase Price

1.1.1 Biogas would be purchased by owner of upgrading plant from the landfill or AD owner (20 year fixed price contract)

1.1.2 Price of biogas in $/GJ and would increase with inflation (estimated at 2%)

1.1.3 $/GJ would be back calculated based on cost of clean up, sale price of biomethane, and required return on investment

1.1.4 Payment would be based on flow rate meter and heating value prior to in injection of biomethane (these assets would be required for injection of biomethane)

1.2 Biomethane Sales Price

1.2.1 Biomethane sale price would be set out in contract with purchaser – estimated at $8/GJ for first year

1.2.2 Biomethane sale price would increase with inflation (estimated at 2%)

1.3 Capital Expenditures

1.3.1 Ownership includes upgrading, compression, and pipeline assets

1.3.2 Ownership does not include the front end process (i.e. landfill, gas collection system, anaerobic digester)

1.3.3 Capital expenditures based on data from design study

1.3.4 Gas monitoring equipment estimated at $250,000

1.3.5 Building permits estimated at $52,500 based on design study

1.3.6 Excavating and grading estimated at $40,000 based on Enbridge fuel cell site

1.3.7 Geological survey estimated at $10,000 based on Enbridge fuel cell site

1.3.8 The asset life is 20 years (except compressor – see below)

1.3.9 Capitalization of interest during construction not considered

1.3.10 Capital structure is assumed to be 64% Debt and 36% Equity

1.3.11 Cost of Capital (before tax) is assumed to be 7% for debt and 10% for equity

1.3.12 Future changes to cost of capital not considered

1.4 Operating Expenditures

1.4.1 Data from design study

1.4.2 Disposal costs for adsorbent based on mean disposal cost of $0.55/lb as per design study ($0.30/lb to $0.80/lb) – this cost will need to be negotiated with a disposal company and will be dependant upon transportation distance and hazard level of contaminant (exception for landfill site where if disposal of adsorbent is required, should be in contract that adsorbent will be disposed on in landfill free of charge)

1.4.3 Operating Expenditures expected to increase with inflation (estimated at 2%)

1.4.4 Incremental overheads estimated at 10% of revenues

1.5 Compressor Replacement

1.5.1 Compressor life estimated at approximately 80,000 hours ~ 10 years

1.5.2 Replacement based on original price plus inflation rate of 2% per year

1.6 Tax Calculations

1.6.1 The CCA class for these assets is 43.1, with a CCA rate of 30%

1.6.2 Future changes to income tax not considered

General Assumptions	
Plant Life (Years)	20
Annual Inflation Rate	2%
Incremental Overhead (% of revenues)	10%
Taxes	35.14%
Debt Rate Before Tax	7.00%
Equity rate	10.00%
Debt Portion	64%
Equity Portion	36%
WACC	6.51%

Table 59 - General Financial Assumptions

Case Specific Assumptions	Case Study 1 Biogas from AD of SSO	Case Study 2 Landfill Gas	Case Study 3 Biogas from AD of Clean Organics	Case Study 3 Biogas from AD of Clean Organics with CNG	Case Study 4 Biogas from WasteWater Treatment Plant
Methane % Biogas	58.9%	56.7%	62.1%	62.1%	57.8%
Methane % Biomethane	97.9%	97.5%	97.0%	97.0%	98.0%
Methane Loss	15%	15%	14%	14%	16%
Days of Operation per Year	340	340	340	340	340
Asset Life (Years)	20	20	20	20	20
Biogas Flow Rate (m^3/day)	33,000	283,008	5,664	5,664	56,640
Biogas Flow Rate (m^3/year)	11,220,000	96,222,720	1,925,760	1,925,760	19,257,600
Biomethane Flow Rate (m^3/day)	16,174	132,986	2,934	2,934	26,950
Biomethane Flow Rate (m^3/year)	5,499,330	45,215,176	997,617	997,617	9,162,951
Estimated Energy Conversion (MJ/m^3)	36.9	36.8	36.6	36.6	36.9
Biomethane Energy Content (GJ/day)	**590**	**4,854**	**107**	**107**	**984**
Total Capital Expenditure (2009 dollars, Assumption B)	$ 3,745,000	$ 11,410,000	$ 1,586,000	$ 2,103,000	$ 3,768,000
Gas Monitoring Equipment	$ 250,000	$ 250,000	$ 250,000	$ 250,000	$ 250,000
Building Permits (QuestAir Report Appendix B, Table 33)	$ 52,500	$ 52,500	$ 52,500	$ 52,500	$ 52,500
Excavating, Initial Grading and Final Grading (Ref. Enbridge Fuel Cell Site	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000
Geological Survey (Ref. Enbridge Fuel Cell Site)	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Liquids Disposal & Consumables (? Scope)	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Total Capital Investment	**$ 4,147,500**	**$ 11,812,500**	**$ 1,988,500**	**$ 2,505,500**	**$ 4,170,500**
Annual Operating Expenditures (QuestAir Report)	$ 595,000	$ 2,550,000	$ 165,000	$ 203,000	$ 625,000
Estimated Disposal Costs ($/lb)	$ 0.55	$ 0.55	$ 0.55	$ 0.55	$ 0.55
Disposal Weight of SulphaTreat (lb)	291,010	-	192,747	192,747	79,366
Disposal Weight of Activated Carbon (lb)	79,366	-	-	-	-
Estimated Adsorbent Disposal Costs	$ 203,707	$ -	$ 106,011	$ 106,011	$ 43,652
Total Annual Operating Expenditures	**$ 798,707**	**$ 2,550,000**	**$ 271,011**	**$ 309,011**	**$ 668,652**
Capital Additions					
Compressor Life (Hours)	80,000	80,000	80,000	80,001	80,000
Hours Per Year	8,160	8,160	8,160	8,160	8,160
Compressor Replacement Inverval (Years)	10	10	10	10	10
Compressor Replacement Cost (2009 dollars)	$ 445,000	$ 2,390,000	$ 168,000	$ 608,000	$ 604,000

Table 60 - Case Specific Financial Assumptions

Financial Analysis - Case Study 1 - Biogas Upgrading from Anaerobic Digestion of Source Separated Organics for Grid Injection											
	0	1	2	3	4	5	6	7	8	9	10
Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Inflation Factor	100.00%	102.00%	104.04%	106.12%	108.24%	110.41%	112.62%	114.87%	117.17%	119.51%	121.90%
Capital Investment	$ (4,147,500)										$ (542,453)
Operating Expenditure		$ (814,681)	$ (830,975)	$ (847,594)	$ (864,546)	$ (881,837)	$ (899,474)	$ (917,463)	$ (935,813)	$ (954,529)	$ (973,620)
Estimated Revenue		$ 1,637,920	$ 1,670,679	$ 1,704,092	$ 1,738,174	$ 1,772,938	$ 1,808,396	$ 1,844,564	$ 1,881,456	$ 1,919,085	$ 1,957,466
Depreciation		$ (230,515)	$ (230,515)	$ (230,515)	$ (230,515)	$ (230,515)	$ (230,515)	$ (230,515)	$ (230,515)	$ (230,515)	$ (230,515)
Incremental Overhead		$ (163,792)	$ (167,068)	$ (170,409)	$ (173,817)	$ (177,294)	$ (180,840)	$ (184,456)	$ (188,146)	$ (191,908)	$ (195,747)
Biogas Cost		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
EBIT		$ 428,932	$ 442,121	$ 455,574	$ 469,295	$ 483,292	$ 497,568	$ 512,129	$ 526,982	$ 542,132	$ 557,585
Interest		$ (185,808)	$ (181,276)	$ (176,426)	$ (171,237)	$ (165,684)	$ (159,743)	$ (153,386)	$ (146,585)	$ (139,306)	$ (131,519)
EBT		$ 243,124	$ 260,845	$ 279,148	$ 298,059	$ 317,607	$ 337,824	$ 358,743	$ 380,398	$ 402,826	$ 426,066
Income Tax Payable		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (170,951)	$ (191,949)	$ (180,705)
Future Income Tax Considered		$ (85,434)	$ (91,661)	$ (98,093)	$ (104,738)	$ (111,607)	$ (118,712)	$ (126,062)	$ 28,920	$ 50,396	$ 30,986
Net income		$ 157,690	$ 169,184	$ 181,055	$ 193,321	$ 206,000	$ 219,113	$ 232,681	$ 238,367	$ 261,273	$ 276,347
FCF	$ (4,147,500)	$ 574,013	$ 580,975	$ 587,996	$ 595,073	$ 602,199	$ 609,371	$ 616,582	$ 615,467	$ 631,094	$ 95,928
NPV	$2,502,461										
IRR	13%										
Tax Calculations											
Opening UCC		$ -	$ 3,525,375	$ 2,467,763	$ 1,727,434	$ 1,209,204	$ 846,443	$ 592,510	$ 414,757	$ 290,330	$ 203,231
Capital Additions		$ 4,147,500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 542,453
CCA (Class 43.1)	30%	$ 622,125	$ 1,057,613	$ 740,329	$ 518,230	$ 362,761	$ 253,933	$ 177,753	$ 124,427	$ 87,099	$ 142,337
Taxable Income		$ (148,486)	$ (566,252)	$ (230,666)	$ 10,344	$ 185,361	$ 314,407	$ 411,505	$ 486,486	$ 546,242	$ 514,244
Closing Tax Loss		$ (148,486)	$ (714,738)	$ (945,404)	$ (935,060)	$ (749,699)	$ (435,292)	$ (23,787)	$ -	$ -	$ -
Income Tax Payable		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (170,951)	$ (191,949)	$ (180,705)
Tax Loss Carry Forward		$ (148,486)	$ (566,252)	$ (230,666)	$ 10,344	$ 185,361	$ 314,407	$ 411,505	$ 23,787	$ -	$ -
Future Income Tax Considered		$ (85,434)	$ (91,661)	$ (98,093)	$ (104,738)	$ (111,607)	$ (118,712)	$ (126,062)	$ 28,920	$ 50,396	$ 30,986

	11	12	13	14	15	16	17	18	19	20
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Inflation Factor	124.34%	126.82%	129.36%	131.95%	134.59%	137.28%	140.02%	142.82%	145.68%	148.59%
Capital Investment										
Operating Expenditure	$ (993,092)	$ (1,012,954)	$ (1,033,213)	$ (1,053,877)	$ (1,074,955)	$ (1,096,454)	$ (1,118,383)	$ (1,140,751)	$ (1,163,566)	$ (1,186,837)
Estimated Revenue	$ 1,996,616	$ 2,036,548	$ 2,077,279	$ 2,118,825	$ 2,161,201	$ 2,204,425	$ 2,248,514	$ 2,293,484	$ 2,339,354	$ 2,386,141
Depreciation	$ (240,455)	$ (240,455)	$ (240,455)	$ (240,455)	$ (240,455)	$ (240,455)	$ (240,455)	$ (240,455)	$ (240,455)	$ (240,455)
Incremental Overhead	$ (199,662)	$ (203,655)	$ (207,728)	$ (211,882)	$ (216,120)	$ (220,443)	$ (224,851)	$ (229,348)	$ (233,935)	$ (238,614)
Biogas Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
EBIT	$ 563,407	$ 579,484	$ 595,883	$ 612,610	$ 629,671	$ 647,074	$ 664,824	$ 682,930	$ 701,398	$ 720,235
Interest	$ (147,488)	$ (136,813)	$ (125,391)	$ (113,170)	$ (100,093)	$ (86,100)	$ (71,128)	$ (55,108)	$ (37,967)	$ (19,625)
EBT	$ 415,919	$ 442,671	$ 470,492	$ 499,440	$ 529,579	$ 560,974	$ 593,696	$ 627,822	$ 663,431	$ 700,609
Income Tax Payable	$ (167,045)	$ (195,527)	$ (218,660)	$ (238,183)	$ (255,318)	$ (270,932)	$ (285,638)	$ (299,874)	$ (313,959)	$ (328,123)
Future Income Tax Considered	$ 20,891	$ 39,973	$ 53,330	$ 62,680	$ 69,224	$ 73,806	$ 77,013	$ 79,258	$ 80,829	$ 81,929
Net income	$ 269,765	$ 287,116	$ 305,161	$ 323,937	$ 343,485	$ 363,848	$ 385,071	$ 407,205	$ 430,301	$ 454,415
FCF	$ 657,708	$ 664,385	$ 671,007	$ 677,562	$ 684,032	$ 690,403	$ 696,655	$ 702,768	$ 708,723	$ 714,496
Tax Calculations										
Opening UCC	$ 603,346	$ 422,342	$ 295,640	$ 206,948	$ 144,863	$ 101,404	$ 70,983	$ 49,688	$ 34,782	$ 24,347
Capital Additions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA (Class 43.1)	$ 181,004	$ 126,703	$ 88,692	$ 62,084	$ 43,459	$ 30,421	$ 21,295	$ 14,906	$ 10,435	$ 7,304
Taxable Income	$ 475,370	$ 556,423	$ 622,255	$ 677,811	$ 726,575	$ 771,008	$ 812,857	$ 853,371	$ 893,452	$ 933,760
Closing Tax Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Income Tax Payable	$ (167,045)	$ (195,527)	$ (218,660)	$ (238,183)	$ (255,318)	$ (270,932)	$ (285,638)	$ (299,874)	$ (313,959)	$ (328,123)
Tax Loss Carry Forward	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Future Income Tax Considered	$ 20,891	$ 39,973	$ 53,330	$ 62,680	$ 69,224	$ 73,806	$ 77,013	$ 79,258	$ 80,829	$ 81,929

Figure 22 - Financials for Case Study 1: Biogas from AD of SSO

Financial Analysis - Case Study 2 - Landfill Gas Upgrading for Grid Injection											
	0	1	2	3	4	5	6	7	8	9	10
Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Inflation Factor	100.00%	102.00%	104.04%	106.12%	108.24%	110.41%	112.62%	114.87%	117.17%	119.51%	121.90%
Capital Investment	$ (11,812,500)										$ (2,913,397)
Operating Expenditure		$ (2,601,000)	$ (2,653,020)	$ (2,706,080)	$ (2,760,202)	$ (2,815,406)	$ (2,871,714)	$ (2,929,148)	$ (2,987,731)	$ (3,047,486)	$ (3,108,436)
Estimated Revenue		$ 13,466,888	$ 13,736,226	$ 14,010,950	$ 14,291,169	$ 14,576,993	$ 14,868,533	$ 15,165,903	$ 15,469,221	$ 15,778,606	$ 16,094,178
Depreciation		$ (714,905)	$ (714,905)	$ (714,905)	$ (714,905)	$ (714,905)	$ (714,905)	$ (714,905)	$ (714,905)	$ (714,905)	$ (714,905)
Incremental Overhead		$ (1,346,689)	$ (1,373,623)	$ (1,401,095)	$ (1,429,117)	$ (1,457,699)	$ (1,486,853)	$ (1,516,590)	$ (1,546,922)	$ (1,577,861)	$ (1,609,418)
Biogas Cost		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
EBIT		$ 8,804,294	$ 8,994,678	$ 9,188,870	$ 9,386,945	$ 9,588,982	$ 9,795,060	$ 10,005,260	$ 10,219,663	$ 10,438,354	$ 10,661,419
Interest		$ (826,875)	$ (806,705)	$ (785,123)	$ (762,031)	$ (737,322)	$ (710,883)	$ (682,594)	$ (652,324)	$ (619,936)	$ (585,280)
EBT		$ 7,977,419	$ 8,187,973	$ 8,403,747	$ 8,624,915	$ 8,851,661	$ 9,084,177	$ 9,322,666	$ 9,567,339	$ 9,818,418	$ 10,076,139
Income Tax Payable		$ (2,431,846)	$ (2,069,989)	$ (2,463,356)	$ (2,763,356)	$ (2,998,632)	$ (3,189,256)	$ (3,349,303)	$ (3,488,651)	$ (3,614,239)	$ (3,577,388)
Future Income Tax Considered		$ (371,419)	$ (807,265)	$ (489,720)	$ (267,439)	$ (111,842)	$ (2,924)	$ 73,318	$ 126,688	$ 164,047	$ 36,633
Net income		$ 5,174,154	$ 5,310,719	$ 5,450,670	$ 5,594,120	$ 5,741,187	$ 5,891,997	$ 6,046,681	$ 6,205,376	$ 6,368,226	$ 6,535,384
FCF	$ (11,812,500)	$ 6,715,934	$ 6,832,330	$ 6,950,698	$ 7,071,055	$ 7,193,414	$ 7,317,785	$ 7,444,180	$ 7,572,605	$ 7,703,067	$ 4,922,172
NPV	$71,107,524										
IRR	58%										
Tax Calculations											
Opening UCC		$ -	$ 10,040,625	$ 7,028,438	$ 4,919,906	$ 3,443,934	$ 2,410,754	$ 1,687,528	$ 1,181,269	$ 826,889	$ 578,822
Capital Additions		$ 11,812,500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,913,397
CCA (Class 43.1)	30%	$ 1,771,875	$ 3,012,188	$ 2,108,531	$ 1,475,972	$ 1,033,180	$ 723,226	$ 506,258	$ 354,381	$ 248,067	$ 610,656
Taxable Income		$ 6,920,449	$ 5,890,691	$ 7,010,120	$ 7,863,848	$ 8,533,385	$ 9,075,856	$ 9,531,312	$ 9,927,863	$ 10,285,257	$ 10,180,388
Closing Tax Loss		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Income Tax Payable		$ (2,431,846)	$ (2,069,989)	$ (2,463,356)	$ (2,763,356)	$ (2,998,632)	$ (3,189,256)	$ (3,349,303)	$ (3,488,651)	$ (3,614,239)	$ (3,577,388)
Tax Loss Carry Forward		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Future Income Tax Considered		$ (371,419)	$ (807,265)	$ (489,720)	$ (267,439)	$ (111,842)	$ (2,924)	$ 73,318	$ 126,688	$ 164,047	$ 36,633
Energy Prices											
Biomethane Sales Price ($CDN/GJ)	$ 8.00	$ 8.16	$ 8.32	$ 8.49	$ 8.66	$ 8.83	$ 9.01	$ 9.19	$ 9.37	$ 9.56	$ 9.75
Biogas Purchase Price ($CDN/GJ)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

	11	12	13	14	15	16	17	18	19	20
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Inflation Factor	124.34%	126.82%	129.36%	131.95%	134.59%	137.28%	140.02%	142.82%	145.68%	148.59%
Capital Investment										
Operating Expenditure	$ (3,170,604)	$ (3,234,017)	$ (3,298,697)	$ (3,364,671)	$ (3,431,964)	$ (3,500,604)	$ (3,570,616)	$ (3,642,028)	$ (3,714,868)	$ (3,789,166)
Estimated Revenue	$ 16,416,061	$ 16,744,383	$ 17,079,270	$ 17,420,856	$ 17,769,273	$ 18,124,658	$ 18,487,152	$ 18,856,895	$ 19,234,032	$ 19,618,713
Depreciation	$ (768,291)	$ (768,291)	$ (768,291)	$ (768,291)	$ (768,291)	$ (768,291)	$ (768,291)	$ (768,291)	$ (768,291)	$ (768,291)
Incremental Overhead	$ (1,641,606)	$ (1,674,438)	$ (1,707,927)	$ (1,742,086)	$ (1,776,927)	$ (1,812,466)	$ (1,848,715)	$ (1,885,689)	$ (1,923,403)	$ (1,961,871)
Biogas Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
EBIT	$ 10,835,559	$ 11,067,636	$ 11,304,355	$ 11,545,808	$ 11,792,090	$ 12,043,298	$ 12,299,529	$ 12,560,886	$ 12,827,469	$ 13,099,384
Interest	$ (548,199)	$ (508,521)	$ (466,067)	$ (420,640)	$ (372,034)	$ (320,025)	$ (264,376)	$ (204,831)	$ (141,118)	$ (72,945)
EBT	$ 10,287,361	$ 10,559,115	$ 10,838,288	$ 11,125,168	$ 11,420,056	$ 11,723,272	$ 12,035,154	$ 12,356,055	$ 12,686,351	$ 13,026,439
Income Tax Payable	$ (3,581,182)	$ (3,767,809)	$ (3,929,703)	$ (4,075,167)	$ (4,210,049)	$ (4,338,480)	$ (4,463,392)	$ (4,586,878)	$ (4,710,450)	$ (4,835,210)
Future Income Tax Considered	$ (33,797)	$ 57,336	$ 121,128	$ 165,783	$ 197,041	$ 218,922	$ 234,239	$ 244,960	$ 252,466	$ 257,719
Net income	$ 6,672,382	$ 6,848,642	$ 7,029,714	$ 7,215,784	$ 7,407,048	$ 7,603,714	$ 7,806,001	$ 8,014,137	$ 8,228,367	$ 8,448,949
FCF	$ 7,988,872	$ 8,125,455	$ 8,264,072	$ 8,404,715	$ 8,547,374	$ 8,692,031	$ 8,838,668	$ 8,987,260	$ 9,137,777	$ 9,290,185
Tax Calculations										
Opening UCC	$ 2,881,563	$ 2,017,094	$ 1,411,966	$ 988,376	$ 691,863	$ 484,304	$ 339,013	$ 237,309	$ 166,116	$ 116,281
Capital Additions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA (Class 43.1)	$ 864,469	$ 605,128	$ 423,590	$ 296,513	$ 207,559	$ 145,291	$ 101,704	$ 71,193	$ 49,835	$ 34,884
Taxable Income	$ 10,191,183	$ 10,722,278	$ 11,182,990	$ 11,596,946	$ 11,980,788	$ 12,346,273	$ 12,701,741	$ 13,053,154	$ 13,404,808	$ 13,759,846
Closing Tax Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Income Tax Payable	$ (3,581,182)	$ (3,767,809)	$ (3,929,703)	$ (4,075,167)	$ (4,210,049)	$ (4,338,480)	$ (4,463,392)	$ (4,586,878)	$ (4,710,450)	$ (4,835,210)
Tax Loss Carry Forward	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Future Income Tax Considered	$ (33,797)	$ 57,336	$ 121,128	$ 165,783	$ 197,041	$ 218,922	$ 234,239	$ 244,960	$ 252,466	$ 257,719
Energy Prices										
Biomethane Sales Price ($CDN/GJ)	$ 9.95	$ 10.15	$ 10.35	$ 10.56	$ 10.77	$ 10.98	$ 11.20	$ 11.43	$ 11.65	$ 11.89
Biogas Purchase Price ($CDN/GJ)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Figure 23 - Financials for Case Study 2 - Landfill Gas

Financial Analysis - Case Study 3 - Biogas Upgrading from Anaerobic Digestion of "Clean" Organics for Grid Injection																					
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Inflation Factor	100.00%	102.00%	104.04%	106.12%	108.24%	110.41%	112.62%	114.87%	117.17%	119.51%	121.90%	124.34%	126.82%	129.36%	131.95%	134.59%	137.28%	140.02%	142.82%	145.68%	148.59%
Capital Investment	$ (1,988,500)										$ (204,791)										
Operating Expenditure		(276,431)	(281,960)	(287,599)	(293,351)	(299,218)	(305,202)	(311,306)	(317,532)	(323,883)	(330,361)	(336,968)	(343,707)	(350,581)	(357,593)	(364,745)	(372,040)	(379,481)	(387,070)	(394,812)	(402,708)
Estimated Revenue		297,130	303,073	309,134	315,317	321,623	328,056	334,617	341,309	348,136	355,098	362,200	369,444	376,833	384,370	392,057	399,898	407,896	416,054	424,375	432,863
Depreciation		(108,161)	(108,161)	(108,161)	(108,161)	(108,161)	(108,161)	(108,161)	(108,161)	(108,161)	(108,161)	(111,914)	(111,914)	(111,914)	(111,914)	(111,914)	(111,914)	(111,914)	(111,914)	(111,914)	(111,914)
Incremental Overhead		(29,713)	(30,307)	(30,913)	(31,532)	(32,162)	(32,806)	(33,462)	(34,131)	(34,814)	(35,510)	(36,220)	(36,944)	(37,683)	(38,437)	(39,206)	(39,990)	(40,790)	(41,605)	(42,438)	(43,286)
Biogas Cost		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EBIT		(117,175)	(117,355)	(117,539)	(117,727)	(117,918)	(118,113)	(118,312)	(118,515)	(118,722)	(118,933)	(122,901)	(123,121)	(123,345)	(123,574)	(123,807)	(124,045)	(124,288)	(124,535)	(124,788)	(125,045)
Interest		(139,195)	(135,800)	(132,167)	(128,279)	(124,120)	(119,669)	(114,907)	(109,811)	(104,359)	(98,525)	(92,283)	(85,604)	(78,457)	(70,810)	(62,628)	(53,873)	(44,505)	(34,481)	(23,756)	(12,279)
EBT		(256,370)	(253,155)	(249,706)	(246,006)	(242,038)	(237,782)	(233,219)	(228,326)	(223,081)	(217,459)	(215,184)	(208,725)	(201,802)	(194,384)	(186,435)	(177,918)	(168,792)	(159,016)	(148,543)	(137,325)
Income Tax Payable		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Future Income Tax Considered		90,088	88,959	87,747	86,446	85,052	83,557	81,953	80,234	78,391	76,415	75,616	73,346	70,913	68,307	65,513	62,520	59,314	55,878	52,198	48,256
Net income		(166,281)	(164,196)	(161,959)	(159,559)	(156,986)	(154,225)	(151,266)	(148,092)	(144,690)	(141,044)	(139,569)	(135,379)	(130,889)	(126,077)	(120,922)	(115,397)	(109,479)	(103,138)	(96,345)	(89,069)
FCF	$ (1,988,500)	81,075	79,764	78,369	76,881	75,295	73,605	71,802	69,880	67,830	(139,148)	64,628	62,138	59,482	56,646	53,620	50,389	46,940	43,257	39,324	35,124
NPV	($1,357,146)																				
IRR	-6%																				
Tax Calculations																					
Opening UCC		-	1,690,225	1,183,158	828,210	579,747	405,823	284,076	198,853	139,197	97,438	242,279	169,595	118,717	83,102	58,171	40,720	28,504	19,953	13,967	9,777
Capital Additions		1,988,500	-	-	-	-	-	-	-	-	204,791	-	-	-	-	-	-	-	-	-	-
CCA (Class 43.1)	30%	298,275	507,068	354,947	248,463	173,924	121,747	85,223	59,656	41,759	59,950	72,684	50,879	35,615	24,931	17,451	12,216	8,551	5,986	4,190	2,933
Taxable Income		(446,484)	(652,061)	(496,492)	(386,308)	(307,801)	(251,368)	(210,281)	(179,821)	(156,679)	(169,248)	(175,954)	(147,690)	(125,504)	(107,401)	(91,973)	(78,220)	(65,430)	(53,088)	(40,820)	(28,344)
Closing Tax Loss		(446,484)	(1,098,545)	(1,595,037)	(1,981,345)	(2,289,145)	(2,540,513)	(2,750,794)	(2,930,615)	(3,087,295)	(3,256,542)	(3,432,497)	(3,580,187)	(3,705,691)	(3,813,091)	(3,905,064)	(3,983,284)	(4,048,714)	(4,101,802)	(4,142,622)	(4,170,965)
Income Tax Payable		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tax Loss Carry Forward		(446,484)	(652,061)	(496,492)	(386,308)	(307,801)	(251,368)	(210,281)	(179,821)	(156,679)	(169,248)	(175,954)	(147,690)	(125,504)	(107,401)	(91,973)	(78,220)	(65,430)	(53,088)	(40,820)	(28,344)
Future Income Tax Considered		90,088	88,959	87,747	86,446	85,052	83,557	81,953	80,234	78,391	76,415	75,616	73,346	70,913	68,307	65,513	62,520	59,314	55,878	52,198	48,256
Energy Prices																					
Biomethane Sales Price ($CDN/GJ)	8.00	8.16	8.32	8.49	8.66	8.83	9.01	9.19	9.37	9.56	9.75	9.95	10.15	10.35	10.56	10.77	10.98	11.20	11.43	11.65	11.89
Biogas Purchase Price ($CDN/GJ)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Figure 24 - Financials for Case Study 3 - Biogas from AD of "Clean" Organics

Financial Analysis - Case Study 3 with CNG - Biogas Upgrading from Anaerobic Digestion of "Clean" Organics for Grid Injection																					
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Inflation Factor	100.00%	102.00%	104.04%	106.12%	108.24%	110.41%	112.62%	114.87%	117.17%	119.51%	121.90%	124.34%	126.82%	129.36%	131.95%	134.59%	137.28%	140.02%	142.82%	145.68%	148.59%
Capital Investment	$ (2,505,500)										$ (741,149)										
Operating Expenditure		(315,191)	(321,495)	(327,925)	(334,483)	(341,173)	(347,996)	(354,956)	(362,055)	(369,297)	(376,683)	(384,216)	(391,900)	(399,739)	(407,733)	(415,888)	(424,206)	(432,690)	(441,344)	(450,170)	(459,174)
Estimated Revenue		817,108	833,451	850,120	867,122	884,464	902,154	920,197	938,601	957,373	976,520	996,051	1,015,972	1,036,291	1,057,017	1,078,157	1,099,720	1,121,715	1,144,149	1,167,032	1,190,373
Depreciation		(156,890)	(156,890)	(156,890)	(156,890)	(156,890)	(156,890)	(156,890)	(156,890)	(156,890)	(156,890)	(170,471)	(170,471)	(170,471)	(170,471)	(170,471)	(170,471)	(170,471)	(170,471)	(170,471)	(170,471)
Incremental Overhead		(81,711)	(83,345)	(85,012)	(86,712)	(88,446)	(90,215)	(92,020)	(93,860)	(95,737)	(97,652)	(99,605)	(101,597)	(103,629)	(105,702)	(107,816)	(109,972)	(112,171)	(114,415)	(116,703)	(119,037)
Biogas Cost		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EBIT		263,316	271,720	280,293	289,036	297,955	307,052	316,330	325,795	335,449	345,295	341,758	352,003	362,452	373,111	383,982	395,071	406,382	417,919	429,687	441,690
Interest		(175,385)	(171,107)	(166,529)	(161,631)	(156,390)	(150,782)	(144,782)	(138,362)	(131,492)	(124,141)	(116,276)	(107,860)	(98,855)	(89,220)	(78,911)	(67,879)	(56,076)	(43,446)	(29,932)	(15,472)
EBT		87,931	100,614	113,763	127,405	141,565	156,269	171,548	187,433	203,957	221,154	225,482	244,142	263,597	283,890	305,072	327,192	350,307	374,473	399,755	426,218
Income Tax Payable		-	-	-	-	-	-	-	(94,582)	(108,312)	(80,836)	(63,666)	(92,865)	(115,550)	(133,776)	(148,985)	(162,194)	(174,122)	(185,278)	(196,027)	(206,631)
Future Income Tax Considered		(30,899)	(35,356)	(39,976)	(44,770)	(49,746)	(54,913)	(60,282)	(61,810)	36,642	3,123	(15,568)	7,073	22,922	34,017	41,783	47,219	51,024	53,688	55,553	56,858
Net income		57,032	65,258	73,787	82,635	91,819	101,356	111,266	31,042	132,286	143,441	146,248	158,351	170,969	184,131	197,870	212,217	227,209	242,883	259,281	276,445
FCF	$ (2,505,500)	389,307	393,255	397,206	401,156	405,099	409,029	412,939	326,294	420,668	(316,677)	432,995	436,682	440,296	443,823	447,251	450,567	453,756	456,801	459,684	462,388
NPV	$1,665,139																				
IRR	14%																				
Tax Calculations																					
Opening UCC		-	2,129,675	1,490,773	1,043,541	730,479	511,335	357,934	250,554	175,388	122,772	715,916	501,141	350,799	245,559	171,892	120,324	84,227	58,959	41,271	28,890
Capital Additions		2,505,500	-	-	-	-	-	-	-	-	741,149	-	-	-	-	-	-	-	-	-	-
CCA (Class 43.1)	30%	375,825	638,903	447,232	313,062	219,144	153,400	107,380	75,166	52,616	148,004	214,775	150,342	105,240	73,668	51,567	36,097	25,268	17,688	12,381	8,667
Taxable Income		(131,004)	(381,399)	(176,578)	(28,767)	79,311	159,759	221,058	269,157	308,230	230,041	181,178	264,271	328,828	380,694	423,975	461,566	495,510	527,257	557,845	588,022
Closing Tax Loss		(131,004)	(512,402)	(688,980)	(717,747)	(638,436)	(478,677)	(257,619)	-	-	-	-	-	-	-	-	-	-	-	-	-
Income Tax Payable		-	-	-	-	-	-	-	(94,582)	(108,312)	(80,836)	(63,666)	(92,865)	(115,550)	(133,776)	(148,985)	(162,194)	(174,122)	(185,278)	(196,027)	(206,631)
Tax Loss Carry Forward		(131,004)	(381,399)	(176,578)	(28,767)	79,311	159,759	221,058	257,619	-	-	-	-	-	-	-	-	-	-	-	-
Future Income Tax Considered		(30,899)	(35,356)	(39,976)	(44,770)	(49,746)	(54,913)	(60,282)	(61,810)	36,642	3,123	(15,568)	7,073	22,922	34,017	41,783	47,219	51,024	53,688	55,553	56,858
Energy Prices																					
Biomethane Sales Price ($CDN/GJ)	22.00	22.44	22.89	23.35	23.81	24.29	24.78	25.27	25.78	26.29	26.82	27.35	27.90	28.46	29.03	29.61	30.20	30.81	31.42	32.05	32.69
Biogas Purchase Price ($CDN/GJ)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Figure 25 - Financials for Case Study 3 with CNG - Biogas from AD of "Clean" Organics

Financial Analysis - Case Study 4 - Biogas Upgrading from WWTP for Grid Injection

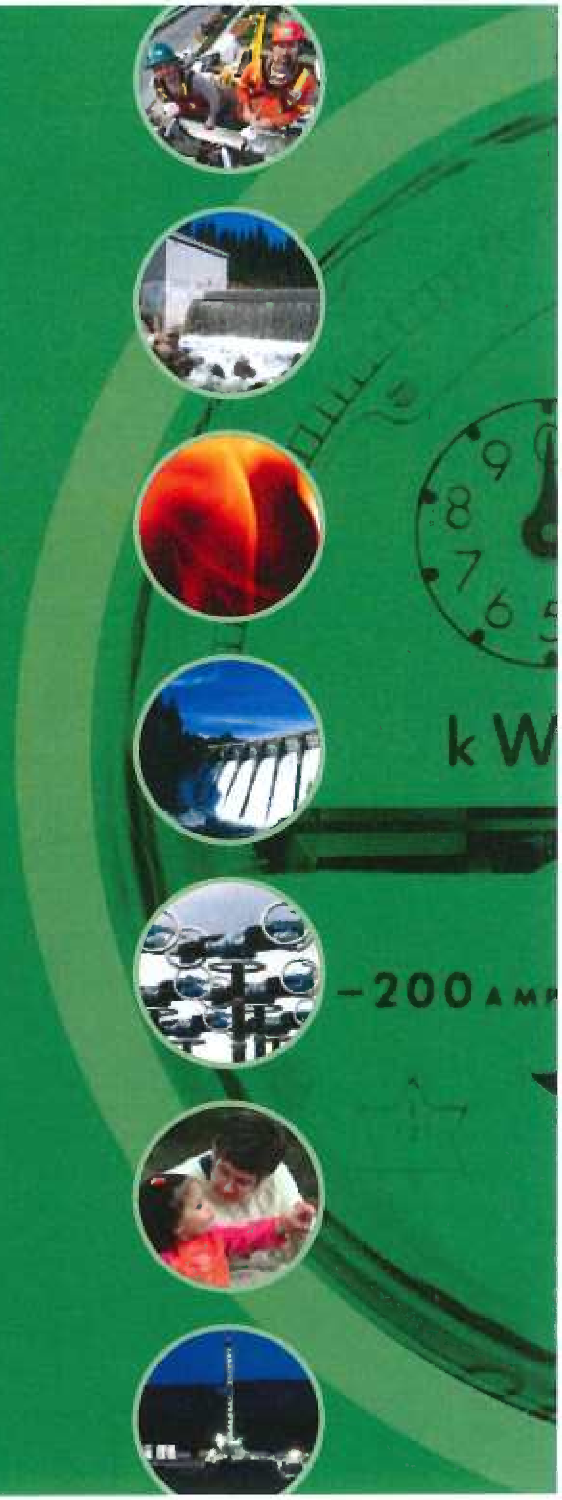
Year	0 2009	1 2010	2 2011	3 2012	4 2013	5 2014	6 2015	7 2016	8 2017	9 2018	10 2019
Inflation Factor	100.00%	102.00%	104.04%	106.12%	108.24%	110.41%	112.62%	114.87%	117.17%	119.51%	121.90%
Capital Investment	$ (4,170,500)										$ (736,273)
Operating Expenditure		$ (682,025)	$ (695,665)	$ (709,578)	$ (723,770)	$ (738,245)	$ (753,010)	$ (768,070)	$ (783,432)	$ (799,100)	$ (815,082)
Estimated Revenue		$ 2,729,093	$ 2,783,675	$ 2,839,349	$ 2,896,136	$ 2,954,058	$ 3,013,140	$ 3,073,402	$ 3,134,870	$ 3,197,568	$ 3,261,519
Depreciation		$ (239,933)	$ (239,933)	$ (239,933)	$ (239,933)	$ (239,933)	$ (239,933)	$ (239,933)	$ (239,933)	$ (239,933)	$ (239,933)
Incremental Overhead		$ (272,909)	$ (278,368)	$ (283,935)	$ (289,614)	$ (295,406)	$ (301,314)	$ (307,340)	$ (313,487)	$ (319,757)	$ (326,152)
Biogas Cost		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
EBIT		$ 1,534,226	$ 1,569,710	$ 1,605,902	$ 1,642,819	$ 1,680,474	$ 1,718,882	$ 1,758,059	$ 1,798,018	$ 1,838,778	$ 1,880,352
Interest		$ (291,935)	$ (284,814)	$ (277,194)	$ (269,041)	$ (260,318)	$ (250,983)	$ (240,995)	$ (230,308)	$ (218,873)	$ (206,638)
EBT		$ 1,242,291	$ 1,284,896	$ 1,328,708	$ 1,373,778	$ 1,420,157	$ 1,467,899	$ 1,517,063	$ 1,567,710	$ 1,619,904	$ 1,673,714
Income Tax Payable		$ (301,027)	$ (162,119)	$ (289,626)	$ (383,942)	$ (455,174)	$ (510,405)	$ (554,600)	$ (591,240)	$ (622,770)	$ (612,103)
Future Income Tax Considered		$ (135,515)	$ (289,394)	$ (177,282)	$ (98,803)	$ (43,869)	$ (5,414)	$ 21,504	$ 40,346	$ 53,536	$ 23,960
Net income		$ 805,750	$ 833,383	$ 861,800	$ 891,032	$ 921,114	$ 952,079	$ 983,967	$ 1,016,817	$ 1,050,670	$ 1,085,571
FCF	$ (4,170,500)	$ 1,337,618	$ 1,358,130	$ 1,378,927	$ 1,400,007	$ 1,421,364	$ 1,442,996	$ 1,464,896	$ 1,487,058	$ 1,509,476	$ 795,869
NPV	**$11,986,628**										
IRR	**33.14%**										
Tax Calculations											
Opening UCC		$ -	$ 3,544,925	$ 2,481,448	$ 1,737,013	$ 1,215,909	$ 851,136	$ 595,796	$ 417,057	$ 291,940	$ 204,358
Capital Additions		$ 4,170,500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 736,273
CCA (Class 43.1)	30%	$ 625,575	$ 1,063,478	$ 744,434	$ 521,104	$ 364,773	$ 255,341	$ 178,739	$ 125,117	$ 87,582	$ 171,748
Taxable Income		$ 856,649	$ 461,351	$ 824,207	$ 1,092,607	$ 1,295,317	$ 1,452,491	$ 1,578,258	$ 1,682,526	$ 1,772,255	$ 1,741,899
Closing Tax Loss		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Income Tax Payable		$ (301,027)	$ (162,119)	$ (289,626)	$ (383,942)	$ (455,174)	$ (510,405)	$ (554,600)	$ (591,240)	$ (622,770)	$ (612,103)
Tax Loss Carry Forward		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Future Income Tax Considered		$ (135,515)	$ (289,394)	$ (177,282)	$ (98,803)	$ (43,869)	$ (5,414)	$ 21,504	$ 40,346	$ 53,536	$ 23,960
Energy Prices											
Biomethane Sales Price ($CDN/GJ)	$ 8.00	$ 8.16	$ 8.32	$ 8.49	$ 8.66	$ 8.83	$ 9.01	$ 9.19	$ 9.37	$ 9.56	$ 9.75
Biogas Purchase Price ($CDN/GJ)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Year	11 2020	12 2021	13 2022	14 2023	15 2024	16 2025	17 2026	18 2027	19 2028	20 2029
Inflation Factor	124.34%	126.82%	129.36%	131.95%	134.59%	137.28%	140.02%	142.82%	145.68%	148.59%
Capital Investment										
Operating Expenditure	$ (831,384)	$ (848,012)	$ (864,972)	$ (882,271)	$ (899,917)	$ (917,915)	$ (936,274)	$ (954,999)	$ (974,099)	$ (993,581)
Estimated Revenue	$ 3,326,750	$ 3,393,285	$ 3,461,150	$ 3,530,373	$ 3,600,981	$ 3,673,000	$ 3,746,460	$ 3,821,389	$ 3,897,817	$ 3,975,774
Depreciation	$ (253,425)	$ (253,425)	$ (253,425)	$ (253,425)	$ (253,425)	$ (253,425)	$ (253,425)	$ (253,425)	$ (253,425)	$ (253,425)
Incremental Overhead	$ (332,675)	$ (339,328)	$ (346,115)	$ (353,037)	$ (360,098)	$ (367,300)	$ (374,646)	$ (382,139)	$ (389,782)	$ (397,577)
Biogas Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
EBIT	$ 1,909,266	$ 1,952,519	$ 1,996,638	$ 2,041,640	$ 2,087,541	$ 2,134,360	$ 2,182,116	$ 2,230,827	$ 2,280,512	$ 2,331,190
Interest	$ (193,546)	$ (179,538)	$ (164,549)	$ (148,510)	$ (131,350)	$ (112,987)	$ (93,340)	$ (72,317)	$ (49,823)	$ (25,754)
EBT	$ 1,715,720	$ 1,772,982	$ 1,832,090	$ 1,893,129	$ 1,956,191	$ 2,021,373	$ 2,088,776	$ 2,158,509	$ 2,230,689	$ 2,305,437
Income Tax Payable	$ (610,902)	$ (655,340)	$ (693,133)	$ (726,497)	$ (756,998)	$ (785,741)	$ (813,513)	$ (840,878)	$ (868,245)	$ (895,913)
Future Income Tax Considered	$ 7,998	$ 32,315	$ 49,336	$ 61,251	$ 69,592	$ 75,430	$ 79,517	$ 82,378	$ 84,381	$ 85,783
Net income	$ 1,112,816	$ 1,149,956	$ 1,188,293	$ 1,227,884	$ 1,268,786	$ 1,311,062	$ 1,354,780	$ 1,400,009	$ 1,446,825	$ 1,495,306
FCF	$ 1,559,787	$ 1,582,918	$ 1,606,267	$ 1,629,819	$ 1,653,560	$ 1,677,475	$ 1,701,545	$ 1,725,751	$ 1,750,072	$ 1,774,485
Tax Calculations										
Opening UCC	$ 768,882	$ 538,218	$ 376,752	$ 263,727	$ 184,609	$ 129,226	$ 90,458	$ 63,321	$ 44,325	$ 31,027
Capital Additions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA (Class 43.1)	$ 230,665	$ 161,465	$ 113,026	$ 79,118	$ 55,383	$ 38,768	$ 27,137	$ 18,996	$ 13,297	$ 9,308
Taxable Income	$ 1,738,480	$ 1,864,941	$ 1,972,489	$ 2,067,436	$ 2,154,233	$ 2,236,030	$ 2,315,063	$ 2,392,938	$ 2,470,816	$ 2,549,553
Closing Tax Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Income Tax Payable	$ (610,902)	$ (655,340)	$ (693,133)	$ (726,497)	$ (756,998)	$ (785,741)	$ (813,513)	$ (840,878)	$ (868,245)	$ (895,913)
Tax Loss Carry Forward	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Future Income Tax Considered	$ 7,998	$ 32,315	$ 49,336	$ 61,251	$ 69,592	$ 75,430	$ 79,517	$ 82,378	$ 84,381	$ 85,783
Energy Prices										
Biomethane Sales Price ($CDN/GJ)	$ 9.95	$ 10.15	$ 10.35	$ 10.56	$ 10.77	$ 10.98	$ 11.20	$ 11.43	$ 11.65	$ 11.89
Biogas Purchase Price ($CDN/GJ)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Figure 26 - Financials for Case Study 4 - Biogas from WWTP

The BC Energy Plan

A Vision for Clean Energy Leadership



BRITISH COLUMBIA
The Best Place on Earth

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MESSAGE FROM THE PREMIER

The BC Energy Plan: A Vision for Clean Energy Leadership is British Columbia's plan to make our province energy self-sufficient while taking responsibility for our natural environment and climate. The world has turned its attention to the critical issue of global warming. This plan sets ambitious targets. We will pursue them relentlessly as we build a brighter future for B.C.

The BC Energy Plan sets out a strategy for reducing our greenhouse gas emissions and commits to unprecedented investments in alternative technology based on the work that was undertaken by the Alternative Energy Task Force. Most importantly, this plan outlines the steps that all of us – including industry, environmental agencies, communities and citizens – must take to reach these goals for conservation, energy efficiency and clean energy so we can arrest the growth of greenhouse gases and reduce human impacts on the climate.

As stewards of this province, we have a responsibility to manage our natural resources in a way that ensures they both meet our needs today and the needs of our children and grandchildren. We will all have to think and act differently as we develop innovative and sustainable solutions to secure a clean and reliable energy supply for all British Columbians.

Our plan will make B.C. energy self-sufficient by 2016. To do this, we must maximize our conservation efforts. Conservation will reduce pressure on our energy supply and result in real savings for those who use less energy. Individual actions that reduce our own everyday energy consumption will make the difference between success and failure. For industry, conservation can lead to an effective, productive and significant competitive advantage. For communities, it can lead to healthier neighbourhoods and lifestyles for all of us.

We are looking at how we can use clean alternative energy sources, including bioenergy, geothermal, fuel cells, water-powered electricity, solar and wind to meet our province's energy needs. With each of these new options comes the opportunity for new job creation in areas such as research, development, and production of innovative energy and conservation solutions. The combination of renewable alternative energy sources and conservation will allow us to pursue our potential to become a net exporter of clean, renewable energy to our Pacific neighbours.

Just as the government's energy vision of 40 years ago led to massive benefits for our province, so will our decisions today. **The BC Energy Plan** will ensure a secure, reliable, and affordable energy supply for all British Columbians for years to come.

Premier Gordon Campbell

MESSAGE FROM THE MINISTER

The BC Energy Plan: A Vision for Clean Energy Leadership is a made-in-B.C. solution to the common global challenge of ensuring a secure, reliable supply of affordable energy in an environmentally responsible way. In the next decade government will balance the opportunities and increased prosperity available from our natural resources while leading the world in sustainable environmental management.

This energy plan puts us in a leadership role that will see the province move to eliminating or offsetting greenhouse gas emissions for all new projects in the growing electricity sector, end flaring from oil and gas producing wells, and put in place a plan to make B.C. electricity self-sufficient by 2016.

In developing this plan, the government met with key stakeholders, environmental non-government organizations, First Nations, industry representatives and others. In all, more than 100 meetings were held with a wide range of parties to gather ideas and feedback on new policy actions and strategies now contained in **The BC Energy Plan**.

By building on the strong successes of Energy Plan 2002, this energy plan will provide secure, affordable energy for British Columbia. Today, we reaffirm our commitment to public ownership of our BC Hydro assets while broadening our supply of available energy.

We look towards British Columbia's leading edge industries to help develop new, greener generation technologies with the support of the new **Innovative Clean Energy Fund**. We're planning for tomorrow, today. Our energy industry creates jobs for British Columbians, supports important services for our families, and will play an important role in the decade of economic growth and environmental sustainability that lies ahead.

The Ministry of Energy, Mines and Petroleum Resources is responding to challenges and opportunities by delivering innovative, sustainable ways to develop British Columbia's energy resources.

Honourable Richard Neufeld
Minister of Energy, Mines and Petroleum Resources

THE BC ENERGY PLAN HIGHLIGHTS

British Columbia's current electricity supply resources are 90 per cent clean and new electricity generation plants will have zero net greenhouse gas emissions.

In 2002, the Government of British Columbia launched an ambitious plan to invigorate the province's energy sector. Energy for Our Future: A Plan for BC was built around four cornerstones: low electricity rates and public ownership of BC Hydro; secure, reliable supply; more private sector opportunities; and environmental responsibility with no nuclear power sources. Today, our challenges include a growing energy demand, higher prices, climate change and the need for environmental sustainability. **The BC Energy Plan: A Vision for Clean Energy Leadership** builds on the successes of the government's 2002 plan and moves forward with new policies to meet the challenges and opportunities ahead.

Environmental Leadership

The BC Energy Plan puts British Columbia at the forefront of environmental and economic leadership by focusing on our key natural strengths and our competitive advantages of clean and renewable sources of energy. The plan further strengthens our environmental leadership through the following key policy actions:

- **Zero greenhouse gas emissions from coal fired electricity generation.**
- **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.**
- **No nuclear power.**
- **Best coalbed gas practices in North America.**
- **Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.**

A Strong Commitment to Energy Conservation and Efficiency

Conservation is integral to meeting British Columbia's future energy needs. **The BC Energy Plan** sets ambitious conservation targets to reduce the growth in electricity used within the province. British Columbia will:

- **Set an ambitious target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.**
- **Implement energy efficient building standards by 2010.**

Current per household electricity consumption for BC Hydro customers is about 10,000 Kwh per year. Achieving this conservation target will see electricity use per household decline to approximately 9,000 Kwh per year by 2020.

Energy Security

The Government of British Columbia is taking action to ensure that the energy needs of British Columbians continue to be met now and into the future. As part of ensuring our energy security, **The BC Energy Plan** sets the following key policy actions:

- **Maintain public ownership of BC Hydro and the BC Transmission Corporation.**
- **Maintain our competitive electricity rate advantage.**
- **Achieve electricity self-sufficiency by 2016.**
- **Make small power part of the solution through a set purchase price for electricity generated from projects up to 10 megawatts.**
- **Explore value-added opportunities in the oil and gas industry by examining the viability of a new petroleum refinery and petrochemical industry.**
- **Be among the most competitive oil and gas jurisdictions in North America.**
- **BC Hydro and the Province will enter into initial discussions with First Nations, the Province of Alberta and communities to discuss Site C to ensure that communications regarding the potential project and the processes being followed are well known.**

Investing in Innovation

British Columbia has a proven track record in bringing ideas and innovation to the energy sector. From our leadership and experience in harnessing our hydro resources to produce electricity, to our groundbreaking work in hydrogen and fuel cell technology, British Columbia has always met its future energy challenges by developing new, improved and sustainable solutions. To support future innovation and to help bridge the gap experienced in bringing innovations through the pre-commercial stage to market, government will:

- **Establish an Innovative Clean Energy Fund of $25 million.**
- **Implement the BC Bioenergy Strategy to take full advantage of B.C.'s abundant sources of renewable energy.**
- **Generate electricity from mountain pine beetle wood by turning wood waste into energy.**

POLICY ACTIONS

COMMITMENT TO CONSERVATION

- **Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.**
- **Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.**
- **Encourage utilities to pursue cost effective and competitive demand side management opportunities.**
- **Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.**

Ambitious Energy Conservation and Efficiency Targets

The more energy that is conserved, the fewer new sources of supply we will require in the future. That is why British Columbia is setting new conservation targets to reduce growth in electricity demand.

Inefficient use of energy leads to higher costs and many environmental and security of supply problems.

Conservation Target

The BC Energy Plan sets an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020. This will require building on the "culture of conservation" that British Columbians have embraced in recent years.

The plan confirms action on the part of government to complement these conservation targets by working closely with BC Hydro and other utilities to research, develop, and implement best practices in conservation and energy efficiency and to increase public awareness. In addition, the plan supports utilities in British Columbia and the BC Utilities Commission pursuing all cost effective and competitive demand side management programs. Utilities are also encouraged to explore and develop rate designs to encourage efficiency, conservation and the development of renewable energy.

Future energy efficiency and conservation initiatives will include:

- Continuing to remove barriers that prevent customers from reducing their consumption.
- Building upon efforts to educate customers about the choices they can make today with respect to the amount of electricity they consume.
- Exploring new rate structures to identify opportunities to use rates as a mechanism to motivate customers either to use less electricity or use less at specific times.
- Employing new rate structures to help customers implement new energy efficient products and technologies and provide them with useful information about their electricity consumption to allow them to make informed choices.
- Advancing ongoing efforts to develop energy-efficient products and practices through regulations, codes and standards.

The average household uses about 10,000 kilowatt-hours of electricity per year.

Implement Energy Efficiency Standards for Buildings by 2010

British Columbia implemented *Energy Efficient Buildings: A Plan for BC* in 2005 to address specific barriers to energy efficiency in our building stock through a number of voluntary policy and market measures. This plan has seen a variety of successes including smart metering pilot projects, energy performance measurement and labelling, and increased use of Energy Star appliances. In 2005, B.C. received a two year, $11 million federal contribution from the Climate Change Opportunities Envelope to support implementation of this plan.

Working together industry, local governments, other stakeholders and the provincial government will determine and implement cost effective energy efficiency standards for new buildings by 2010. Regulated standards for buildings are a central component of energy efficiency programs in leading jurisdictions throughout the world.

The BC Energy Plan supports reducing consumption by raising awareness and enhancing the efforts of utilities, local governments and building industry partners in British Columbia toward conservation and energy efficiency.

Aggressive Public Sector Building Plan

The design and retrofit of buildings and their surrounding landscapes offer us an important means to achieve our goal of making the government of British Columbia carbon neutral by 2010, and promoting Pacific Green universities, colleges, hospitals, schools, prisons, ferries, ports and airports.

British Columbia communities are already recognized leaders in innovative design practices. We know how to build smarter, faster and smaller. We know how to increase densities, reduce building costs and create new positive benefits for our environment. We know how to improve air quality, reduce energy consumption and make wise use of other resources, and how to make our landscapes and buildings healthy places for living, working and learning. We know how to make it affordable.

Government will set the following ambitious goals for all publicly funded buildings and landscapes and ask the Climate Action Team to determine the most credible, aggressive and economically viable options for achieving them:

- Require integrated environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.
- Supply green, healthy workspaces for all public service employees.
- Capture the productivity benefits for people who live and work in publicly funded buildings such as reduced illnesses, less absenteeism, and a better learning environment.
- Aim not only for the lowest impact, but also for restoration of the ecological features of the surrounding landscapes.

Gigawatt = 1,000,000 kilowatts
Kilowatt = amount of power to light ten 100-watt incandescent light bulbs.

Community Action on Energy Efficiency

British Columbia is working in partnership with local governments to encourage energy conservation at the community level through the Community Action on Energy Efficiency Program. The program promotes energy efficiency and community energy planning projects, providing direct policy and technical support to local governments through a partnership with the Fraser Basin Council. A total of 29 communities are participating in the program and this plan calls for an increase in the level of participation and expansion of the program to include transportation actions. The Community Action on Energy Efficiency Program is a collaboration among the provincial ministries of Energy, Mines and Petroleum Resources, Environment, and Community Services, Natural Resources Canada, the Fraser Basin Council, Community Energy Association, BC Hydro, FortisBC, Terasen Gas, and the Union of BC Municipalities.

Leading the Way to a Future with Green Buildings and Green Cities

British Columbia has taken a leadership role in the development of green buildings. Through the Green Buildings BC Program, the province is working to reduce the environmental impact of government buildings by increasing energy and water efficiency and reducing greenhouse gas emissions. Through this program, and the Energy Efficient Buildings Strategy that establishes energy efficiency targets for all types of buildings, the province is inviting businesses, local governments and all British Columbians to do their part to increase energy efficiency and reduce greenhouse gas emissions.

The Green Cities Project sets a number of strategies to make our communities greener, healthier and more vibrant places to live. British Columbia communities are already recognized leaders in innovative sustainability practices, and the Green Cities Project will provide them with additional resources to improve air quality, reduce energy consumption and encourage British Columbians to get out and enjoy the outdoors. With the Green Cities Project, the provincial government will:

- Provide $10 million a year over four years for the new LocalMotion Fund, which will cost share capital projects on a 50/50 basis with municipal governments to build bike paths, walkways, greenways and improve accessibility for people with disabilities.
- Establish a new Green City Awards program to encourage the development and exchange of best practices by communities, with the awards presented annually at the Union of British Columbia Municipalities convention.
- Set new financial incentives to help local governments shift to hybrid vehicle fleets and help retrofit diesel vehicles.
- Commit to making new investments in expanded rapid transit, support for fuel cell vehicles and other innovations.

Industrial Energy Efficiency Program

Government will establish an Industrial Energy Efficiency Program for British Columbia to address challenges and issues faced by the B.C. industrial sector and support the Canada wide industrial energy efficiency initiatives. The program will encourage industry driven investments in energy efficient technologies and processes; reduce emissions and greenhouse gases; promote self generation of power; and reduce funding barriers that discourage energy efficiency in the industrial sector. Some specific strategies include developing a results based pilot program with industry to improve energy efficiency and reduce overall power consumption and promote the generation of renewable energy within the industrial sector.

The 2010 Olympic and Paralympics Games: Sustainability in Action

In 2010 Vancouver and Whistler will host the Winter Olympic and Paralympic Games. The 2010 Olympic Games are the first that have been organized based on the principles of sustainability.

All new buildings for the Olympics will be designed and built to conserve both water and materials, minimize waste, maximize air quality, protect surrounding areas and continue to provide environmental and community benefits over their lifetimes. Existing venues will be upgraded to showcase energy conservation and efficiency and demonstrate the use of alternative heating/cooling technologies. Wherever possible, renewable energy sources such as wind, solar, micro hydro, and geothermal energy will be used to power and heat all Games facilities.

Transportation for the 2010 Games will be based on public transit. This system – which will tie event tickets to transit use – will help reduce traffic congestion, minimize local air pollution and limit greenhouse gas emissions.

POLICY ACTIONS

BUILDING STANDARDS, COMMUNITY ACTION AND INDUSTRIAL EFFICIENCY

- **Implement Energy Efficiency Standards for Buildings by 2010.**
- **Undertake a pilot project for energy performance labelling of homes and buildings in coordination with local and federal governments, First Nations and industry associations.**
- **New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.**
- **Develop an Industrial Energy Efficiency Program for British Columbia to address specific challenges faced by British Columbia's industrial sector.**
- **Increase the participation of local governments in the Community Action on Energy Efficiency Program and expand the First Nations and Remote Community Clean Energy Program.**

British Columbia benefits from the public ownership of BC Hydro and the BC Transmission Corporation.

POLICY ACTIONS

SELF-SUFFICIENCY BY 2016

- **Ensure self-sufficiency to meet electricity needs, including "insurance."**
- **Establish a standing offer for clean electricity projects up to 10 megawatts.**
- **The BC Transmission Corporation is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.**
- **Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy.**
- **Ensure that the province remains consistent with North American transmission reliability standards.**

Electricity Security

Electricity, while often taken for granted, is the lifeblood of our modern economy and key to our entire way of life. Fortunately, British Columbia has been blessed with an abundant supply of clean, affordable and renewable electricity. But today, as British Columbia's population has grown, so too has our demand for electricity. We are now dependent on other jurisdictions for up to 10 per cent of our electricity supply. BC Hydro estimates demand for electricity to grow by up to 45 per cent over the next 20 years.

We must address this ever increasing demand to maintain our secure supply of electricity and the competitive advantage in electricity rates that all British Columbians have enjoyed for the last 20 years. There are no simple solutions or answers. We have an obligation to future generations to chart a course that will ensure a secure, environmentally and socially responsible electricity supply.

To close this electricity gap, and for our province to become electricity self-sufficient, will require an innovative electricity industry and the real commitment of all British Columbians to conservation and energy efficiency.

The New Relationship and Electricity

The Government of British Columbia is working with First Nations to restore, revitalize and strengthen First Nations communities. The goal is to build strong and healthy relationships with First Nations people guided by the principles of trust and collaboration. First Nations share many of the concerns of other British Columbians in how the development of energy resources may impact as well as benefit their communities. In addition, First Nations have concerns with regard to the recognition and respect of Aboriginal rights and title.

By focusing on building partnerships between First Nations, industry and government, tangible social and economic benefits will flow to First Nations communities across the province and assist in eliminating the gap between First Nations people and other British Columbians.

Government is working every day to ensure that energy resource management includes First Nations' interests, knowledge and values. By continuing to engage First Nations in energy related issues, we have the opportunity to share information and look for opportunities to facilitate First Nations' employment and participation in the electricity sectors to ensure that First Nations people benefit from the continued growth and development of British Columbia's resources. **The BC Energy Plan** provides British Columbia with a blueprint for facing the many energy challenges and opportunities that lay ahead. It provides an opportunity to build on First Nations success stories such as:

- First Nations involvement in independent power projects, such as the Squamish First Nation's participation in the Furry Creek and Ashlu hydro projects.

- Almost $4 million will flow to approximately 10 First Nations communities across British Columbia to support the implementation of Community Energy Action Plans as part of the First Nation and Remote Community Clean Energy Program.
- The China Creek independent power project was developed by the Hupacasath First Nation on Vancouver Island.

Achieve Electricity Self-Sufficiency by 2016

Achieving electricity self-sufficiency is fundamental to our future energy security and will allow our province to achieve a reliable, clean and affordable supply of electricity. It also represents a lasting legacy for future generations of British Columbians. That's why government has committed that British Columbia will be electricity self-sufficient within the decade ahead.

Through **The BC Energy Plan**, government will set policies to guide BC Hydro in producing and acquiring enough electricity in advance of future need. However, electricity generation and transmission infrastructure require long lead times. This means that over the next two decades, BC Hydro must acquire an additional supply of "insurance power" beyond the projected increases in demand to minimize the risk and implications of having to rely on electricity imports.

Small Power Standing Offer

Achieving electricity self-sufficiency in British Columbia will require a range of new power sources to be brought on line. To help make this happen, this policy will direct BC Hydro to establish a Standing Offer Program with no quota to encourage small and clean electricity producers. Under the Standing Offer Program, BC Hydro will purchase directly from suppliers at a set price.

Eligible projects must be less than 10 megawatts in size and be clean electricity or high efficiency electricity cogeneration. The price offered in the standing offer contract would be based on the prices paid in the most recent BC Hydro energy call. This will provide small electricity suppliers with more certainty, bring small power projects into the system more quickly, and help achieve government's goal of maintaining a secure electricity supply. As well, BC Hydro will offer the same price to those in BC Hydro's Net Metering Program who have a surplus of generation at the end of the year.

Ensuring a Reliable Transmission Network

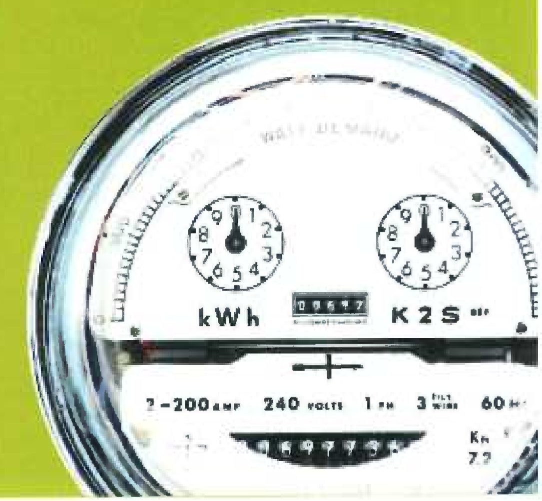
An important part of meeting the goal of self-sufficiency is ensuring a reliable transmission infrastructure is in place as additional power is brought on line. Transmission is a critical part of the solution as often new clean sources of electricity are located away from where the demand is. In addition, transmission investment is required to support economic growth in the province and must be planned and started in anticipation of future electricity needs given the long lead times required for transmission development. New and upgraded transmission infrastructure will be required to avoid congestion and to efficiently move the electricity across the entire power grid. Because our transmission system is part of a much larger, interconnected grid, we need to work with other jurisdictions to maximize the benefit of interconnection, remain consistent with evolving North American reliability standards, and ensure British Columbia's infrastructure remains capable of meeting customer needs.

BC HYDRO'S NET METERING PROGRAM: PEOPLE PRODUCING POWER

BC Hydro's Net Metering Program was established as a result of Energy Plan 2002. It is designed for customers with small generating facilities, who may sometimes generate more electricity than they require for their own use. A net metering customer's electricity meter will run backwards when they produce more electricity than they consume and run forward when they produce less than they consume.

The customer is only billed for their "net consumption"; the total amount of electricity used minus the total produced.

Net metering allows customers to lower their environmental impact and take responsibility for their own power production. It helps to move the province towards electricity self-sufficiency and expands clean electricity generation, making B.C.'s electricity supply more environmentally sustainable.



In order for British Columbia to ensure the development of a secure and reliable supply of electricity, **The BC Energy Plan** provides policy direction to the BC Transmission Corporation to ensure that our transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand. This will include ensuring there is adequate transmission capacity, ongoing investments in technology and infrastructure and remaining consistent with evolving North American reliability standards.

BC Transmission Corporation Innovation and Technology

As the manager of a complex and high-value transmission grid, BC Transmission Corporation is introducing technology innovations that provide improvements to the performance of the system and allow for a greater utilization of existing assets, ensuring B.C. continues to benefit from one of the most advanced energy networks in the world. BC Transmission Corporation's innovation program focuses on increasing the power transfer capability of existing assets, extending the life of assets and improving system reliability and security. Initiatives include:

- System Control Centre Modernization Project: This project is consolidating system operations into a new control center and backup site and upgrading operating technologies with a modern management system that includes enhancements to existing applications to ensure the electric grid is operating reliably and efficiently. The backup site will take over complete operation of the electric grid if the main site is unavailable.
- Real-Time Phasors: British Columbia is among the first North American jurisdictions to incorporate phasor measurement into control centre operations. Phasors are highly accurate voltage, current and phase angle "snapshots" of the real-time state of the transmission system that enable system operators to monitor system conditions and identify any impending problems.
- Real-Time Rating: This is a temperature monitoring system which enables the operation of two 500 kilovolt submarine cable circuits at maximum capacity without overloading. The resulting increase in capacity is estimated to be up to 10 per cent, saving millions of dollars.
- Electronic Temperature Monitor Upgrades for Station Transformers: In this program, existing mechanical temperature monitors will be replaced with newer, more accurate electronic monitors on station transformers that allow transformers to operate to maximum capacity without overheating. In addition to improving performance, BC Transmission Corporation will realize reduced maintenance costs as the monitors are "self-checking."
- Life Extension of Transmission Towers: BC Transmission Corporation maintains over 22,000 steel lattice towers and is applying a special composite corrosion protection coating to some existing steel towers to extend their life by about 25 years.

Public Ownership

Public Ownership of BC Hydro and the BC Transmission Corporation

BC Hydro and the BC Transmission Corporation are publicly-owned crown corporations and will remain that way now and into the future. BC Hydro is responsible for generating, purchasing and distributing electricity. The BC Transmission Corporation operates, maintains, and plans BC Hydro's transmission assets and is responsible for providing fair, open access to the power grid for all customers. Both crowns are subject to the review and approvals of the independent regulator, the BC Utilities Commission.

BC Hydro owns the heritage assets, which include historic electricity facilities such as those on the Peace and Columbia Rivers that provide a secure, reliable supply of low-cost power for British Columbians. These heritage assets require maintenance and upgrades over time to ensure they continue to operate reliably and efficiently. Potential improvements to these assets, such as capacity additions at the Mica and Revelstoke generating stations, can make important contributions for the benefit of British Columbians.

Confirming the Heritage Contract in Perpetuity

Under the 2002 Energy Plan, a legislated heritage contract was established for an initial term of 10 years to ensure BC Hydro customers benefit from its existing low-cost resources. With **The BC Energy Plan**, government confirms the heritage contract in perpetuity to ensure ratepayers will continue to receive the benefits of this low-cost electricity for generations to come.

British Columbia's Leadership in Clean Energy

The BC Energy Plan will continue to ensure British Columbia has an environmentally and socially responsible electricity supply with a focus on conservation and energy efficiency.

British Columbia is already a world leader in the use of clean and renewable electricity, due in part to the foresight of previous generations who built our province's hydroelectric dams. These dams - now British Columbians' 'heritage assets' - today help us to enjoy 90 per cent clean electricity, one of the highest levels in North America.

All New Electricity Generation Projects Will Have Zero Net Greenhouse Gas Emissions

The B.C. government is a leader in North America when it comes to environmental standards. While British Columbia is a province rich in energy resources such as hydro electricity, natural gas and coal, the use of these resources needs to be balanced through effective use, preserving our environmental standards, while upholding our quality of life for generations to come. The government has made a commitment that all new electricity generation projects developed in British Columbia and connected to the grid will have zero net greenhouse gas emissions. In addition, any new electricity generated from coal must meet the more stringent standard of zero greenhouse gas emissions.

POLICY ACTIONS

PUBLIC OWNERSHIP

- **Continue public ownership of BC Hydro and its heritage assets, and the BC Transmission Corporation.**
- **Establish the existing heritage contract in perpetuity.**
- **Invest in upgrading and maintaining the heritage asset power plants and the transmission lines to retain the ongoing competitive advantage these assets provide to the province.**

POLICY ACTIONS

REDUCING GREENHOUSE GAS EMISSIONS FROM ELECTRICITY

- **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.**
- **Require zero greenhouse gas emissions from any coal thermal electricity facilities.**
- **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.**
- **No nuclear power.**

Zero Net Greenhouse Gas Emissions from Existing Thermal Generation Power Plants by 2016

Setting a requirement for zero net emissions over this time period encourages power producers to invest in new or upgraded technology. For existing plants the government will set policy around reaching zero net emissions through carbon offsets from other activities in British Columbia. It clearly signals the government's intention to continue to have one of the lowest greenhouse gas emission electricity sectors in the world.

Ensure Clean or Renewable Electricity Generation Continues to Account For at Least 90 per cent of Total Generation

Currently in B.C., 90 per cent of electricity is from clean or renewable resources. **The BC Energy Plan** commits to maintaining this high standard which places us among the top jurisdictions in the world. Clean or renewable resources include sources of energy that are constantly renewed by natural processes, such as water power, solar energy, wind energy, tidal energy, geothermal energy, wood residue energy, and energy from organic municipal waste.

Zero Greenhouse Gas Emissions from Coal

The government is committed to ensuring that British Columbia's electricity sector remains one of the cleanest in the world and will allow coal as a resource for electricity generation when it can reach zero greenhouse gas emissions. Clean-coal technology with carbon sequestration is expected to become commercially available in the next decade. Therefore, the province will require zero greenhouse gas emissions from any coal thermal electricity facilities which can be met through capture and sequestration technology. British Columbia is the first Canadian jurisdiction to commit to using only clean coal technology for any electricity generated from coal.

Burrard Thermal Generating Station

A decision regarding the Burrard Thermal Natural Gas Generating Station is another action that is related to environmentally responsible electricity generation in British Columbia.

Even though it could generate electricity from Burrard Thermal, BC Hydro imports power primarily because the plant is outdated, inefficient and costly to run. However, Burrard Thermal still provides significant benefits to BC Hydro as it acts as a "battery" close to the Lower Mainland, and provides extra capacity or "reliability insurance" for the province's electricity supply. It also provides transmission system benefits that would otherwise have to be supplied through the addition of new equipment at Lower Mainland sub-stations.

By 2014, BC Hydro plans to have firm electricity to replace what would have been produced at the plant. Government supports BC Hydro's proposal to replace the firm energy supply from Burrard Thermal with other resources by 2014. However, BC Hydro may choose to retain the plant for "reliability insurance" should the need arise.

No Nuclear Power

As first outlined in Energy Plan 2002, government will not allow production of nuclear power in British Columbia.

Benefits to British Columbians

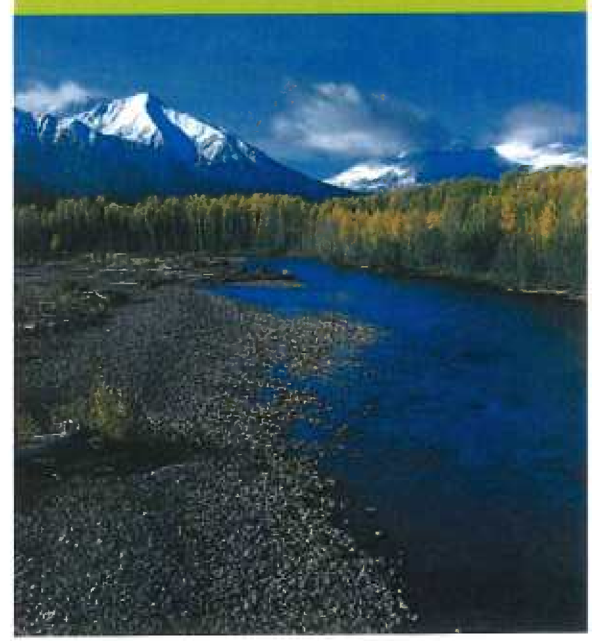
Clean or renewable electricity comes from sources that replenish over a reasonable time or have minimal environmental impacts. Today, demand for economically viable, clean, renewable and alternative energy is growing along with the world's population and economies. Consumers are looking for power that is not only affordable but creates minimal environmental impacts. Fortunately, British Columbia has abundant hydroelectric resources, and plenty of other potential energy sources.

Maintain our Electricity Competitive Advantage

British Columbians require a secure, reliable supply of competitively priced electricity now and in the future. Competitively priced power is also an incentive for investors to locate in British Columbia. It provides an advantage over other jurisdictions and helps sustain economic growth. We are fortunate that historic investments in hydroelectric assets provide electricity that is readily available, reliable, clean and inexpensive. By ensuring public ownership of BC Hydro, the heritage assets and the BC Transmission Corporation and confirming the heritage contract in perpetuity, we will ensure that ratepayers continue to receive the benefits of this low cost generation. Due to load growth and aging infrastructure, new investments will be required. Investments in maintenance and in some cases expansions can be a cost effective way to meet growth and reduce future rate increases.

CARBON OFFSETS AND HOW THEY REDUCE EMISSIONS

A carbon offset is an action taken directly, outside of normal operations, which results in reduced greenhouse gas emissions or removal of greenhouse gases from the atmosphere. Here's how it works: if a project adds greenhouse gases to the atmosphere, it can effectively subtract them by purchasing carbon offsets which are reductions from another activity. Government regulations to reduce greenhouse gases, including offsets, demonstrate leadership on climate change and support a move to clean and renewable energy.



ELECTRICITY

*Government will establish a $25 million **Innovative Clean Energy Fund.***

POLICY ACTIONS

BENEFITS TO BRITISH COLUMBIANS

- **Review BC Utilities Commissions' role in considering social and environmental costs and benefits.**
- **Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources.**
- **Work with BC Hydro and parties involved to continue to improve the procurement process for electricity.**
- **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.**

British Columbia must look for new, innovative ways to stay competitive. New technologies must be identified and nurtured, from both new and existing industries. By diversifying and strengthening our energy sector through the development of new and alternative energy sources, we can help ensure the province's economy remains vibrant for years to come.

Ensure Electricity is Secured at Competitive Prices

One practical way to keep rates down is to ensure utilities have effective processes for securing competitively priced power. As part of **The BC Energy Plan**, government will work with BC Hydro and parties involved to continue to improve the Call for Tender process for acquiring new generation. Fair treatment of both buyers and sellers of electricity will facilitate a robust and competitive procurement process. Government and BC Hydro will also look for ways to further recognize the value of intermittent resources, such as run-of- river and wind, in the acquisition process – which means that BC Hydro will examine ways to value separate projects together to increase the amount of firm energy calculated from the resources.

Rates Kept Low Through Powerex Trading of Electricity

Profits from electricity trade also contribute to keeping our electricity rates competitive. BC Hydro, through its subsidiary, Powerex, buys and sells electricity when it is advantageous to British Columbia's ratepayers. Government will continue to support capitalizing on electricity trading opportunities and will continue to allocate trade revenue to BC Hydro ratepayers to keep electricity rates low for all British Columbians.

BC Utilities Commissions' Role in Social and Environmental Costs and Benefits

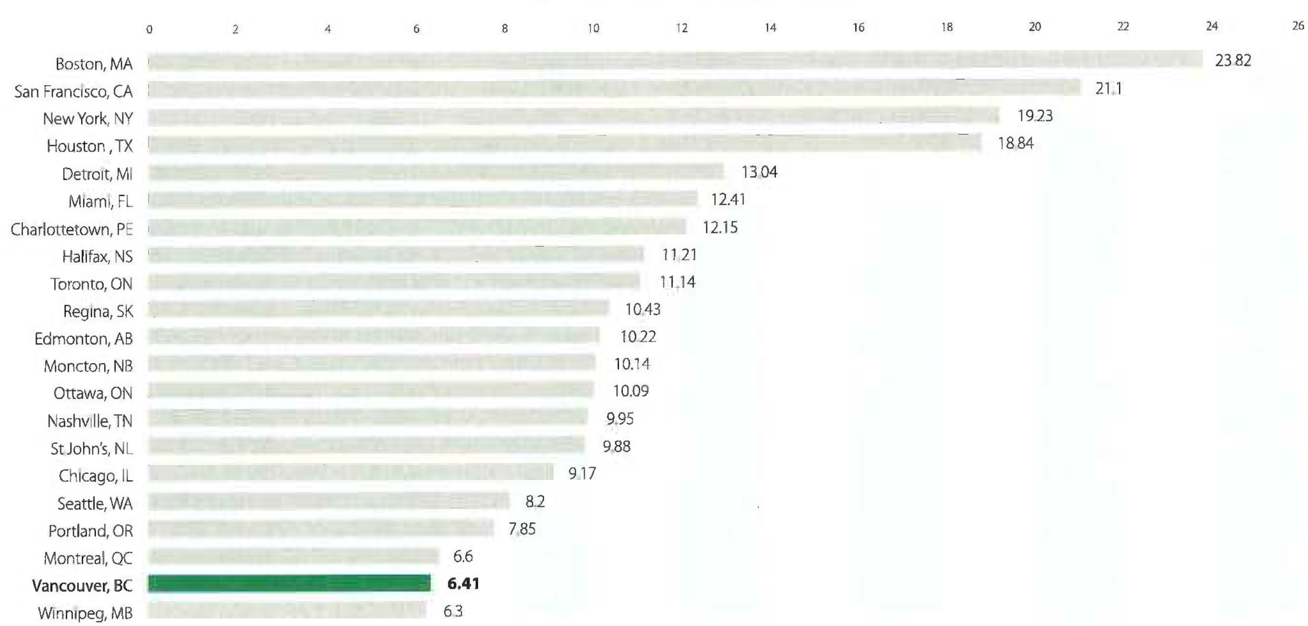
The BC Energy Plan clarifies that social, economic and environmental costs are important for ensuring a suitable electricity supply in British Columbia. Government will review the BC Utilities Commissions' role in considering social, environmental and economic costs and benefits, and will determine how best to ensure these are appropriately considered within the regulatory framework.

Bring Clean Power to Communities

British Columbia's electricity industry supports thousands of well-paying jobs, helps drive the economy and provides revenues to sustain public services. British Columbia's electricity industry already fosters economic development by implementing cost effective and reliable energy solutions in communities around the province. However, British Columbia covers almost one million square kilometres and electrification does not extend to all parts of our vast province.

Government and BC Hydro have established First Nation and remote community energy programs to implement alternative energy, energy efficiency, conservation and skills training solutions in a number of communities. The program focuses on expanding electrification services to as many as 50 remote and First Nations communities in British Columbia, enabling them to share in the benefits of a stable and secure supply of electricity. Government will put the policy framework in place and BC Hydro will implement the program over the next 10 years. The **Innovative Clean Energy Fund** can also support technological advancements to address the issue of providing a clean and secure supply of electricity to remote communities.

2006 Average Residential Electricity Price



Source: Hydro Quebec comparison of Electricity Prices in Major North American Cities, April 2006

BRINGING CLEAN POWER TO ATLIN

Electricity in the remote community of Atlin in northwestern British Columbia is currently supplied by diesel generators. The First Nations and Remote Community Clean Energy Program is bringing clean power to Atlin.

The Taku Land Corporation, solely owned by the Taku River Tlingit First Nation will construct a two megawatt run-of-river hydroelectric project on Pine Creek, generating local economic benefits and providing clean power for Atlin. The Taku Land Corporation has entered into a 25 year Electricity Purchase Agreement with BC Hydro to supply electricity from the project to Atlin's grid. Over the course of the agreement, this will reduce greenhouse gas emissions by up to 150,000 tonnes as the town's diesel generators stand by.

The province is contributing $1.4 million to this $10 million project. This is the first payment from a $3.9 million federal contribution to British Columbia's First Nations and Remote Community Clean Energy Program. Criteria for federal funding included demonstrating greenhouse gas emissions reductions, cost-effectiveness, and partnerships with communities and industry.

Government will work with other agencies to maximize opportunities to develop, deploy and export British Columbia clean and alternative energy technologies.

POLICY ACTIONS

INVESTING IN INNOVATION

- **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.**

Innovative Clean Energy Fund

British Columbia's increasing energy requirements and our ambitious greenhouse gas emission reduction and clean energy targets require greater investment and innovation in the area of alternative energy by both the public and private sector.

To lead this effort, the government will establish an **Innovative Clean Energy Fund** of $25 million to help promising clean power technology projects succeed. The fund will be established through a small charge on energy utilities. The Minister of Energy, Mines and Petroleum Resources will consult with the energy utilities on the implementation of this charge.

Proponents of projects that will be supported through the fund will be encouraged to seek additional contributions from other sources. Government's new **Innovative Clean Energy Fund** will help make British Columbia a world leader in alternative energy and power technology. It will solve some of B.C.'s pressing energy challenges, protect our environment, help grow the economy, position the province as the place international customers turn to for key energy and environmental solutions, and assist B.C. based companies to showcase their products to world wide markets.

Following the advice of the Premier's Technology Council and the Alternative Energy and Power Technology Task Force, the fund will focus strictly on projects that:

- Address specific British Columbia energy and environmental problems that have been identified by government.
- Showcase B.C. technologies that have a strong potential for international market demand in other jurisdictions because they solve problems that exist both in B.C. and other jurisdictions.
- Support pre-commercial energy technology that is new, or commercial technologies not currently used in British Columbia.
- Demonstrate commercial success for new energy technologies.

Some problems that the fund could focus on include:

- Developing reliable power solutions for remote communities-particularly helping First Nations communities reduce their reliance on diesel generation for electricity.
- Advance conservation technologies to commercial application.
- Finding ways to convert vehicles to cleaner alternative fuels.
- Increasing the efficiency of power transmission through future grid technologies.
- Expanding the opportunities to generate power using alternative fuels (e.g.mountain pine beetle wood).

The British Columbia Bioenergy Strategy: Growing Our Natural Energy Advantage

Currently, British Columbia is leading Canada in the use of biomass for energy. The province has 50 per cent of Canada's biomass electricity generating capacity. In 2005, British Columbia's forest industry self-generated the equivalent of $150 million in electricity and roughly $1.5 billion in the form of heat energy. The use of biomass has displaced some natural gas consumption in the pulp and paper sector. The British Columbia wood pellet industry also enjoys a one-sixth share of the growing European Union market for bioenergy feedstock. The province will shortly release a bioenergy strategy that will build upon British Columbia's natural bioenergy resource advantages, industry capabilities and academic strength to establish British Columbia as a world leader in bioenergy development.

British Columbia's plan is to lead the bioeconomy in Western Canada with a strong and sustainable bioenergy sector. This vision is built on two guiding principles:

- Competitive, diversified forest and agriculture sectors.
- Strengthening regions and communities.

The provincial Bioenergy Strategy is aimed at:

- Enhancing British Columbia's ability to become electricity self-sufficient.
- Fostering the development of a sustainable bioenergy sector.
- Creating new jobs.
- Supporting improvements in air quality.
- Promoting opportunities to create power from mountain pine beetle-impacted timber.
- Positioning British Columbia for world leadership in the development and commercial adoption of wood energy technology.
- Advancing innovative solutions to agricultural and other waste management challenges.
- Encouraging diversification in the forestry and agriculture industries.
- Producing liquid biofuels to meet Renewable Fuel Standards and displace conventional fossil fuels.

Generating Electricity from Mountain Pine Beetle Wood: Turning Wood Waste into Energy

British Columbia is experiencing an unprecedented mountain pine beetle infestation that has affected several million hectares of trees throughout the province. This infestation is having a significant impact on forestry-based communities and industries, and heightens forest fire risk. There is a great opportunity to convert the affected timber to bioenergy, such as wood pellets and wood-fired electricity generation and cogeneration.

Through **The BC Energy Plan**, BC Hydro will issue 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.

MOUNTAIN PINE BEETLE INFESTATION: TURNING WOOD WASTE INTO ENERGY

British Columbia is experiencing an unprecedented mountain pine beetle infestation that has affected several million hectares of trees throughout the province. This infestation is having a significant economic impact on B.C.'s forestry industry and the many communities it helps to support and sustain. The forest fire risk to these communities has also risen as a result of their proximity to large stands of "beetle-killed" wood.

B.C. has developed a bioenergy strategy to promote new sources of sustainable and renewable energy in order to take advantage of the vast amounts of pine beetle-infested timber and other biomass resources. In the future, bioenergy will help meet our electricity needs, supplement conventional natural gas and petroleum supplies, maximize job and economic opportunities, and protect our health and environment.

The production of wood pellets is already a mature industry in British Columbia. Industry has produced over 500,000 tonnes of pellets and exported about 90 per cent of this product overseas in 2005, primarily to the European thermal power industry. Through **The BC Energy Plan**, BC Hydro will issue a call for proposals for further electricity generation from wood residue and mountain pine beetle-infested timber.

GOVERNMENT TO USE HYBRID VEHICLES ONLY

The provincial government is continuing the effort to reduce greenhouse gas emissions and overall energy consumption.

As part of this effort, government has more than tripled the size of its hybrid fleet since 2005 to become one of the leaders in public sector use of hybrid cars.

Hybrids emit much less pollution than conventional gas and diesel powered vehicles and thus help to reduce greenhouse gases in our environment. They can also be more cost-effective as fuel savings offset the higher initial cost.

As of 2007, all new cars purchased or leased by the B.C. government are to be hybrid vehicles. The province also has new financial incentives to help local governments shift to hybrid vehicle fleets and help retrofit diesel vehicles.

Addressing Greenhouse Gas Emissions from Transportation

The BC Energy Plan: A Vision for Clean Energy Leadership takes a first step to incorporate transportation issues into provincial energy policy. Transportation is a major contributor to climate change and air quality problems. It presents other issues such as traffic congestion that slows the movement of goods and people. The fuel we use to travel around the province accounts for about 40 per cent of British Columbia's greenhouse gas emissions. Every time we drive or take a vehicle that runs on fossil fuels, we add to the problem, whether it's a train, boat, plane or automobile. Cars and trucks are the biggest source of greenhouse gas emissions and contribute to reduced air quality in urban areas.

The government is committed to reducing greenhouse gas emissions from the transportation sector and has committed to adopting California's tailpipe emission standards from greenhouse gas emissions and champion the national adoption of these standards.

British Columbians want a range of energy options for use at home, on the road and in day-to-day life. Most people use gasoline or diesel to keep their vehicles moving, but there are other options that improve our air quality and reduce greenhouse gas emissions.

Natural gas burns cleaner than either gasoline or propane, resulting in less air pollution. Fuel cell vehicles are propelled by electric motors powered by fuel cells, devices that produce electricity from hydrogen without combustion.

Cars that run on blends of renewable biofuels like ethanol and biodiesel emit lower levels of greenhouse gases and air pollutants. Electricity can provide an alternative to gasoline vehicles when used in hybrids and electric cars.

By working with businesses, educational institutions, non-profit organizations and governments, new and emerging transportation technologies can be deployed more rapidly at home and around the world. British Columbia will focus on research and development, demonstration projects, and marketing strategies to promote British Columbia's technologies to the world.

Implementing a Five Per Cent Renewable Fuel Standard for Diesel and Gasoline

The BC Energy Plan demonstrates British Columbia's commitment to environmental sustainability and economic growth by taking a lead role in promoting innovation in the transportation sector to reduce greenhouse gas emissions, improve air quality and help improve British Columbians' health and quality of life in the future. The plan will implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry. It will further support the federal action of increasing the ethanol content of gasoline to five per cent by 2010. The plan will also see the adoption of quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions. These renewable fuel standards are a major component and first step towards government's goal of reducing the carbon intensity of all passenger vehicles by 10 per cent by 2020.

Government will implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.

A Commitment to Extend British Columbia's Ground-breaking Hydrogen Highway

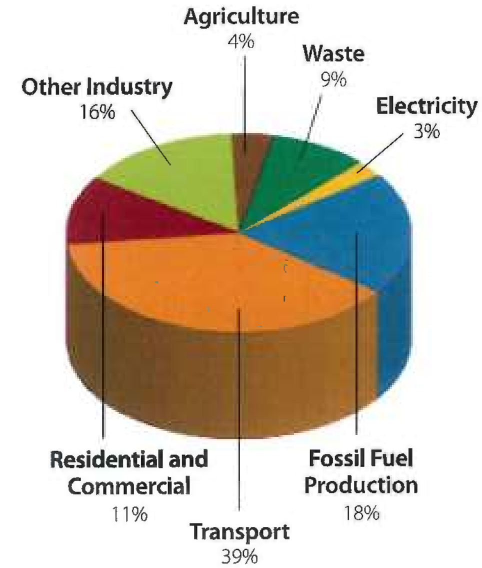
British Columbia is a world leader in transportation applications of the Hydrogen Highway, including the design, construction and safe operation of advanced hydrogen vehicle fuelling station technology. The Hydrogen Highway is a large scale, coordinated demonstration and deployment program for hydrogen and fuel cell technologies.

Vancouver's Powertech Labs established the world's first fast-fill, high pressure hydrogen fuelling station. The station anchors the Hydrogen Highway, which runs from Victoria through Surrey to Vancouver, North Vancouver, Squamish, and Whistler. Additional hydrogen fuelling stations are now in operation in Victoria and at the University of British Columbia.

The goal is to demonstrate and deploy various technologies and to one day see hydrogen filling stations around the province, serving drivers of consumer and commercial cars, trucks, and buses.

The unifying vision of the province's hydrogen and fuel cell strategy is to promote fuel cells and hydrogen technologies as a means of moving towards a sustainable energy future, increasing energy efficiency and reducing air pollutants and greenhouse gases. The Hydrogen Highway is targeted for full implementation by 2010. Canadian hydrogen and fuel cell companies have invested over $1 billion over the last five years, most of that in B.C. A federal-provincial partnership will be investing $89 million for fuelling stations and the world's first fleet of 20 fuel cell buses.

British Columbia will continue to be a leader in the new hydrogen economy by taking actions such as a fuel cell bus fleet deployment, developing a regulatory framework for micro-hydrogen applications, collaborating with neighbouring jurisdictions on hydrogen, and, in the long term, establishing a regulatory framework for hydrogen production, vehicles and fuelling stations.



B.C. Greenhouse Gas Emissions by Sector

(Based on 2004 data)
Source: Ministry of Environment

Cars and trucks are the biggest source of greenhouse gas emissions and reduce the quality of air in urban areas.

POLICY ACTIONS

ADDRESSING GREENHOUSE GAS EMISSIONS FROM TRANSPORTATION AND INCREASING INNOVATION

- **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.**

Vehicles that run on electricity, hydrogen and blends of renewable biofuels like ethanol and biodiesel emit lower levels of greenhouse gases and air pollutants.

LOCALMOTION FUND: REDUCING AIR POLLUTION IN YOUR COMMUNITY

The province has committed $40 million over four years to help build cycling and pedestrian pathways, improve safety and accessibility, and support children's activity programs in playgrounds.

This fund will help local government shift to hybrid vehicle fleets and help retrofit diesel vehicles which will help reduce air pollution and ensure vibrant and environmentally sustainable communities. This investment will also include expansion of rapid transit and support fuel cell vehicles.

Promote Energy Efficiency and Alternative Energy

It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar thermal and geothermal. Working with municipalities, utilities and other stakeholders the provincial government will promote energy efficiency and alternative energy systems, such as solar thermal and geothermal throughout the province.

Environmental Leadership in Action

The BC Energy Plan: A Vision for Clean Energy Leadership complements other related cross-government initiatives that include supporting transportation demand management, reducing traffic congestion and better integrating land use and transportation planning. These plans include actions across a broad range of activities. Some key initiatives and recent announcements include:

- Extending the tax break on hybrid vehicle purchases beyond the current March 2008 deadline.
- Government to purchase hybrid vehicles exclusively.
- Reducing diesel emissions through new financial incentives to help municipalities shift to hybrid vehicle fleets and retrofit diesel vehicles with cleaner technologies.
- Green Ports:
  - Working with ports and the shipping sector to reduce emissions from their activities and marine vessels.
  - The Port of Vancouver has established idle reduction zones and has reduced truck emissions with its container reservation system which has reduced average wait times from two hours to approximately 20 minutes.
  - The port is also evaluating port-side electrification which would see vessels using shore-side electrical power while berthed rather than diesel power.
- Improving upon the monitoring and reporting of air quality information.
- Highway Infrastructure and Rapid Transit Infrastructure funding including the Gateway Program, the Border Infrastructure Program, high occupancy vehicle lanes, construction of the Rapid Transit Canada Line linking Richmond, the Vancouver International Airport and Vancouver, and the Rapid Transit Evergreen Line linking Burnaby to Coquitlam.
- Expanding the AirCare on the Road Program to the Lower Fraser Valley and other communities.
- Implementing the LocalMotion Program for capital projects to improve physical fitness and safety, reduce air pollution and meet the diverse needs of British Columbians.

A Choice of Electricity Options

The range of supply options, both large and small, for British Columbia include:

Bioenergy: Bioenergy is derived from organic biomass sources such as wood residue, agricultural waste, municipal solid waste and other biomass and may be considered a carbon-neutral form of energy, because the carbon dioxide released by the biomass when converted to energy is equivalent to the amount absorbed during its lifetime.

A number of bioenergy facilities operate in British Columbia today. Many of these are "cogeneration" plants that create both electricity and heat for on-site use and in some cases, sell surplus electricity to BC Hydro.

Reliability[1]: FIRM
Estimated Cost[5]: $75 – $91

Coal Thermal Power: The BC Energy Plan establishes a zero emission standard for greenhouse gas emissions from coal-fired plants. This will require proponents of new coal facilities to employ clean coal technology with carbon capture and sequestration to ensure there are no greenhouse gas emissions.

Reliability[1]: FIRM
Estimated Cost[5,6]: $67– $82

Geothermal: Geothermal power is electricity generated from the earth. Geothermal power production involves tapping into pockets of superheated water and steam deep underground, bringing them to the surface and using the heat to produce steam to drive a turbine and produce electricity. British Columbia has potential high temperature (the water is heated to more than 200 degrees Celsius) geothermal resources in the coastal mountains and lower temperature resources in the interior, in northeast British Columbia and in a belt down the Rocky Mountains. Geothermal energy's two main advantages are its consistent supply, and the fact that it is a clean, renewable source of energy.

Reliability[1]: FIRM
Estimated Cost[2]: $44 - $60

Hydrogen and Fuel Cell Technology:
British Columbia companies are recognized globally for being leaders in hydrogen and fuel cell technology for mobile, stationary and micro applications. For example, BC Transit's fuel cell buses are planned for deployment in Whistler in 2009.

Reliability[1]: FIRM
Estimated Cost[2]: n/a

[1] Reliability refers to energy that can be depended on to be available whenever required
[2] Source: BC Hydro's 2006 IEP Volume 1 of 2 page 5-6
[3] Based on a 500 MW super ciritcal pulverized coal combustion unit. The BC Energy Plan requires coal power to meet zero GHG emissions
[4] Based on a 250 MW combined cycle gas turbine plant. The BC Energy Plan requires coal power to meet zero GHG emissions
[5] Source: BC Hydro's F2006 Open Call for Power Report
[6] These costs do not reflect the costs of zero GHG emissions for coal thermal power

GOVERNMENT'S COMMITMENT TO THE ENVIRONMENT – THE ENVIRONMENTAL ASSESSMENT PROCESS

The environmental assessment process in British Columbia is an integrated review process for major projects that looks at potential environmental, community and First Nation, health and safety, and socioeconomic impacts. Through the environmental assessment process, the potential effects of a project are identified and evaluated early, resulting in improved project design and helping to avoid costly mistakes for proponents, governments, local communities and the environment.

An assessment is begun when a proposed project that meets certain criteria under the ***Environmental Assessment Act*** makes an application for an environmental assessment certificate. Each assessment will usually include an opportunity for all interested parties to identify issues and provide input; technical studies of the relevant environmental, social, economic, heritage and/or health effects of the proposed project; identification of ways to prevent or minimize undesirable effects and enhance desirable effects; and consideration of the input of all interested parties in compiling the assessment findings and making decisions about project acceptability. The review is concluded when a decision is made to issue or not issue an environmental assessment certificate. Industrial, mining, energy, water management, waste disposal, food processing, transportation and tourist destination resort projects are generally subject to an environmental assessment.

WHAT IS THE DIFFERENCE BETWEEN FIRM AND INTERMITTENT ELECTRICITY?

Firm electricity refers to electricity that is available at all times even in adverse conditions. The main sources of reliable electricity in British Columbia include large hydroelectric dams, and natural gas. This differs from intermittent electricity, which is limited or is not available at all times. An example of intermittent electricity would be wind which only produces power when the wind is blowing.

Large Hydroelectric Dams: The chief advantage of a hydro system is that it provides a reliable supply with both dependable capacity and energy, and a renewable and clean source of energy. Hydropower produces essentially no carbon dioxide.

Site C is one of many resource options that can help meet BC Hydro's customers' electricity needs. No preferred option has been selected at this time; however; it is recognized that the Province will need to examine opportunities for some large projects to meet growing demand.

As part of **The BC Energy Plan**, BC Hydro and the Province will enter into initial discussions with First Nations, the Province of Alberta and communities to discuss Site C to ensure that communications regarding the potential project and the processes being followed are well known. The purpose of this step is to engage the various parties up front to obtain input for the proposed engagement process. The decision-making process on Site C includes public consultation, environmental impact assessments, obtaining a Certificate of Public Convenience and Necessity, obtaining an Environmental Assessment Certificate and necessary environmental approvals, and approval by Cabinet.

Reliability[1]: FIRM
Estimated Cost[2]: $43 - $62

Natural Gas: Natural gas is converted into electricity through the use of gas fired turbines in medium to large generating stations; particularly high efficiencies can be achieved through combining gas turbines with steam turbines in the combined cycle and through reciprocating engines and mini and macro turbines. Combined cycle power generation using natural gas is the cleanest source of power available using fossil fuels. Natural gas provides a reliable supply with both dependable capacity and firm energy.

Reliability[1]: FIRM
Estimated Cost[2 6]: $48 - $100

Small Hydro: This includes run-of-river and micro Hydro. These generate electricity without altering seasonal flow characteristics. Water is diverted from a natural watercourse through an intake channel and pipeline to a powerhouse where a turbine and generator convert the kinetic energy in the moving water to electrical energy.

Twenty-nine electricity purchase agreements were awarded to small waterpower producers by BC Hydro in 2006. These projects will generate approximately 2,851 gigawatt hours of electricity annually (equivalent to electricity consumed by 285,000 homes in British Columbia). There are also 32 existing small hydro projects in British Columbia that generate 3,500 gigawatt hours (equivalent to electricity consumed by 350,000 homes in British Columbia).

Reliability[1]: INTERMITTENT
Estimated Cost[3]: $60 – $95

Solar: With financial support from the Ministry of Energy, Mines and Petroleum Resources, the "Solar for Schools" program has brought clean solar photovoltaic electricity to schools in Vernon, Fort Nelson, and Greater Victoria.

The BC Sustainable Energy Association is leading a project which targets installing solar water heaters on 100,000 rooftops across British Columbia.

Reliability[1]: INTERMITTENT
Estimated Cost[2]: $700 - $1700

Tidal Energy: A small demonstration project has been installed at Race Rocks located west-southwest of Victoria. The Lester B. Pearson College of the Pacific, the provincial and federal government, and industry have partnered to install and test a tidal energy demonstration turbine at Race Rocks. The project will generate about 77,000 kilowatt hours on an annual basis (equivalent to electricity consumed by approximately eight homes).

Reliability[1]: INTERMITTENT
Estimated Cost[2]: $100 - $360

Wind: British Columbia has abundant, widely distributed wind energy resources in three areas: the Peace region in the Northeast; Northern Vancouver Island; and the North Coast. Wind is a clean and renewable source that does not produce air or water pollution, greenhouse gases, solid or toxic wastes.

Three wind generation projects have been offered power purchase contracts in BC Hydro's 2006 Open Call for Power. These three projects will have a combined annual output of 979 gigawatt hours of electricity (equivalent to electricity consumed by 97,900 homes).

Reliability[1]: INTERMITTENT
Estimated Cost[5]: $71 – $74

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[1] Reliability refers to energy that can be depended on to be available whenever required
[2] Source: BC Hydro's 2006 IEP Volume 1 of 2 page 5-6
[3] Based on a 500 MW super ciritcal pulverized coal combustion unit. The BC Energy Plan requires coal power to meet zero GHG emissions
[4] Based on a 250 MW combined cycle gas turbine plant.
[5] Source: BC Hydro's F2006 Open Call for Power Report
[6] These costs do not reflect the costs of zero net GHG emissions for natural gas

RACE ROCKS TIDAL ENERGY PROJECT

Announced in early 2005, this demonstration project between the provincial and federal governments, industry, and Pearson College is producing zero emission tidal power at the Race Rocks Marine Reserve on southern Vancouver Island. Using a current-driven turbine submerged below the ocean surface, the project is producing about 77,000 kilowatt hours of electricity per year, enough to meet the needs of approximately eight households. The knowledge gained about tidal energy will help our province remain at the forefront of clean energy generation technology.

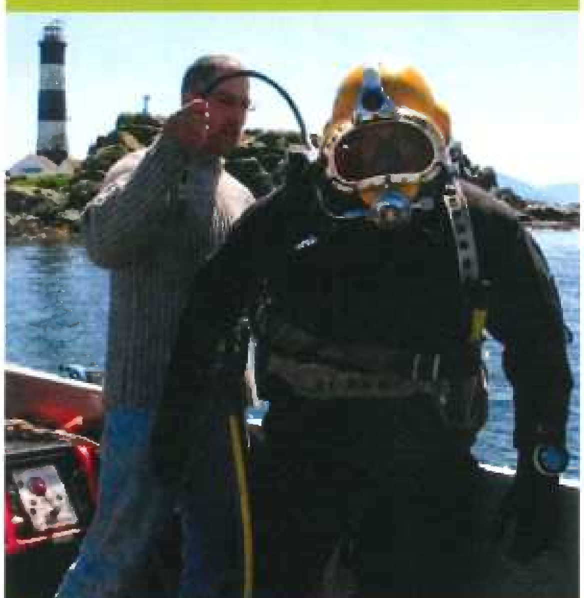


Table 1: Summary of Resource Options

Description	Estimated Cost [1] $ /megawatt hour	Reliable[2]	Greenhouse gas emissions[3] tonnes per gigawatt hour
Energy conservation/ efficiency	32 – 76	Yes	0
Large hydroelectric	43 – 62	Yes	0
Natural gas	48 – 100[8]	Yes	0 – 350[4 8]
Coal	67 – 82[9 10]	Yes	0 – 855[5 9]
Biomass	75 – 91[10]	Yes	0 – 500[6]
Geothermal	44 – 60	Yes	0 – 10
Wind	71 – 74[10]	Depends on the availability and speed of wind	0
Run-of-river small hydro	60 – 95[10]	Depends on the flow of water, which varies throughout the year	0
Ocean (wave and tidal)	100 – 360[7]	Future supply option which has great potential for British Columbia	0
Solar	700 – 1700[7]	Depends on location, cloud cover, season, and time of day	0

1 Source: BC Hydro's 2006 Integrated Electricity Plan Volume 1 of 2, page 5-6
2 Reliability refers to energy that can be depended on to be available whenever required
3 Source: BC Hydro's 2006 Integrated Electricity Plan, Volume 2 of 2, Appendix F page 5-14 and Table 10-2
4 Based on a 250 MW combined cycle gas turbine plant
5 Based on a 500 MW supercritical pulverized coal combustion unit
6 GHG are 0 for wood residue and landfill gas. GHG is 500 tonnes per gigawatt hour for municipal solid waste
7 Source: BC Hydro's 2004 Integrated Electricity Plan, page 69
8 The BC Energy Plan requires natural gas plants to offset to zero net greenhouse gas emissions. These costs do not reflect the costs of zero net GHG emissions
9 The BC Energy Plan requires zero greenhouse gas emissions from any coal thermal electricity facilities
The costs do not include the costs of requiring zero emissions from coal thermal power
10 Source: BC Hydro's F2006 Open Call for Power Report

The majority of B.C.'s electricity requirements over the next 10 years can be achieved through increased conservation by all British Columbians and new electricity from independent power producers.

British Columbia's Strength in Electricity Diversity

British Columbia is truly fortunate to have a wide variety of future supply options available to meet our growing demand for energy. A cost effective way to meet that demand is to conserve energy and be more energy efficient. However, British Columbia will still need to bring new power on line to meet demand growth in the years ahead. In order to ensure we have this critical resource available to British Columbians when they need it, government will be looking to secure a range of made-in-B.C. power to serve British Columbians in the years ahead.

Government's goal is to encourage a diverse mix of resources that represent a variety of technologies. Some resource technologies, such as large and small hydro, thermal power, wind and geothermal provide well-established, commercially available sources of electricity. Other emerging technologies that are not yet widely used include large ocean wave and tidal power, solar, hydrogen and advanced coal technologies.

2004 Total Electricity Production by Source (% of total)

	Other Renewables	Hydro Electric	Nuclear	Waste and Biomass	Natural Gas	Diesel Oil	Coal	TOTAL
British Columbia	**0.0**	**92.8**	**0.0**	**1.0**	**6.0**	**0.2**	**0.0**	**100**
Alberta	2.3	4.4	0.0	0.0	12.0	2.6	78.7	100
Australia	0.3	6.9	0.0	0.6	12.3	0.70	79.2	100
California	10.7	17.0	14.5	0.0	37.7	0.0	20.1	100
Denmark	16.3	0.1	0.0	8.8	24.7	4.0	46.1	100
Finland	0.4	17.6	26.5	12.4	14.9	0.7	27.5	100
France	0.2	11.3	78.3	1.0	3.2	1.0	5.0	100
Germany	4.2	4.5	27.1	2.6	10.0	1.6	50.0	100
Japan	0.4	9.5	26.1	1.9	22.6	12.3	27.2	100
Norway	0.3	98.8	0.0	0.5	0.3	0.0	0.1	100
Ontario	1.8	24.8	49.7	0.0	5.2	0.5	18.0	100
Oregon	2.3	64.4	0.0	0.0	26.3	0.1	6.9	100
Quebec	0.7	94.5	3.2	0.0	0.1	1.5	0.0	100
United Kingdom	0.5	1.9	20.2	2.1	40.3	1.2	33.8	100
Washington	2.3	70.0	8.8	0.0	8.6	0.1	10.2	100

SHARING SOLUTIONS ON ELECTRICITY

The BC Energy Plan has a goal that most of B.C.'s electricity requirements over the next 10 years can be achieved through increased conservation and energy efficiency by all British Columbians, coupled with generation by independent power producers. However, these new projects take time to plan and implement. In addition, many of these sources provide limited amounts of firm supply. The province will also need to consider options for new, large scale sources to meet forecasted demand growth in the next 10 to 20 years. Large scale options could include Site C, large biomass facilities, clean coal or natural gas plants. As with all large scale undertakings, these kinds of projects will require years of lead time to allow for careful planning, analysis, consultation and construction.

Perhaps the biggest challenge facing British Columbians is simply to begin choosing our electricity future together. Demand for electricity is projected to grow by up to 45 per cent over the next 20 years. To meet this projected growth we will need to conserve more, and obtain more electricity from small power producers and large projects. Given the critical importance of public participation and stakeholder involvement in addressing the challenges and choices of meeting our future electricity needs, government and BC Hydro will seek and share solutions.

Rapid expansion of our energy sector means a growing number of permanent, well-paying employment opportunities are available.

Taking Action to Meet the Demand for Workers

The energy sector has been a major contributor to British Columbia's record economic performance since 2001. **The BC Energy Plan** focuses on four under-represented groups that offer excellent employment potential: Aboriginal people, immigrants, women and youth.

At the same time, the energy sector must overcome a variety of skills training and labour challenges to ensure future growth.

These challenges include:

- An aging workforce that upon retirement will leave a gap in experience and expertise.
- Competition for talent from other jurisdictions.
- Skills shortages among present and future workers.
- Labour market information gaps due to a lack of in-depth study.
- The need to coordinate immigration efforts with the federal government.
- The need for greater involvement of under-represented energy sector workers such as Aboriginal people, immigrants, women, and youth.
- A highly mobile workforce that moves with the opportunities.
- The need to improve productivity and enhance competitiveness.

Innovative, practical and timely skills training, and labour management is required to ensure the energy sector continues to thrive. As part of **The BC Energy Plan**, government will work collaboratively with industry, communities, Aboriginal people, education facilities, the federal government and others to define the projected demand for workers and take active measures to meet those demands.

Attract Highly Skilled Workers

Demographics show that those born at the height of the baby boom are retired or nearing retirement, leaving behind a growing gap in skills and expertise. Since this phenomenon is taking place in most western nations, attracting and retaining skilled staff is highly competitive.

To ensure continued energy sector growth, we need to attract workers from outside the province, particularly for the electricity, oil and gas, and heavy construction industries where the shortage is most keenly felt. At this time, a significant increase in annual net migration of workers from other provinces and from outside Canada is needed to complement the existing workforce.

Government and its partners are developing targeted plans to attract the necessary workers. These plans will include marketing and promoting energy sector jobs as a career choice.

Develop a Robust Talent Pool of Workers

It is vital to provide the initial training to build a job-ready talent pool in British Columbia, as well as the ongoing training employees need to adapt to changing energy sector technologies, products and requirements. We can ensure a thriving pool of talent in British Columbia by retraining skilled employees who are without work due to downturns in other industries. Displaced workers from other sectors and jurisdictions may require some retraining and new employees may need considerable skills development.

Another way to help ensure there are enough skilled energy sector workers in the years ahead is to educate and inform young people today. By letting high school students know about the opportunities, they can consider their options and make the appropriate training and career choices. Government will work to enhance information relating to energy sector activities in British Columbia's school curriculum in the years ahead.

Retain Skilled Workers

Around the world, energy facility construction and operations are booming, creating fierce, global competition for skilled workers. While British Columbia has much to offer, it is critical that our jurisdiction presents a superior opportunity to these highly skilled and mobile workers. That is why we need to ensure our workplaces are safe, fair and healthy and our communities continue to offer an unparalleled lifestyle with high quality health care and education, affordable housing, and readily available recreation opportunities in outstanding natural settings.

Inform British Columbians

To be effective in filling energy sector jobs with skilled workers, British Columbians need to be informed and educated about the outstanding opportunities available. As part of **The BC Energy Plan**, a comprehensive public awareness and education campaign based on sound labour market analysis will reach out to potential energy sector workers. This process will recognize and address both the potential challenges such as shift work and remote locations as well as the opportunities, such as obtaining highly marketable skills and earning excellent compensation.

Be Among the Most Competitive Oil and Gas Jurisdictions in North America

Since 2001, British Columbia's oil and gas sector has grown to become a major force in our provincial economy, employing tens of thousands of British Columbians and helping to fuel the province's strong economic performance. In fact, investment in the oil and gas sector was $4.6 billion in 2005. The oil and gas industry contributes approximately $1.95 billion annually or seven per cent of the province's annual revenues.

The BC Energy Plan is designed to take B.C.'s oil and gas sector to the next level to enhance a sustainable, thriving and vibrant oil and gas sector in British Columbia. With a healthy, competitive oil and gas sector comes the opportunity to create jobs and build vibrant communities with increased infrastructure and services, such as schools and hospitals. Of particular importance is an expanding British Columbia-based service sector.

There is a lively debate about the peak of the world's oil and gas production and the impacts on economies, businesses and consumers. A number of countries, such as the UK, Norway and the USA, are experiencing declining fossil fuel production from conventional sources. Energy prices, especially oil prices have increased and are more volatile than in the past. As a result, the way energy is produced and consumed will change, particularly in developed countries.

The plan is aimed at enhancing the development of conventional resources and stimulating activity in relatively undeveloped areas such as the interior basins – particularly the Nechako Basin. It will also foster the development of unconventional resources such as as tight gas, shale gas, and coalbed gas. The plan will further efforts to work with the federal government, communities and First Nations to advance offshore opportunities.

The challenge for British Columbia in the future will be to continue to find the right balance of economic, environmental and social priorities to allow the oil and gas sector to succeed, while protecting our environment and improving our quality of life.

The New Relationship and Oil and Gas

Working together with local communities and First Nations, the provincial government will continue to share in the many benefits and opportunities created through the development of British Columbia's oil and gas resources.

Government is working to ensure that oil and gas resource management includes First Nations' interests, knowledge and values. Government has recently concluded consultation agreements for oil and gas resource development with First Nations in Northeast British Columbia. These agreements increase clarity in the process and will go a long way to enhancing our engagement with these First Nations.

Government will continue to pursue opportunities to share information and look for opportunities to facilitate First Nations' employment and participation in the oil and gas industry to ensure that Aboriginal people benefit from the continued growth and development of British Columbia's resources.

POLICY ACTIONS

ENVIRONMENTALLY RESPONSIBLE OIL AND GAS DEVELOPMENT

- **Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.**
- **Establish policies and measures to reduce air emissions in coordination with the Ministry of Environment.**
- **Best coalbed gas practices in North America. Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.**
- **Enhance the Oil and Gas Environmental Stewardship Program, ensuring sound environmental, land and resource management.**

***The BC Energy Plan** adopts a triple bottom line approach to competitiveness, with an attractive investment climate, environmentally sustainable development of B.C.'s abundant resources, and by benefiting communities and First Nations.*

While striving to be among the most competitive oil and gas jurisdictions in North America, the province will focus on maintaining and enhancing its strong competitive environment for the oil and gas industry. This encompasses the following components:

- A competitive investment climate.
- An abundant resource endowment.
- Environmental responsibility.
- Social responsibility.

Leading in Environmentally and Socially Responsible Oil and Gas Development

The BC Energy Plan emphasizes conservation, energy efficiency, and the environmental and socially responsible management of the province's energy resources. It outlines government's efforts to meet this objective by working collaboratively with involved and interested parties, including affected communities, landowners, environmental groups, First Nations, the regulator (the Oil and Gas Commission), industry groups and others. Policy actions will support ways to address air emissions, impacts on land and wildlife habitat, and water quality.

The oil and gas sector in British Columbia accounts for approximately 18 per cent of greenhouse gas air emissions in the province. The main sources of air emissions from the oil and gas sector are flaring, fugitive gases, gas processing and compressor stations. While these air emissions have long been part of the oil and gas sector, they have also been a source of major concern for oil and gas communities.

Eliminate Flaring from Oil and Gas Producing Wells and Production Facilities By 2016

Through **The BC Energy Plan**, government has committed to eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011. In addition, government will adopt policies to reduce natural gas flaring and venting at test sites and pipelines, and encourage compressor station efficiency to cut back emissions. Government will also explore opportunities and new technologies for safe, underground disposal of carbon dioxide or sequestration from oil and gas facilities. Sequestration is considered a cost effective mitigation strategy in reducing carbon dioxide emissions.

Enhance Carbon Dioxide Sequestration in British Columbia

British Columbia is a member of the Plains CO2 Reduction (PCOR) Partnership composed of nearly 50 private and public sector groups from nine states and three Canadian provinces that is assessing the technical and economic feasibility of capturing and storing carbon dioxide emissions from stationary sources in western sedimentary basins.

B.C. is also a member of the West Coast Regional Carbon Sequestration Partnership, made up of west coast state and provincial government ministries and agencies. This partnership has been formed to pursue carbon sequestration opportunities and technologies.

To facilitate and foster innovation in sequestration, government will develop market oriented requirements with a graduated schedule. In consultation with stakeholders, a timetable will be developed along with increasing requirements for sequestration.

BRITISH COLUMBIA COMPANIES RECOGNIZED AS WORLD ENERGY TECHNOLOGY INNOVATORS

The leadership of British Columbian companies can be seen in all areas of the energy sector through innovative, industry leading technologies.

Production of a new generation of chemical injection pump for use in the oil and gas industry is beginning. The pumps, developed and built in British Columbia, are the first solar powered precision injection pumps available to the industry. They will reduce emissions by replacing traditional gas powered injection systems for pipelines.

Other solar technologies developed in British Columbia provide modular power supplies in remote locations all over the globe for marine signals, aviation lights and road signs.

Roads in B.C. and around the world are hosting demonstrations of fuel cell vehicles built with British Columbia technology. Thanks to the first high pressure hydrogen fuelling station in the world, compatible fuel cell vehicles in B.C. can carry more fuel and travel farther than ever before.

The **Innovative Clean Energy Fund** will help to build B.C.'s technology cluster and keep us at the forefront of energy technology development.

Government will work to improve oil and gas tenure policies as well as develop new guidelines to determine areas that require special consideration prior to tenure approval.

POLICY ACTIONS

OFFSHORE OIL AND GAS DEVELOPMENT

- **Continue to work to lift the federal moratorium on offshore exploration and development and reiterate the intention to simultaneously lift the provincial moratorium.**
- **Work with the federal government to ensure that offshore oil and gas resources are developed in a scientifically sound and environmentally responsible way.**
- **Participate in marine and environmental planning to effectively manage marine areas and offshore oil and gas basins.**
- **Develop and implement a comprehensive community engagement program to establish a framework for a benefits sharing agreement resulting from offshore oil and gas development for communities, including First Nations.**

Environmental Stewardship Program

In 2004, the Ministry of Energy, Mines and Petroleum Resources initiated the Oil and Gas Environmental Stewardship Program having two components: the Environmental Policy Program and the Environmental Resource Information Project. The Environmental Policy Program identifies and mitigates environmental issues in the petroleum sector focusing on policy development in areas such as environmental waste management, habitat enhancement, planning initiatives, wildlife studies for oil and gas priority areas and government best management practices. Some key program achievements include the completion of guidelines for regulatory dispersion modeling, research leading to the development of soil quality guidelines for soluble barium, a key to northern grasses and their restorative properties for remediated well sites, and moose and caribou inventories in Northeast British Columbia.

The Environmental Resource Information Project is dedicated to increasing opportunities for oil and gas development, through the collection of necessary environmental baseline information. These projects are delivered in partnership with other agencies, industry, communities and First Nations.

The BC Energy Plan enhances the important Oil and Gas Environmental Stewardship Program. This will improve existing efforts to manage waste and preserve habitat, and will establish baseline data as well as development and risk mitigation plans for environmentally sensitive areas. Barriers need to be identified and steps taken for remediation, progressive reclamation, and waste management.

Best Coalbed Gas Practices in North America

Government will continue to encourage coalbed gas development with the intent of demonstrating that British Columbia is a leading socially and environmentally responsible coalbed gas developing jurisdiction. Coalbed gas, also known as coalbed methane, is natural gas found in coal seams. It is one of the cleanest burning of all fossil fuels. Proponents wanting to develop coalbed gas must adopt the following best practices:

- Fully engage local communities and First Nations in all stages of development.
- Use the most advanced technology and practices that are commercially viable to minimize land and aesthetic disturbances.
- Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.
- Meet any other conditions the Oil and Gas Commission may apply.
- Demonstrate the company's previous experience with coalbed gas development, and information must be made publicly available as to how the company plans to meet and be accountable for these best practices.

Ensuring Offshore Oil and Gas Resources are Developed in a Scientifically Sound and Environmentally Responsible Way

The BC Energy Plan includes actions related to the province's offshore oil and gas resources. Since 1972, Canada and British Columbia have each had a moratorium in place on offshore oil and gas exploration and development. With advanced technology and

British Columbia's oil and gas industry supports thousands of well-paying jobs, helps drive the economy and provides revenues to sustain public services.

positive experiences in other jurisdictions, a compelling case exists for assessing British Columbia's offshore resource potential.

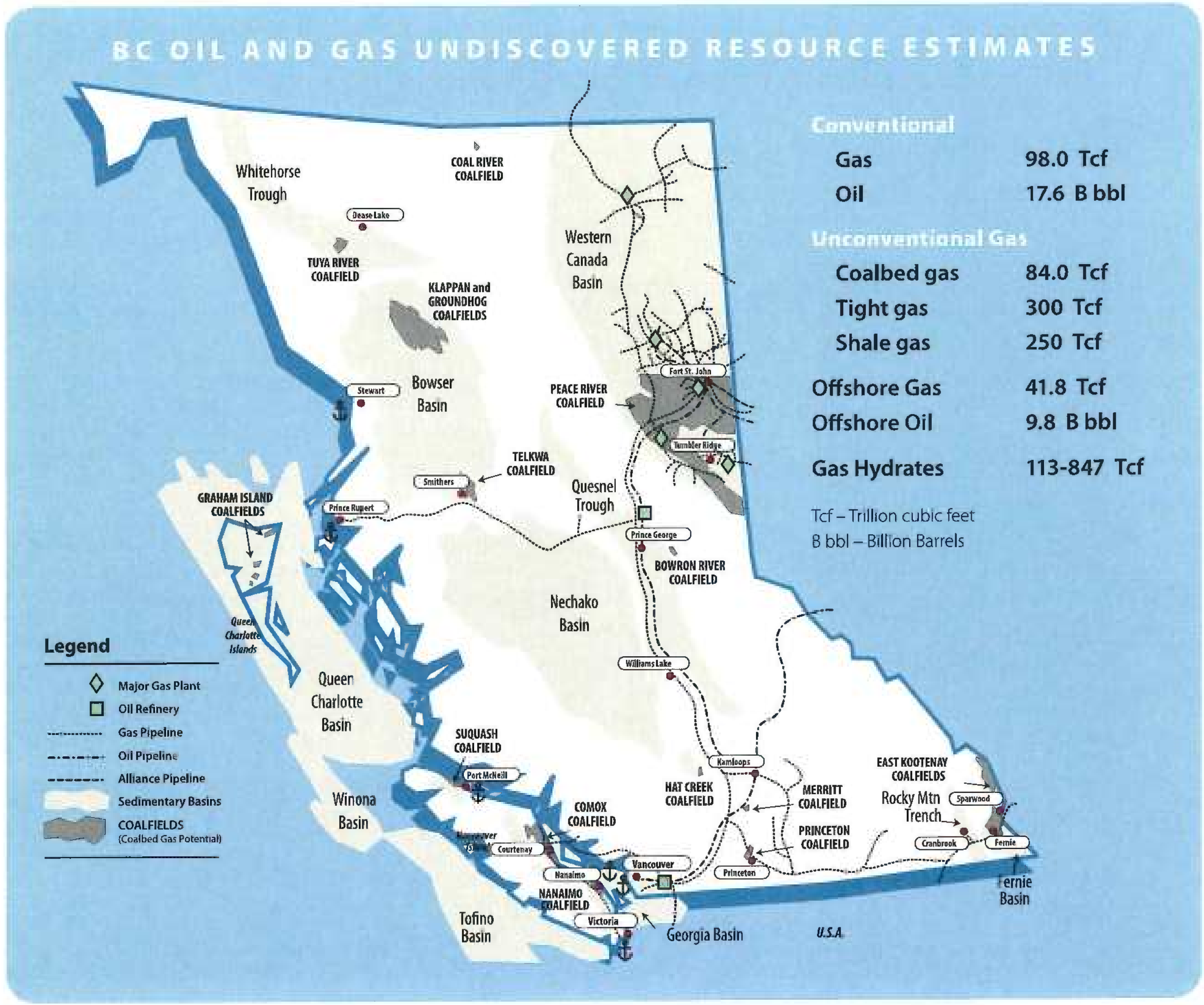
Government will work with coastal communities, First Nations, the federal government, environmental organizations, and others to ascertain the benefits and address the concerns associated with offshore oil and gas development.

Maintaining B.C.'s Competitive Advantage as an Oil and Gas Jurisdiction

British Columbia's oil and gas industry is thriving thanks to high resource potential, industry and service sector expertise, and a competitive investment climate that includes a streamlined regulatory environment. To attract additional investment in British Columbia's oil and gas industry, we need to compete aggressively with other jurisdictions that may offer lower taxes or other investment incentives.

Another key way to be more competitive is by spurring activity in underdeveloped areas while heightening activity in the northeast, where our natural gas industry thrives. The province will work with industry to develop new policies and technologies for enhanced resource recovery making, it more cost-effective to develop British Columbia's resources.

By increasing our competitiveness, British Columbians can continue to benefit from well-paying jobs, high quality social infrastructure and a thriving economy.



British Columbia's Enormous Natural Gas Potential

The oil and gas sector will continue to play an important role in British Columbia's future energy security. Our province has enormous natural gas resource potential and opportunities for significant growth. **The BC Energy Plan** facilitates the development of B.C.'s resources.

British Columbia has numerous sedimentary basins, which contain petroleum and natural gas resources. In north-eastern British Columbia, the Western Canada Sedimentary Basin is the focus of our thriving natural gas industry. The potential resources in the central and northern interior of the province, the Nechako and Bowser Basins and Whitehorse Trough, have gone untapped.

The delayed evaluation and potential development of these areas is largely due to geological and physical obstructions that make it difficult to explore in the area. Volcanic rocks that overlay the sedimentary package combined with complex basin structures, have hindered development.

The BC Energy Plan is aimed at enhancing the development of conventional resources and stimulating activity in undeveloped areas such as the interior basins – particularly the Nechako Basin. It will also foster the development of unconventional resources and take a more stringent approach on coalbed gas to meet higher environmental standards.

Attracting Investment and Developing our Oil and Gas Resources

The BC Energy Plan promotes competitiveness by setting out a number of important regulatory and fiscal measures including: monitoring British Columbia's competitive ranking, considering a Net Profit Royalty Program, promoting a B.C. service sector, harmonizing and streamlining regulations, and developing a Petroleum Registry to examine royalty and tenure incentives, and undertaking geoscience programs.

Establishment of a Petroleum Registry

The establishment of a petroleum registry that functions as a central database will improve the quality and management of key volumetric, royalty and infrastructure information associated with British Columbia's oil and gas industry and promote competition while providing transparency around oil and gas activity.

NEEMAC: SUCCESS THROUGH COMMUNICATION

As energy, mining and petroleum resource development increases in northeast B.C., so too does the need for input from local governments, First Nations, community groups, landowners and other key stakeholders. In 2006, the Northeast Energy and Mines Advisory Committee (NEEMAC) was created to provide an inclusive forum for representative organizations to build relationships with each other, industry and government to provide input on Ministry policy, and recommend innovative solutions to stakeholder concerns.

Since its creation, NEEMAC has identified and explored priority concerns, and is beginning to find balanced solutions related to environmental, surface disturbance, access and landowner rights issues. The Ministry is committed to implementing recommendations that represent the broad interests of community, industry and government and expects that the committee will continue to provide advice on energy, mining and petroleum development issues in support of **The BC Energy Plan**.

An opportunity to increase competitiveness exists in British Columbia's Interior Basins – namely the Nechako, Bowser and Whitehorse Basins – where considerable resource potential is known to exist.

Increasing Access

In addition to regulatory and fiscal mechanisms, the plan addresses the need for improving access to resources. Pipelines and road infrastructure are critical factors in development and competitiveness. **The BC Energy Plan** calls for new investment in public roads and other infrastructure. It will see government establish a clear, structured infrastructure royalty program, combining road and pipeline initiatives and increasing development in under-explored areas that have little or no existing infrastructure.

Developing Conventional and Unconventional Oil and Gas Resources

To support investment in exploration, **The BC Energy Plan** calls for partnerships in research and development to establish reliable regional data, as well as royalty and tenure incentives. The goal is to attract investment, create well-paying jobs, boost the regional economy and produce economic benefits for all British Columbians. We can be more competitive by spurring activity in underdeveloped areas while heightening activity in the northeast where our natural gas industry thrives. The plan advocates working with industry to develop new policies and technology to enhance resource recovery, including oil in British Columbia.

Improve Regulations and Research

The province remains committed to continuous improvement in the regulatory regime and environmental management of conventional and unconventional oil and gas resources. The opportunities for enhancing exploration and production of tight gas, shale gas, and coalbed gas will also be assessed and supported by geoscience research and programs. **The BC Energy Plan** calls for collaboration with other government ministries, agencies, industry, communities and First Nations to develop the oil and gas resources in British Columbia.

Focus on Innovation and Technology Development

The BC Energy Plan also calls for supporting the development of new oil and gas technologies. This plan will lead British Columbia to become an internationally recognized centre for technological advancements and commercialization, particularly in environmental management, flaring, carbon sequestration and hydrogeology. The service sector has noted it can play an important role in developing and commercializing new technologies; however, the issue for companies is accessing the necessary funds.

THE HUB OF B.C.'S OIL AND GAS SECTOR

Oil and gas is benefiting all British Columbians - not just those living in major centres. Nowhere is this more apparent than in booming Fort St. John, which has rapidly become the oil and gas hub of the province. Since 2001, more than 1,400 people have moved to the community, an increase of 6.3 per cent and two per cent faster growth than the provincial average. Construction permits are way up - from \$48.7 million in 2004, to \$50.6 million in 2005, to over \$123 million in 2006. In the past five years, over 1,000 new companies have been incorporated in Fort St. John, as young families, experienced professionals, skilled trades-people and many others move here from across the country.

POLICY ACTIONS

BE AMONG THE MOST COMPETITIVE OIL AND GAS JURISDICTIONS IN NORTH AMERICA

- **Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdictions in North America.**
- **Enhance infrastructure to support the development of oil and gas in British Columbia and address impediments to economic development such as transportation and labour shortages.**
- **Encourage the development of conventional and unconventional resources.**
- **Support the growth of British Columbia's oil and gas service sector.**
- **Promote exploration and development of the Interior basins with a priority focus on the Nechako Basin.**
- **Encourage the development of new technologies.**
- **Add value to British Columbia's oil and gas industry by assessing and promoting the development of additional gas processing facilities in the province.**

Technology Transfer Incentive Program

A new Oil and Gas Technology Transfer Incentive Program will be considered to encourage the research, development and use of innovative technologies to increase recoveries from existing reserves and encourage responsible development of new oil and gas reserves. The program could recover program costs over time through increased royalties generated by expanded development and production of British Columbia's petroleum resources.

Scientific Research and Experimental Development

The BC Energy Plan supports the British Columbia Scientific Research and Experimental Development Program, which provides financial support for research and development leading to new or improved products and processes. Through credits or refunds, the expanded program could cover project costs directly related to commercially applicable research, and development or demonstration of new or improved technologies conducted in British Columbia that facilitate expanded oil and gas production.

Research and Development

The BC Energy Plan calls for using new or existing research and development programs for the oil and gas sector. Government will develop a program targeting areas in which British Columbia has an advantage such as well completion technology and hydrogeology.

A program to encourage oil and gas innovation and research in British Columbia's post-secondary institutions will be explored. These opportunities will be explored in partnership with the Petroleum Technology Alliance Canada and as part of the April 2006 Memorandum of Understanding between British Columbia and Alberta on Energy Research, Technology Development and Innovation.

Together with the Oil and Gas Centre of Excellence in Fort St. John, an oil and gas technology incubator, a site which provides innovators with space to build prototypes and carry out testing as well as providing business infrastructure and assistance accessing additional support will be established, allowing entrepreneurs to develop and test new innovations and commercialize new, innovative technologies and processes.

Nechako Initiative

The BC Energy Plan calls for government to partner with industry, the federal government, and Geoscience BC to undertake comprehensive research in the Nechako Basin and establish new data of the resource potential. It will include active engagement of communities and the development and implementation of a comprehensive pre-tenure engagement initiative for First Nations in the region. Specific tenures and royalties will be explored to encourage investment, as well as a comprehensive Environmental Information Program to identify baseline information needs in the area through consultations with government, industry, communities and First Nations.

By increasing our oil and gas industry's competitiveness, British Columbians can continue to benefit from well-paying jobs, high quality social infrastructure and a thriving economy.

Value-Added Opportunities

To improve competitiveness, **The BC Energy Plan** calls for a review of value-added opportunities in British Columbia. This will include a thorough assessment of the potential for processing facilities and petroleum refineries as well as petrochemical industry opportunities. The Ministry of Energy, Mines and Petroleum Resources will conduct an analysis to identify and address barriers and explore incentives required to encourage investment in gas processing in British Columbia. A working group of industry and government will develop business cases and report to the Minister by January 2008 with recommendations on the viability of a new petroleum refinery and petrochemical industry and measures, if any, to encourage investment.

Oil and Gas Service Sector

British Columbia's oil and gas service sector can also help establish our province as one of the most competitive jurisdictions in North America. The service sector has grown over the past four years and with increased activity, additional summer drilling, and the security of supply, opportunities for local companies will continue. Government can help maximize the benefits derived from the service sector by:

- Promoting British Columbia's service sector to the oil and gas industry through participation at trade shows and providing information to the business community.
- Identifying areas where British Columbian companies can play a larger role, expand into other provinces, and through procurement strategies.

The government also supports the Oil and Gas Centre of Excellence at the Fort St. John Northern Lights College campus, which will provide oil and gas, related vocational, trades, career and technical programs.

Improving Oil and Gas Tenures

Government will work to improve oil and gas tenure issuance policies as well as develop new guidelines to determine areas that require special consideration prior to tenure approval by the end of 2007. This will provide clear parameters for industry regarding areas where special or enhanced management practices are required. These measures will strike the important balance between providing industry with clarity and access to resources and the desire of local government, communities, landowners, stakeholders and First Nations for input into the oil and gas development process.

Create Opportunities for Communities and First Nations

Benefits for British Columbians from the Oil and Gas Sector

The oil and gas sector offers enormous benefits to all British Columbians through enhanced energy security, tens of thousands of good, well-paying jobs and tax revenues used to help fund our hospitals and schools. However, the day-to-day impact of the sector has largely been felt on communities and First Nations in British Columbia's northeast. Community organizations, First Nations, and landowners have communicated a desire for greater input into the pace and scope of oil and gas development in British Columbia.

Together with the Oil and Gas Centre of Excellence in Fort St. John, an oil and gas technology incubator will be established, allowing entrepreneurs to develop and test new innovations.

POLICY ACTIONS

WORKING WITH COMMUNITIES AND FIRST NATIONS

- **Provide information about local oil and gas activities to local governments, First Nations, education and health service providers to inform and support the development of necessary social infrastructure.**
- **Work with First Nations to identify opportunities to participate in and benefit from oil and gas development.**
- **Support First Nations in providing cross-cultural training to agencies and industry.**
- **Improve working relationships among industry and local communities and landowners by clarifying and simplifying processes, enhancing dispute resolution methods, and offering more support and information.**
- **Examine oil and gas tenure policies and develop guidelines to determine areas that require special consideration prior to tenure approval.**

Through **The BC Energy Plan**, government intends to develop stronger relationships with those affected by oil and gas development, including communities and First Nations. The aim is to work cooperatively to maximize benefits and minimize impacts. The plan supports improved working relationships among industry, local communities and landowners by increased and improved communication to clarify and simplify processes, enhancing dispute resolution methods, and offering more support and information.

The government will also continue to improve communications with local governments and agencies. Specifically, **The BC Energy Plan** calls for efforts to provide information about increased local oil and gas activities to local governments, education and health service providers to improve their ability to make timely decisions on infrastructure, such as schools, housing, and health and recreational facilities. By providing local communities and service providers with regular reports of trends and industry activities, they can more effectively plan for growth in required services and infrastructure.

Building Better Relationships with Landowners

The BC Energy Plan: A Vision for Clean Energy Leadership also supports improved working relationships between industry, local communities and landowners and First Nations. Landowners will be notified in a more timely way of sales of oil and gas rights on private land. Plain language information materials, including standardized lease agreements will be made available to help landowners deal with subsurface tenures and activity. There will be a review of the dispute resolution process between landowners and industry by the end of 2007. The existing setback requirements, the allowed distance of a well site from a residence, school or other public place, will also be examined. These measures seek to strike the important balance between providing industry with clarity and access to resources and the desire of local government, communities, landowners, stakeholders and First Nations for input into oil and gas development.

Working in Partnership with First Nations and Communities

Government will work with First Nations communities to identify opportunities to benefit from oil and gas development. By developing a greater ability to participate in and benefit from oil and gas development, First Nations can play a much more active role in the industry. **The BC Energy Plan** also supports increasing First Nations role in the development of cross-cultural training initiatives for agencies and industry.

Conclusion

The BC Energy Plan: A Vision for Clean Energy Leadership sets the standard for proactively addressing the opportunities and challenges that lie ahead in meeting the energy needs for all the citizens of the province, now and in the future. Appendix A provides a detailed listing of the policy actions of the plan.

The BC Energy Plan will attract new investments, help develop and commercialize new technology, build partnerships with First Nations, and ensures a strong environmental focus.

British Columbia has a proud history of innovation that has resulted in 90 per cent of our power generation coming from clean sources. This plan builds on that foundation and ensures B.C. will be at the forefront of environmental and economic leadership for years to come.

APPENDIX A The BC Energy Plan: Summary of Policy Actions

ENERGY CONSERVATION AND EFFICIENCY

1. Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.
2. Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.
3. Encourage utilities to pursue cost effective and competitive demand side management opportunities.
4. Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.
5. Implement Energy Efficiency Standards for Buildings by 2010.
6. Undertake a pilot project for energy performance labeling of homes and buildings in coordination with local and federal governments, First Nations, and industry associations.
7. New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.
8. Develop an Industrial Energy Efficiency Program for British Columbia to address specific challenges faced by British Columbia's industrial sector.
9. Increase the participation of local governments in the Community Action on Energy Efficiency Program and expand the First Nations and Remote Community Clean Energy Program.

ELECTRICITY

10. Ensure self-sufficiency to meet electricity needs, including "insurance" by 2016.
11. Establish a standing offer for clean electricity projects up to 10 megawatts.
12. The BC Transmission Corporation is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.
13. Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy.
14. Ensure that the province remains consistent with North American transmission reliability standards.
15. Continue public ownership of BC Hydro and its heritage assets, and the BC Transmission Corporation.
16. Establish the existing heritage contract in perpetuity.
17. Invest in upgrading and maintaining the heritage asset power plants and the transmission lines to retain the ongoing competitive advantage these assets provide to the province.
18. All new electricity generation projects will have zero net greenhouse gas emissions.
19. Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.
20. Require zero greenhouse gas emissions from any coal thermal electricity facilities.
21. Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.
22. 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.
23. No nuclear power.
24. Review BC Utilities Commissions' role in considering social and environmental costs and benefits.
25. Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources.
26. Work with BC Hydro and parties involved to continue to improve the procurement process for electricity.
27. Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.
28. Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.

ALTERNATIVE ENERGY

29. 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.
30. Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.
31. 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.
32. Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.
33. 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.
34. Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.
35. Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.

OIL AND GAS

36. Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.
37. Establish policies and measures to reduce air emissions in coordination with the Ministry of Environment.
38. Best coalbed gas practices in North America. Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.
39. Enhance the Oil and Gas Environmental Stewardship Program, ensuring sound environmental, land and resource management.
40. Continue to work to lift the federal moratorium on offshore exploration and development and reiterate the intention to simultaneously lift the provincial moratorium.
41. Work with the federal government to ensure that offshore oil and gas resources are developed in a scientifically sound and environmentally responsible way.
42. Participate in marine and environmental planning to effectively manage marine areas and offshore oil and gas basins.
43. Develop and implement a comprehensive community engagement program to establish a framework for a benefits sharing agreement resulting from offshore oil and gas development for communities, including First Nations.
44. Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdictions in North America.
45. Enhance infrastructure to support the development of oil and gas in British Columbia and address impediments to economic development such as transportation and labour shortages.
46. Encourage the development of conventional and unconventional resources.
47. Support the growth of British Columbia's oil and gas service sector.
48. Promote exploration and development of the Interior basins with a priority focus on the Nechako Basin.
49. Encourage the development of new technologies.
50. Add value to British Columbia's oil and gas industry by assessing and promoting the development of additional gas processing facilities in the province.
51. Provide information about local oil and gas activities to local governments, education and health service providers to inform and support the development of necessary social infrastructure.
52. Work with First Nations to identify opportunities to participate in and benefit from oil and gas development.
53. Support First Nations in providing cross-cultural training to agencies and industry.
54. Improve working relationships among industry and local communities and landowners by clarifying and simplifying processes, enhancing dispute resolution methods, and offering more support and information.
55. Examine oil and gas tenure policies and develop guidelines to determine areas that require special consideration prior to tenure approval.

Energy in Action

POWERSMART
BC Hydro offers a variety of incentives to adopt energy saving technologies. Incentives such as rebates on efficient lighting or windows encourages British Columbians to improve the energy efficiency of their homes and businesses.

PROVINCIAL SALES TAX EXEMPTIONS
Tax breaks are offered for a wide variety of energy efficient items, making it easier to conserve energy. Tax concessions are in place for alternative fuel and hybrid vehicles as well as some alternative fuels. Bicycles and some bicycle parts are exempt from provincial sales tax, as are a variety of materials, such as Energy Star® qualified windows, that can make homes more energy efficient.

NET METERING
The Net Metering program offered by BC Hydro for customers with small generating facilities, allows customers to lower their environmental impact and take responsibility for their own power production. The customer is only billed for their "net consumption"; the total amount of electricity used minus the total produced. Net Metering helps to move the province towards electricity self sufficiency and expands clean electricity generation.

POWERING THE ECONOMY
The Oil and Gas sector invested $4.6 billion in B.C. in 2005 and contributed more to the provincial treasury than any other resource in 2005/06. In 2006 1,416 oil and gas wells were drilled in the province and between 2002 and 2005, summer drilling increased 242 per cent.

FRIDGE BUY-BACK PROGRAM
This program offers customers $30 in cash and no-cost pickup and disposal of an old, inefficient second fridge. If all second operating fridges in B.C. were recycled, we would save enough energy to power all the homes in the city of Chilliwack for an entire year.

LIGHTING REBATES
This program offers instant rebate coupons for the retail purchase of Energy Star® light fixtures and Energy Star® CFLs (Compact Fluorescent Lights).

WINDOWS REBATE
The Windows Rebate Program offers rebates for the installation of Energy Star® windows in new, renovated or upgraded single-family homes, duplexes, townhouses or apartments.

PRODUCT INCENTIVE PROGRAM
The Product Incentive Program provides financial incentives to organizations which replace inefficient products with energy efficient technologies or add on products to existing systems to make them more efficient.

HIGH-PERFORMANCE BUILDING PROGRAM FOR LARGE COMMERCIAL BUILDINGS
Financial incentives, resources, and technical assistance are available to help qualified projects identify energy saving strategies early in the design process; evaluate alternative design options and make a business case for the high-performance design; and, offset the incremental costs, if any, of the energy-efficient measures in the high-performance design.

HIGH-PERFORMANCE BUILDING PROGRAM FOR SMALL TO MEDIUM COMMERCIAL BUILDINGS
Incentives and tools are offered to help owners and their design teams create and install more effective and energy-efficient lighting in new commercial development projects.

NEW HOME PROGRAM
Builders and developers are encouraged to build energy efficient homes by offering financial incentives and Power Smart branding for homes that achieve energy efficient ratings.

ANALYZE MY HOME
BC Hydro offers an online tool that provides a free, personalized breakdown of a customer's home energy use and recommendations on where improvements can be made to lower consumption.

CONSERVATION RESEARCH INITIATIVE
A 12-month study in six communities that examines how adjusting the price of electricity at different times of day influences energy use by residential customers, and how individual British Columbians can make a difference in conserving power in their homes and help meet the growing demand for electricity in B.C.

THE GREEN BUILDINGS PROGRAM
Provides tools and resources to support school districts, universities, colleges, and health authorities to improve the energy efficiency of their buildings across the province.

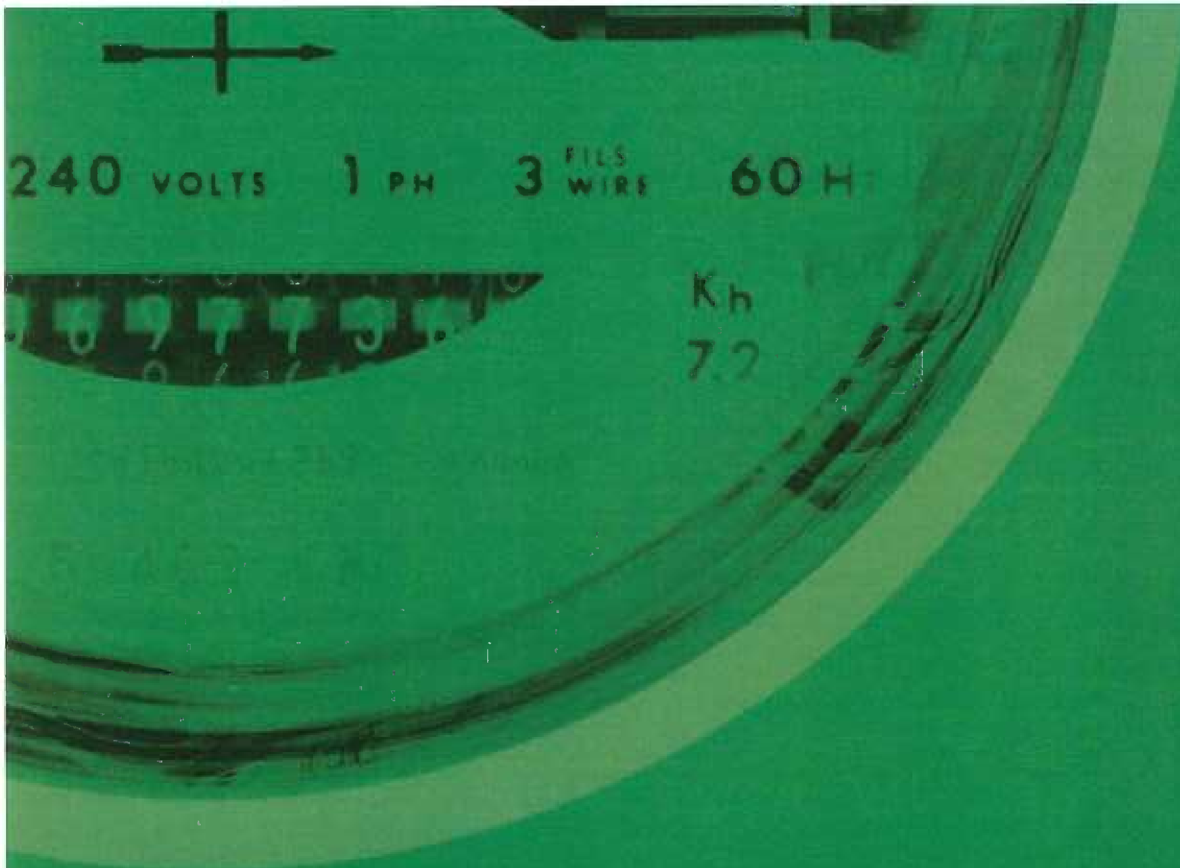
ATTRACTING WORKERS
The Ministry of Energy, Mines and Petroleum Resources hosts job fairs across B.C. to attract workers to the highly lucrative oil and gas sector. Job fairs were held in 14 communities in 2005 and 16 communities in 2006 attracting thousands of people and resulting in hundreds of job offers. Centre of Excellence Government is partnering with industry and the Northern Lights College in Fort St. John to build a centre for oil and gas excellence, more than doubling the number of students training for jobs in the oil and gas industry.

CENTRE OF EXCELLENCE
Government is partnering with industry and the Northern Lights College in Fort St. John to build a centre for oil and gas excellence, more than doubling the number of students training for jobs in the oil and gas industry.

100,000 SOLAR ROOFS FOR B.C.
The Ministers of Environment, and Energy, Mines and Petroleum Resources are sponsoring the development of a plan that will see the aggressive adoption of solar technology in B.C. The goal of the project is to see the installation of solar roofs and walls for hot water heating and photovoltaic electricity generation on 100,000 buildings around B.C.

PARTNERING FOR SUCCESS
Since 2003, the Province of B.C. has partnered in the construction of $158 million in new oil and gas road and pipeline infrastructure. The Sierra Yoyo Desan Road public private partnership improved the road allowing year round drilling activity in the Greater Sierra natural gas play. The project was recognized with the Gold Award for Innovation and Excellence from the Canadian Council for Public Private Partnerships in 2004.

ENERGY EFFICIENT BUILDINGS: A PLAN FOR BC
This strategy will lower energy costs for new and existing buildings by $127 million in 2010 and $474 million in 2020, and reduce greenhouse gas emissions by 2.3 million tonnes in 2020. The Province is implementing ten policy and market measures in partnership with the building industry, energy consumer groups, utilities, non-governmental organizations, and the federal government.



For more information on
The BC Energy Plan:
A Vision for Clean Energy Leadership, contact:

Ministry of Energy, Mines and Petroleum Resources
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Victoria, BC V8W 9N3

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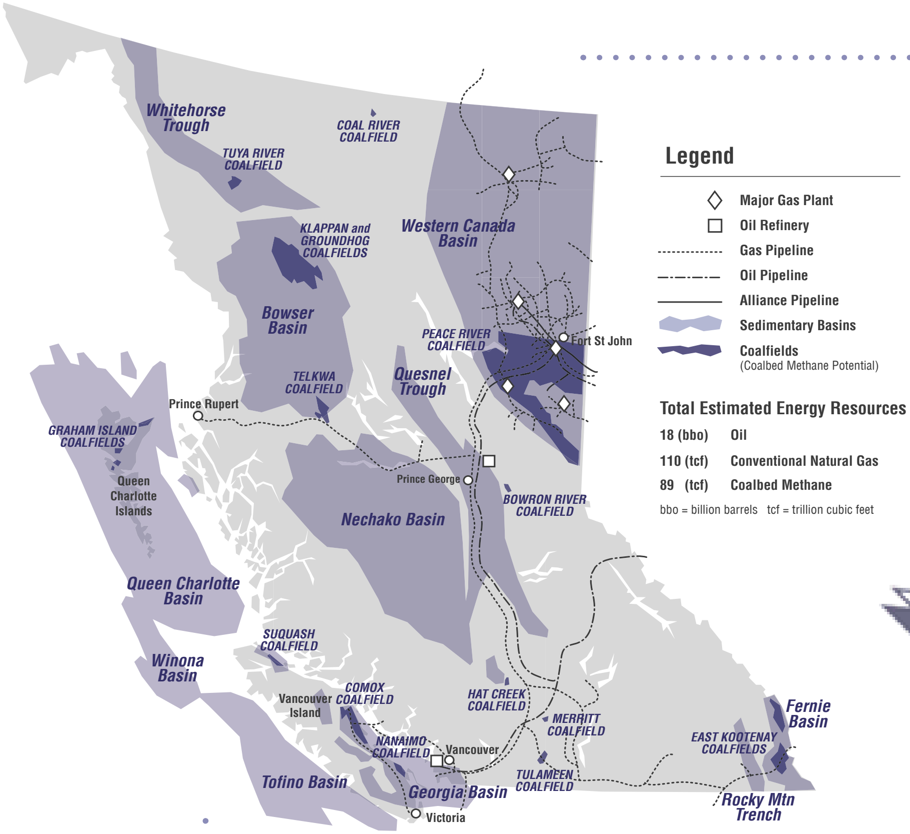
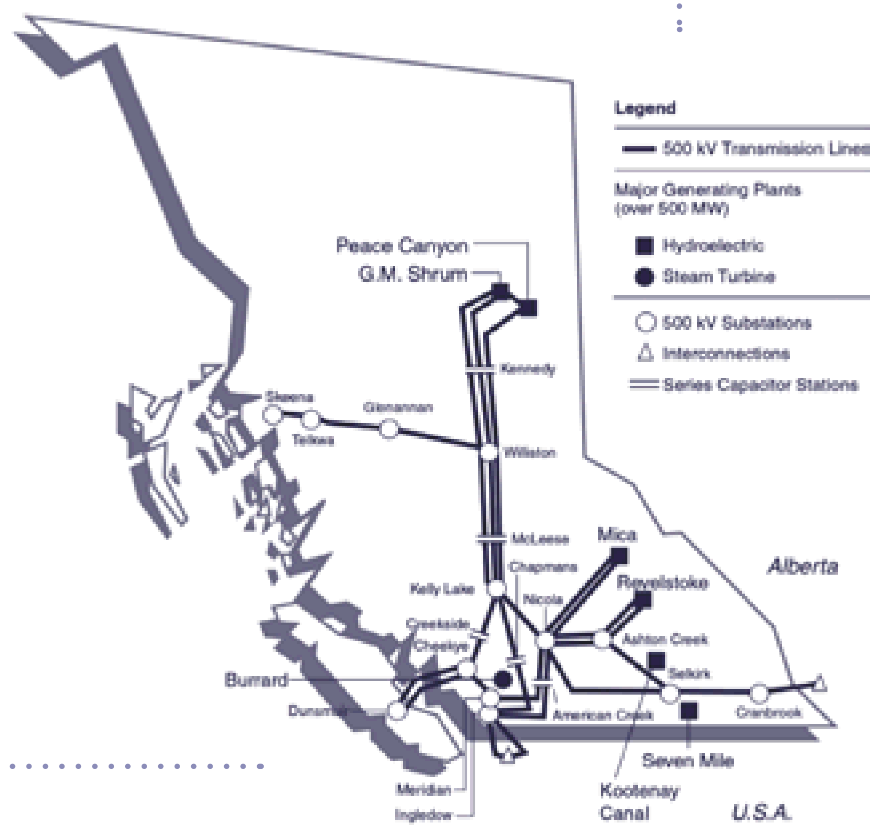
British Columbia
The Best Place on Earth

Ministry of
Energy, Mines and
Petroleum Resources

ENERGY FOR OUR FUTURE: A PLAN FOR BC

BRITISH COLUMBIA'S ENERGY RESOURCES





ENERGY FOR OUR FUTURE: A PLAN FOR BC

Low electricity rates and public ownership of BC Hydro

Secure, reliable supply

More private sector opportunities

Environmental responsibility and no nuclear power sources

MESSAGE FROM THE MINISTER

Energy is a critical part of our daily lives, powering our households, communities and businesses. In B.C., we have abundant, diverse energy resources, including hydroelectricity, oil, gas, coal, coalbed methane and a variety of clean, alternative sources. The time has come to harness their enormous potential to meet our energy needs and generate renewed economic growth and prosperity for all British Columbians.

Energy for Our Future: A Plan for BC is designed to achieve our goal in an environmentally responsible way. It is built around four cornerstones to maximize benefits for British Columbians well into the future. The cornerstones deliver low electricity prices and public ownership of BC Hydro; a secure, reliable supply of energy; more private sector opportunities; and environmental responsibility with a guarantee of no nuclear generation in B.C.

Ultimately, the plan reflects our government's vision of the future for both the energy sector and the province as a whole -- a prosperous future, lively with opportunities for all British Columbians; a dynamic future, in which British Columbia is opened up to its full potential; a certain future, in which British Columbians can move forward with confidence, knowing they live and work in the best place on earth.

Richard Neufeld

RNeufeld

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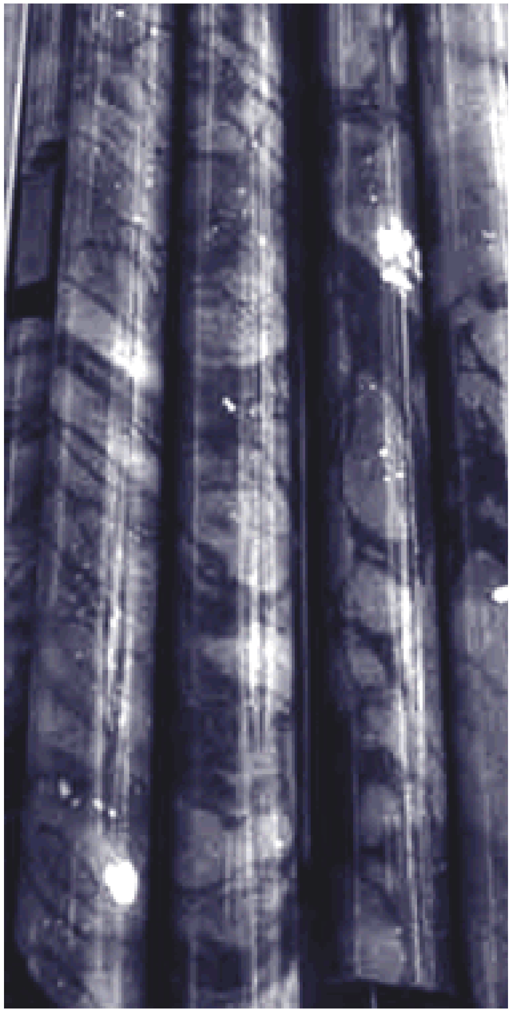
EXECUTIVE SUMMARY



ENERGY FACT

An average household in BC Hydro's service area uses about 10,000 kWh of electricity per year.

After five decades of dramatic change, British Columbia's energy sector faces new challenges and opportunities.

Our natural gas industry has seen production more than double in the past 10 years. In North America and abroad, electric power markets are being reformed to make them more competitive. With these and other changes, the B.C. energy sector is poised for new investment, increased trade and regional economic growth. To realize its potential, the sector needs an updated plan that will guide its further development over the coming decade.

The purpose of this energy policy, *Energy for Our Future: A Plan for BC,* is to build on B.C.'s strengths to help revitalize the provincial economy and create jobs in an environmentally responsible way.

Energy policy and economic policy are inextricably linked. The Government of British Columbia is committed to restoring a strong and vibrant economy with job creation in all regions of the province. At the same time, a healthy environment is recognized as one of our enduring natural assets. This plan builds on B.C.'s advantages, in particular our abundant energy resources and low electricity prices, with improvements to strengthen the energy sector and provide sustainable economic benefits.

BACKGROUND

Energy drives the economy and makes our modern lifestyle possible.

British Columbians depend on energy to fuel their cars, run their appliances, equipment and industrial plants, and light and heat their homes, communities and businesses. Without a reliable and reasonably priced supply of energy, important industries such as forestry, chemicals, mining and high technology cannot thrive in world markets. The production and delivery of energy is itself a source of economic activity, employing about 35,000 people in 2001, and generating about $2.4 billion in provincial revenues that support health care and other programs. While energy production is focused in the Northeast, Southeast, and on the Columbia River, development opportunities offer the prospect of new investment and jobs throughout the province.

B.C. is becoming increasingly integrated with North American energy markets.

Historically, a strong export orientation has allowed B.C. energy suppliers to take advantage of economies of scale to develop energy resources at lower cost, for the benefit of domestic consumers. Today, B.C. exports two-thirds of the energy it produces, including virtually all of our coal and more than half of our natural gas production. Most of the refined petroleum products (e.g., gasoline and home heating oil) we use comes from Alberta, while imported electricity helps meet provincial needs during periods of below-average water inflows into our hydroelectric reservoirs. The net revenues from energy trade contribute to further energy investment and low electricity rates in the province. Energy exports also play a role in continental energy security by providing clean, reliable energy for consumers in the United States and Alberta.

The province enjoys a number of key energy strengths.

B.C. has extensive reserves of coal, oil, natural gas as well as considerable undeveloped resources of coalbed methane (the gas found in coal seams), hydroelectric and alternative energy, such as small hydro, wood residue, ethanol/biofuels, wind and tidal power. In addition, BC Hydro estimates that in the order of 10 percent of electricity demand could be economically saved by 2015, through greater conservation and efficient energy use. B.C. already benefits from a highly developed energy supply network, with substantial production of coal, natural gas, oil and hydroelectricity. Electricity rates among the lowest in North America are the legacy of large-scale public investment on the Peace and Columbia rivers that was undertaken a generation ago.

CHALLENGES AND OPPORTUNITIES

New energy supplies are required to meet growing demand and support renewed economic growth.

More energy is needed to fuel the growth that will restore B.C. to its position as an economic leader within Canada. Rising energy demands and aging facilities call for major financial investment in plant upgrades and new energy production and delivery facilities. This, in turn, requires better access to energy resources and the timely, cost-effective development of new supplies. Unless domestic energy sources are developed, British Columbians could find themselves increasingly dependent on imports and vulnerable to price swings. The government, faced with competing fiscal priorities, is looking to the private sector for much-needed energy development.

We have to keep electricity rates down to maintain B.C.'s economic advantage.

BC Hydro rates, frozen since 1996, have not changed or undergone a public review since 1993. With electricity costs rising, the rate freeze must end and BC Hydro rates must be independently regulated by the BC Utilities Commission to keep rate changes to a minimum and remove political interference. At the same time, B.C. will need to adapt to evolving market rules in the United States, if we want to continue earning the export revenues that contribute to our low power rates. These rates give B.C. industry an economic advantage in global markets.

Energy development and use must continue to be environmentally responsible.

A clean, natural environment and energy-efficient facilities and equipment are also important to ensuring our long-term economic advantage. British Columbians are concerned about the environmental impacts from energy development and use. Energy-saving activity that reduces demand and defers the need for new supply is one of the most cost effective strategies for controlling impacts on provincial airsheds and watersheds. Low electricity rates, however, provide a poor price signal for consumers to conserve and invest in energy efficiency. In general, unclear environmental standards and inefficient regulatory processes have hindered environmentally responsible energy development in the province.

The energy sector is well positioned to generate new investment, increased trade and economic growth.

B.C.'s natural resources, talent and homegrown technology offer many diverse opportunities for meeting the changing energy needs of provincial consumers. Efforts are underway to make domestic electricity service even more reliable in support of technology industries and the new information economy. The outlook for increased energy trade is favourable, given growing US demands, especially for natural gas in power generation. Here at home, the private sector has demonstrated its ability to develop the smaller-scale generation (e.g., small hydro and efficient natural gas turbines) that can locate close to load, avoid transmission losses and infrastructure costs, and provide regional economic benefits. To enable investment in the oil and gas sector, land use and pre-tenure planning, road upgrading and cooperation with First Nations are improving access to resources for exploration and development in the Northeast.

Low cost hydroelectricity and efficient regulation can help preserve our electricity rate advantage.

While other jurisdictions struggle under large power debts and high electricity prices, B.C. benefits from W.A.C. Bennett's vision of the hydroelectric system developed in the 1960s and 1970s on the Peace and Columbia rivers. These heritage assets have an inherent value given by the difference between their current cost of production and what it would cost to replace this power in the marketplace. There are ways to secure the benefits of existing low-cost generation for B.C. consumers. Furthermore, performance-based regulation and negotiated settlements can be used to regulate BC Hydro rates efficiently and encourage cost savings, so that future rate changes will be minimized.

Aggressive energy saving and alternative energy development can better manage environmental impacts.

For more than a decade, the province's energy utilities, private energy service companies and individual consumers have accumulated expertise in reducing energy use through conservation and energy efficiency. It is possible to design electricity rates to give consumers the right signals for this energy saving activity. We can also develop our alternative energy resources to provide power that is less harmful to the environment than conventional (large hydro, coal-fired and natural gas-fired) generation. Other countries have adopted portfolio standards requiring a portion of electricity supply to come from technologies that have a low impact on the environment.

The energy sector is well positioned to generate new investment, increased trade and economic growth.

SOLUTIONS

Low electricity rates and public ownership of BC Hydro

Secure, reliable supply

More private sector opportunities

Environmental responsibility and no nuclear power sources

The four cornerstones of *Energy for Our Future: A Plan for BC* are low electricity rates and public ownership of BC Hydro; secure, reliable supply; more private sector opportunities; and environmental responsibility and no nuclear power sources.

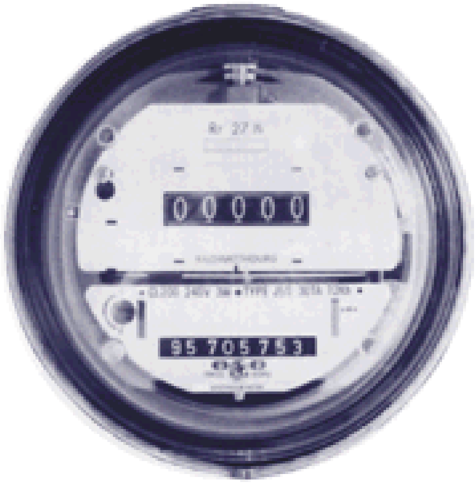
B.C.'s low-cost electricity will remain an important economic advantage during the next decade. Stable and dependable energy supplies will be vital not only to sustain our other resource industries, but also to grow the technology sector. Private developers, including independent power producers, will be key partners in the province's energy future. We will build on one of North America's best environmental records with efficient regulation that holds energy producers and consumers accountable for their impacts.

Low electricity rates will be assured by entrenching the benefits of publicly owned assets, independently regulating BC Hydro rates and outsourcing services where economic.

BC Hydro ratepayers will benefit from a legislated heritage contract that locks in the value of existing low-cost generation (heritage energy), and from the continued use of trading revenues to supplement domestic revenues. The BC Utilities Commission will conduct an inquiry and recommend the terms and conditions of the heritage contract legislation. To benefit ratepayers and taxpayers alike, public ownership of BC Hydro generation, transmission and distibution assets will continue. The delivery of services will be outsourced where costs can be reduced for consumers while maintaining quality of service. The rate freeze will end on March 31, 2003 and the BC Utilities Commission will hold a revenue requirement hearing by the end of 2003/04 to review BC Hydro costs. Future rate changes will then be determined using performance-based regulation and negotiated settlements.

To promote secure and dependable energy, reliability standards will be maintained, new supplies will be developed and the BC Utilities Commission will be strengthened.

BC Hydro will continue to establish separate lines of business for generation, transmission and distribution. Distribution will acquire new power on a least-cost basis, subject to regulatory



Actions that support low electricity rates and public ownership of BC Hydro:

#1	A legislated heritage contract will preserve the benefits of BC Hydro's existing generation.
#2	BC Hydro ratepayers will continue to benefit from electricity trade.
#3	Public ownership of BC Hydro generation, transmission and distribution assets will continue.
#4	BC Hydro will outsource the delivery of services where costs can be reduced for electricity consumers while maintaining quality of service.
#5	The BC Utilities Commission will once again regulate BC Hydro rates.
#9	Electricity distributors will acquire new supply on a least-cost basis, with regulatory oversight by the BC Utilities Commission.
#13	The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.
#15	The BC Hydro Transmission Corporation will improve access to the transmission system and enable IPP participation in US wholesale markets.
#16	The BC Utilities Commission will determine the terms and rates for this new transmission entity.
#21	New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.
#22	The Province will update and expand its Energy Efficiency Act, and will work with the building industry, governments and others to improve energy efficiency in new and existing buildings.
#23	The Utilities Commission Act will be amended to remove a disincentive for energy distributors to invest in conservation and energy efficiency.

oversight. As part of this process, it will obtain heritage energy from the generation business at a rate to be determined by the BC Utilities Commission. The commission's structure and mandate will be strengthened to support the re-regulation of BC Hydro and the efficient regulation of other utilities.

To encourage new resources, the government will develop requirements for exploring and developing coalbed methane and other unconventional hydrocarbon resources. In general, energy reliability will be maintained and improved through well-functioning natural gas markets and coordinated electricity planning.

A dedicated provincial offshore oil and gas team will develop a provincial position, work with the federal government and move effectively toward development of offshore oil and gas resources.

Before offshore development can proceed, further issues need to be resolved such as an agreement between the federal and provincial governments on an overall management regime, including regulatory, royalty and environmental requirements. The Province will also need to work with coastal communities and First Nations to ensure that benefits accrue to the areas where activity occurs.

A dedicated provincial offshore oil and gas team will develop a provincial position, work with the federal government and move effectively toward development of the offshore oil and gas resources.

Actions that support secure reliable supply:

#1	A legislated heritage contract will preserve the benefits of BC Hydro's existing generation.
#6	The Vancouver Island Generation Project will be reviewed to determine if it is the most cost-effective means to reliably meet Island power needs.
#7	High reliability and energy security will be maintained through well-functioning natural gas markets and coordinated electricity planning.
#8	BC Hydro distribution will operate as a separate line of business from generation.
#9	Electricity distributors will acquire new supply on a least-cost basis, with regulatory oversight by the BC Utilities Commission.
#10	Development of coalbed methane and other unconventional resources will be encouraged to provide a new source of energy supply and opportunities for regional economic growth.
#11	The Ministry of Energy and Mines will establish a dedicated provincial offshore oil and gas team to develop a provincial position, work with the federal government and move effectively toward development of the offshore resources.
#12	The structure of the BC Utilities Commission, and its mandate in regulating BC Hydro and other energy distributors, will be strengthened.
#13	The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.
#15	The BC Hydro Transmission Corporation will improve access to the transmission system and enable IPP participation in US wholesale markets.
#18	Pre-tenure and land use planning, as well as northern road improvements, are improving access to oil and gas resources.
#19	Natural gas marketers will be allowed to sell directly to small volume customers, and will be licensed to provide consumer protection.
#21	New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.
#22	The Province will update and expand its Energy Efficiency Act, and will work with the building industry, governments and others to improve energy efficiency in new and existing buildings.
#23	The Utilities Commission Act will be amended to remove a disincentive for energy distributors to invest in conservation and energy efficiency.

ENERGY FACT

Industry invested $5.1 billion in B.C.'s petroleum and natural gas resources, a 46 % increase over 2000.

To increase opportunities for the private sector, independent power will be developed and ongoing support will be provided for the oil and gas industry.

Independent power producers (IPPs) will develop new generation, with BC Hydro's role limited to undertaking efficiency improvements at existing facilities. A separate entity, BC Hydro Transmission Corporation, will operate BC Hydro's publicly owned transmission system, to ensure fair access for all generators. Under a new BC Hydro rate structure, IPPs will be able to serve a portion or all of the electricity needs of large customers. Similarly, natural gas marketers will be free to sell directly to residential and small commercial natural gas consumers. These and other ongoing government initiatives in the oil and gas sector (e.g., royalty reform, pre-tenure planning and public-private partnerships for road upgrades) will support private investment and economic opportunities across the province.

Environmental responsibility will be assured through a clean energy goal, new price signals for conservation, clear emission standards and other strategies.

Electricity distributors will pursue a voluntary goal to purchase at least 50 percent of their new power supply from BC Clean resources that are renewable or result in a net environmental improvement over existing generation. New rate structures (stepped and time-of-use rates) will give better signals for energy saving activity. The government will also expand and update its Energy Efficiency Act and regulations, and will change utility regulatory practices to remove a disincentive to energy efficiency investments by utilities. The Ministries of Energy and Mines and Water, Land and Air Protection are working together on strategies to address climate change and air quality in sensitive airsheds. In other areas, provincial processes for environmental assessment, water licensing and waste permitting are being streamlined. To allow a fair evaluation of

The publicly owned BC Hydro Transmission Corporation will operate BC Hydro's transmission system to ensure fair access for all generators

Actions that support more private sector opportunities:

#4	BC Hydro will outsource the delivery of services where costs can be reduced for electricity consumers while maintaining quality of service.
#9	Electricity distributors will acquire new supply on a least-cost basis, with regulatory oversight by the BC Utilities Commission.
#10	Development of coalbed methane and other unconventional resources will be encouraged to provide a new source of energy supply and opportunities for regional economic growth.
#11	The Ministry of Energy and Mines will establish a dedicated provincial offshore oil and gas team to develop a provincial position, work with the federal government and move effectively toward development of offshore resources.
#13	The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.
#14	Under new rates, large electricity consumers will be able to choose a supplier other than the local distributor.
#15	The BC Hydro Transmission Corporation will improve access to the transmission system and enable IPP participation in US wholesale markets.
#17	The Ministry of Energy and Mines will provide support for continued industry investment in natural gas production over the next 10 years.
#18	Pre-tenure and land use planning, as well as northern road improvements, are improving access to oil and gas resources.
#19	Natural gas marketers will be allowed to sell directly to small volume customers, and will be licensed to provide consumer protection.
#25	Provincial processes for environmental assessment, water licensing and waste permitting are being streamlined.
#26	To allow for a fair evaluation of coal-fired electricity projects, final emission standards will be adopted for coal-fired power plants.

the role of coal-fired generation in B.C.'s electricity future, the Province will adopt emission guidelines for coal-fired power plants that will allow B.C. to compete for investment with neighbouring jurisdictions.

Energy consumers, private investors and B.C. communities will all benefit from the plan, as it is implemented over the next two years.

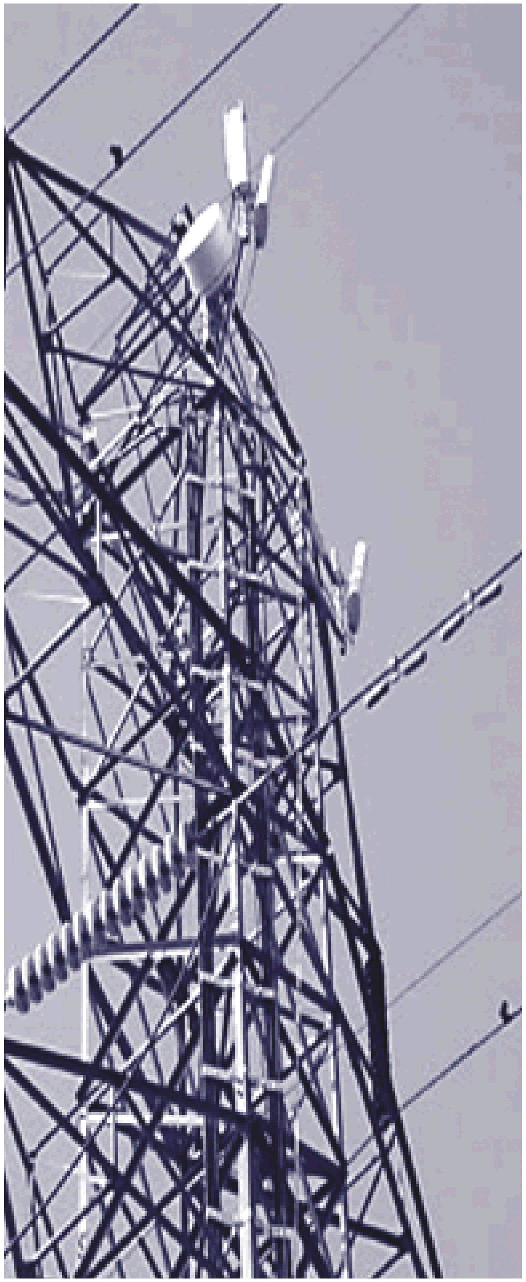
Energy for Our Future: A Plan for BC will be fully implemented by 2004. B.C. consumers will enjoy low electricity rates, greater choice among energy suppliers and potential savings in their electricity and natural gas bills. Private investors will be able to better access and develop new energy resources, while communities will reap the benefits of economic development and local environmental improvement. Taken together, the plan's 26 actions will make the energy sector more resilient and flexible for future changes that will serve British Columbians' interests.

Energy for Our Future: A Plan for BC will be fully implemented by 2004.

Actions that support environmental responsibility:

#13	The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.
#20	Electricity distributors will pursue a voluntary goal to acquire 50 percent of new supply from BC Clean Electricity over the next 10 years.
#21	New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.
#22	The Province will update and expand its Energy Efficiency Act, and will work with the building industry, governments and others to improve energy efficiency in new and existing buildings.
#23	The Utilities Commission Act will be amended to remove a disincentive for energy distributors to invest in conservation and energy efficiency.
#24	The government is developing strategies to manage B.C.'s greenhouse gas emissions and air quality in threatened airsheds.
#25	Provincial processes for environmental assessment, water licensing and waste permitting are being streamlined.
#26	To allow for a fair evaluation of coal-fired electricity projects, final emission standards will be adopted for coal-fired power plants.

INTRODUCTION



British Columbia's energy sector encompasses all the people, facilities and equipment involved in energy production, delivery and consumption. The sector has been transformed over the past half century. Today, new challenges and opportunities call for an updated energy policy that will support renewed economic growth in the province.

A LOOK BACK

B.C.'s energy sector has changed dramatically during the past 50 years, with public investment in electric power and private development of oil, natural gas and coal resources.

In the early 1950s, energy and the provincial economy looked very different. The energy sector was focused on serving a small domestic resource economy. Energy was supplied by localized monopolies and power rates were relatively high. The next four decades saw tremendous change, from large-scale hydroelectric development on the Peace and Columbia rivers and the construction of major pipelines to expanding oil and gas production in the Northeast, to deregulation of natural gas markets and the emergence of independent power producers. Today, B.C. enjoys a more diversified economy, an extensive network of energy supply facilities, low electricity rates and the benefits of a more competitive, export-oriented energy sector.

Provincial energy policy has evolved along with these changes.

In 1980, the Province of British Columbia released its first energy policy. An *Energy Secure British Columbia* sought to manage energy resources for a secure supply, reduce oil imports and conserve resources. Direct government intervention in energy markets, from setting natural gas prices to building hydroelectric facilities, was the dominant policy direction. At the same time, the BC Utilities Commission was created to provide independent oversight of energy utilities.

The 1980s witnessed a shift from government intervention to market determination of oil and gas prices. In 1985, natural gas markets were opened up and the federal government relinquished control of petroleum markets. A second policy statement, *New Directions for the 1990s*, appeared in 1990, with two new priorities - efficient energy and clean energy; and two left over from the previous decade - secure energy and energy for the economy. The objectives of this policy were to make markets more competitive, send better price signals to consumers, encourage cleaner fuels and energy efficiency and strengthen environmental standards.

Two investigations in the mid-1990s looked at reforming the B.C. electricity market to make it more competitive.

At the request of Lieutenant Governor in Council, the BC Utilities Commission undertook an Electricity Market Structure Review in 1994/95. This review found that the driving forces for electricity reform, in particular high prices, did not exist in B.C. The Commission's report recommended that B.C. move forward with increased competition at the wholesale level (e.g., private power producers selling to BC Hydro) and real-time pricing, which allows large power users to obtain their additional electricity requirements at market prices.[1]

In 1997, a BC Task Force on Electricity Reform was unable to agree on the components of market reform for the province. The head of the task force, Dr. Mark Jaccard, subsequently presented his own proposal for phased electricity reform.[2] Dr. Jaccard's suggestions included establishing an independent grid operator to improve (wholesale) access for competitive suppliers to BC Hydro's transmission system, allowing non-utility suppliers to sell directly to industrial customers (limited retail access), and setting a portfolio standard to require that a percentage of power generation come from environmentally desirable technologies.

Since the release of these reports, some of their suggested reforms have been implemented, including wholesale transmission access, real-time pricing for large BC Hydro customers and retail access for Aquila Networks Canada (formerly West Kootenay Power) industrial customers. Others, such as the independent grid operator and portfolio standard, were not acted upon.

In August 2001, Premier Gordon Campbell commissioned the Task Force on Energy Policy to provide recommendations to government.

After producing an interim report[3] in November 2001, the task force consulted with stakeholders and the public. A final report[4] was submitted to the Minister of Energy and Mines on March 15, 2002, with 46 recommendations in the areas of conservation and energy efficiency, alternative energy, electricity, oil and natural gas, coal and regulation. These recommendations support a series of policy directions that include developing new energy supplies, making markets more competitive, reforming the electricity industry, ensuring sound environmental decisions and harmonizing government regulations. Appendix 1 lists the recommendations in full and provides a government response in each case.

THE PATH FORWARD

B.C.'s new *Energy for Our Future: A Plan for BC* builds on these past efforts with a strategic path for the energy sector.

Energy policy and economic policy are inextricably linked. The government is committed to restoring a strong and vibrant provincial economy with employment opportunities for British Columbians. At the same time, a healthy environment is recognized as one of B.C.'s important natural assets. The purpose of this new policy is therefore to build on the province's energy strengths, in particular our abundant natural resources and low electricity prices, to help revitalize the economy and create jobs in an environmentally responsible way.

There are four cornerstones of B.C.'s plan:

Low electricity rates and public ownership of BC Hydro. Low-cost electricity will be an enduring economic advantage during the next decade. Legislation will entrench the benefits of our publicly owned hydroelectric power assets, and will ensure efficient regulation to keep rates low, maintain industry competitiveness, and support economic growth.

Secure, reliable supply. Stable and dependable energy supplies are increasingly vital in the move to an information economy. To sustain our resource industries and expand the technology sector, energy reliability will be improved and energy markets will be diversified, with more sources of supply, greater competition in electricity generation and enhanced customer choice.

More private sector opportunities. The private sector will be a key partner in the province's energy future. New investment in private power production and continued high activity levels in the oil and gas industry will be critical to realize our full potential as a leading energy supplier in North America.

Environmental responsibility and no nuclear power sources. B.C. has a history of environmentally responsible energy development and one of the best environmental records on the continent. We continue to reject nuclear power and will build on our clean energy strengths with incentives for alternative energy development, new rate signals to encourage energy saving and aggressive strategies for conservation and energy efficiency.

This plan outlines actions the government will take, or has already initiated, to achieve these four objectives.

The plan begins by providing some background on energy production and use in B.C. It then describes several challenges and opportunities currently facing the energy sector. Next, a series of policy actions are outlined in support of the four cornerstones above. The statement ends with a summary of the implications of these policies for consumers, producers, and other participants in the sector. Readers should note that the plan does not address energy use in transportation, which is being dealt with separately through the BC Climate Change Plan and other initiatives underway.

1 British Columbia Utilities Commission, *The British Columbia Electricity Market Review: Report and Recommendations to the Lieutenant Governor in Council*, September 1995.

2 Dr. Mark Jaccard, *Reforming British Columbia's Electricity Market: A Way Forward*, Final Report of the British Columbia Task Force on Electricity Market Reform, January 1998.

3 Task Force on Energy Policy, *Strategic Considerations for a New British Columbia Energy Policy, Interim Report*, November 2001.

4 Task Force on Energy Policy, *Strategic Considerations for a New British Columbia Energy Policy, Final Report*, March 2002.

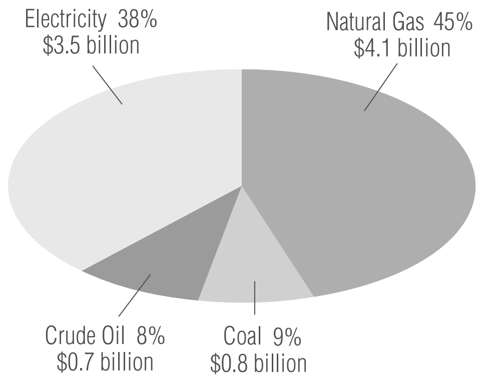
ENERGY FACT

A typical large office building (20-25 stories) will consume 3.5 GWh of electricity per year, equal to the consumption of 350 households.

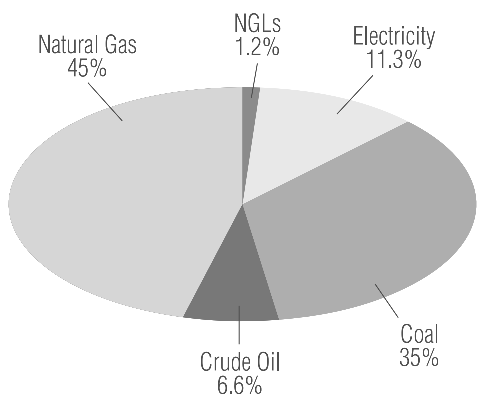
BACKGROUND

VALUE OF BC ENERGY PRODUCTION - 2000

$9.1 Billion total



BC PRIMARY ENERGY PRODUCTION - 2000



Energy is a necessity for and a key driver of B.C.'s economy and quality of life. It contributes to the international trade that is responsible for most of the economic benefits in which we all share. Energy markets continue to evolve with pressures for change in the electricity industry. Appendix 2 provides an overview of the B.C. energy sector.

THE IMPORTANCE OF ENERGY

Energy fuels our daily lives.

British Columbians rely on energy to power their cars, run their appliances, equipment and industrial plants, and light and heat their homes, communities and businesses. Perhaps nowhere is the importance of energy more evident than in the case of electric power. Whereas 20 years ago the average home had relatively few appliances, today it has a computer, two TVs, a dishwasher, microwave oven, VCR and DVD player, among other items. New technologies such as high resolution TVs can consume significantly more energy. Likewise, the typical office is now equipped with computers, photocopiers, fax machines and other electricity-using equipment.

Energy also drives the provincial economy.

Energy is a significant input into the production of other resource commodities. The energy-intensive sectors of forest products, mining, refining, and chemicals together make up 70 percent of provincial exports. These sectors, facing tough competition in the global marketplace, must control costs and increase efficiency and productivity to maintain their economic advantage.

Access to reliable, low-cost energy is also important for attracting and developing the technology sector in B.C. Technology firms are particularly dependent on a continuous supply of electricity, as shown by California's recent energy crisis. The Silicon Valley Manufacturing Group has estimated that its almost 200 members lost more than $100 million during one day of rolling blackouts in June 2000.[5]

The energy sector itself is a major source of economic activity.

The sector as a whole (electricity, natural gas, oil and coal) employs about 35,000 people. Energy accounts for about four percent of provincial gross domestic product, the value of our economy's output.

Revenues to energy industries totaled $9.1 billion in 2000, and direct revenues to government exceeded $3 billion. The oil and gas industry, at $1.8 billion in 2000, is B.C.'s largest source of natural resource revenues that help to fund health care and education. In 2001/02, lower prices resulted in a decline of $650 million to the Province. Dividends, water rentals, and taxes from BC Hydro yield in the order of $700 million annually. Aside from its employment and revenue benefits, energy contributes to regional development, primarily in the Northeast and Southeast, but increasingly with opportunities across the province.

THE ROLE OF TRADE

An export orientation has allowed energy resources to be developed at lower cost for British Columbians.

British Columbia currently exports two-thirds of the energy it produces. Much of today's network of energy production and delivery facilities would not exist had resources been developed only to serve provincial consumers. Examples include an extensive hydroelectric system on the Peace and Columbia rivers, the Duke Energy (formerly Westcoast Energy) pipeline bringing natural gas to Vancouver, and natural gas drilling in the Northeast. A strong export orientation has allowed the energy sector to take advantage of economies of scale and develop resources at lower cost. This, in turn, has resulted in reliable and reasonably priced energy service for B.C. consumers.

Electricity trade helps ensure low power rates and reliability for domestic consumers.

The province's flexible hydroelectric system, with its large reservoirs for storing water, enables highly beneficial trade in electricity. BC Hydro earns revenues by importing electricity when market prices are low and exporting electricity when prices are high, while at all times satisfying domestic power needs. The net revenues from this trade help keep provincial rates low and stable.

Imports also help meet electricity requirements during times of reduced water inflows into B.C. reservoirs. BC Hydro can earn significant trading income even in low water years, when the province is a net importer, because of the flexibility of our large hydroelectric and reservoir systems. Net trading revenue averaged around $100 million annually during the 1990s.

Our clean energy exports contribute to continental energy security.

B.C.'s hydro-based electricity exports offer a source of clean, reliable power for consumers in the United States and Alberta. In US markets, our natural gas displaces oil and coal used to generate electricity. With growing North American demand, especially for natural gas used in power plants, B.C. has a key role to play in supporting continental energy security. Continued integration with regional power markets will provide better access to reliable, low-cost electricity for our export customers and provincial consumers alike.

B.C.'S ENERGY STRENGTHS

We have extensive undeveloped energy resources for new supply and a significant potential to further reduce energy use.

Discovered reserves of natural gas are sufficient to meet domestic and export needs for the next decade. Undiscovered reserves of natural gas, including coalbed methane, could add decades of new supply, but will require further exploration to be realized. Coal resources, if used for electricity production at B.C.'s current electricity consumption rate, could last well over a century.

While there are considerable resources remaining for large hydroelectric development, many are on protected rivers. The potential for other renewable electricity, including small hydro, wood residue, wind and tidal energy, is growing over time as technologies improve and costs decline. In total, new conventional (available large hydro, natural gas-fired and coal-fired) and alternative energy resources are currently estimated at more than double existing generating capacity. In addition, BC Hydro estimates that 10 percent of total electricity demand could be economically saved by 2015, through increased conservation and energy efficiency.

Biofuel technologies are under development to convert plant material such as wood waste into ethanol and other transportation fuels. B.C. has enough wood residue to produce over 300 million litres of ethanol annually. Ethanol is blended with gasoline and diesel fuel to add oxygenation, extend conventional fuel supplies and reduce transportation-related emissions.

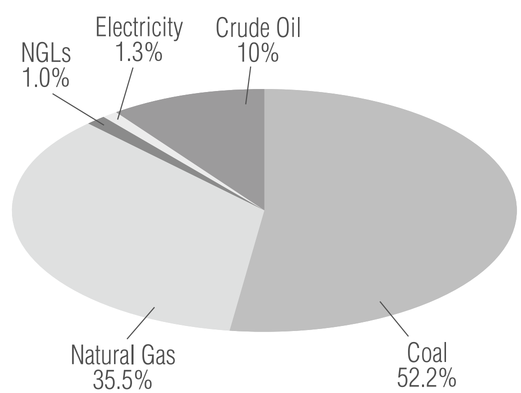
A diverse, reliable energy supply network has evolved in the province.

The energy sector is large and diverse. It comprises substantial production of hydroelectricity, natural gas, coal and oil. Highly developed systems of pipelines and power lines deliver energy to domestic and export consumers. B.C. companies are also pursuing leading-edge alternative technologies, such as fuel cells, and innovative ventures in wind, wave and solar power.

Electric utilities and natural gas suppliers have a proven record of providing reliable energy for both the provincial and export markets. Natural gas suppliers ensure reliability by upgrading production facilities and pipeline capacity to meet growing demand. Electricity suppliers do so by

Electricity trade helps ensure low power rates and reliability for domestic consumers.

BC ENERGY EXPORTS - 2000



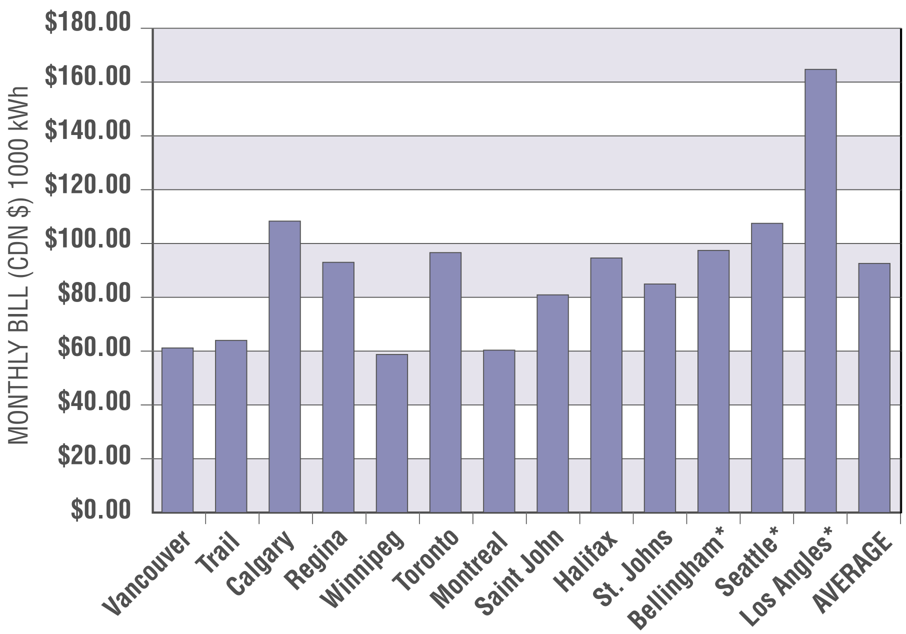
Low electricity rates and public ownership of BC Hydro

maintaining capacity and energy reserve margins (buffers of extra available generation and transmission), developing and applying short-term reliability standards, and participating in a western North American electricity reliability network.

Low electricity rates reflect major public investments in hydroelectric power made a generation ago.

Our electricity rates are among the lowest in North America. A previous generation's investment during the 1960s and 1970s has benefited all British Columbians over the past two decades. Today, hydroelectric facilities on the Peace and Columbia rivers account for approximately 75 percent of BC Hydro's generating capacity. Together with its coastal hydroelectric and thermal power plants, these heritage assets produce electricity at a much lower average cost than the cost of new generation or prices in neighbouring markets.

COMPARISON OF RESIDENTIAL ELECTRICITY RATES



B.C.'s low electricity rates are the direct legacy of abundant hydroelectric resources and a flexible power system that has enabled trade.

Some jusisdictions have a legacy of public investments in nuclear power, which has proven to be far less reliable as an energy source and far more costly than B.C.'s hydro-based system.

Our advantage in energy technologies offers domestic and export opportunities.

British Columbia profits from a growing alternative fuel industry, as well as expertise in hydroelectric power. The growth of firms such as Ballard Technologies (fuel cells) and Westport Innovations (natural gas vehicles) demonstrates our capacity for technology development. A recent survey of renewable energy strengths identified the Pacific Northwest as having the potential to become a world leader in solar photovoltaics and power transmission technologies.[6] This technological know-how can be used to develop new energy supplies within the province, and to generate additional revenues and jobs from trade.

CHANGING ENERGY MARKETS

Canadian natural gas markets have been deregulated since 1985.

In 1985, the federal government and western provinces agreed to deregulate natural gas to allow consumers to make their own purchase arrangements. Since then, high-volume industrial and commercial consumers have been able to purchase directly from natural gas producers as an alternative to the local distribution utility. All major pipelines provide open access, and an interconnected North American market now functions with little government intervention.

Other jurisdictions have reformed their electricity markets, with mixed success.

Electricity market reform has taken place in a number of other countries, including Great Britain, Norway, Australia, New Zealand, Argentina, Chile, and parts of the United States. In Canada, Alberta and Ontario have significantly restructured their electricity sectors. The rationale for change has generally been to support broader economic reforms (i.e., privatization), reduce electricity prices, and/or comply with access rules in interconnected markets. While there have been many successes in electricity reform, poor timing, inadequate planning, and a lack of regulatory foresight have led to difficulties in some jurisdictions.

The extent of market reform varies in other jurisdictions.

In general, reforms are intended to reduce costs by making electricity markets more competitive. Integrated utility monopolies are typically unbundled into separate generation, transmission and distribution entities. In some cases, generation and distribution are privatized and further divided into multiple companies to create competition. The transmission system is opened up, allowing private generators to sell to the distribution company (wholesale access/competition). A market is usually established to determine competitive pricing for this power. Private generators may also be allowed access to the distribution system, so that they can sell directly to electricity consumers (retail access/competition). Most jurisdictions undertaking such reforms have had power rates significantly higher than those in B.C.

B.C.'s electricity industry has undergone some changes over the past decade.

In the late 1980s, BC Hydro began requesting new generation projects from independent power producers (IPPs). Access to its transmission system, and to Aquila Networks Canada's system, was opened up in 1996. This allowed IPPs to use the transmission network to sell power into the export market, and BC Hydro's export subsidiary (Powerex) to trade directly in US wholesale markets. Starting in 1998, Aquila Networks Canada offered retail access to industrial customers. In June 2001, at the request of the BC Hothouse Growers' Association, the BC Utilities Commission granted approval to IPPs to access BC Hydro's distribution system. Most recently, BC Hydro has been reorganizing into functional business units for generation, transmission, and distribution, in order to make its operations more transparent and cost-effective.

Energy for Our Future: A Plan for BC provides a measured response to continue improving our power market.

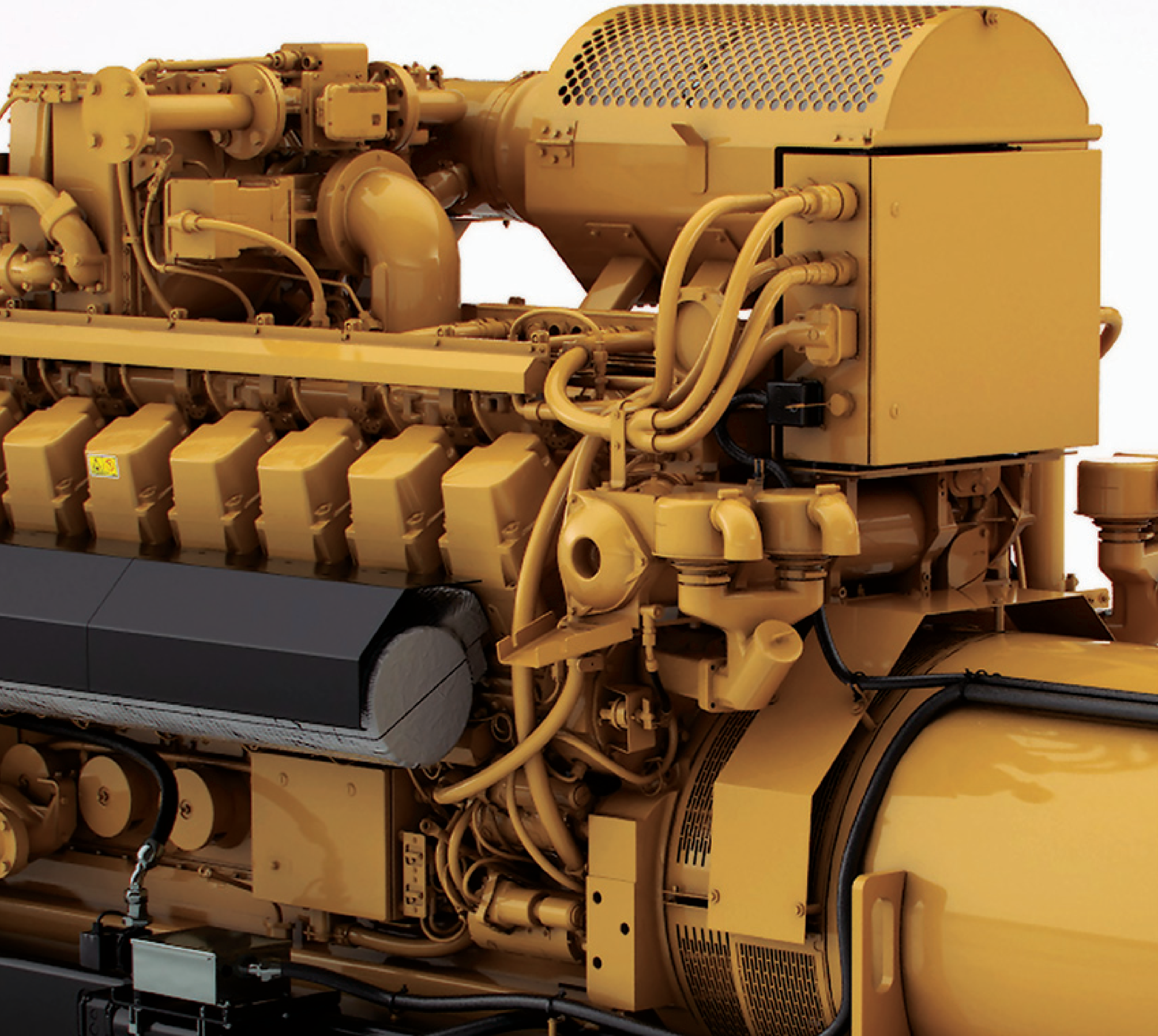
B.C. is not ready for, or in need of, large-scale electricity reform. To function properly, competitive markets require many buyers and sellers. Despite the recent growth in private power, the B.C. market is still dominated by a large Crown corporation with a concentration of low-cost generating assets. Moreover, our low power rates do not provide the same impetus for widespread reform as in higher-cost jurisdictions. At the same time, there are opportunities to introduce more competition in the development of new sources of electricity supply, while preserving the benefits of low-cost generation and trade revenues for provincial consumers. This plan includes actions to do just that.

5 United States, National Energy Policy, Report of the National Energy Policy Development Group, May 2001, p. 2-8.

6 Planit Management, Compass Resource Management, and Steeple-jack Consulting, Poised for Profit, Report Prepared for Climate Solutions, November 2001.

Energy for Our Future: A Plan for BC provides a measured response to continue improving our power market.

Attachment 15.12



CAT® G3500

Series Gas Generator Sets

CAT® G3500 SERIES
SMARTER ENERGY SOLUTIONS

COMMERCIAL AND INDUSTRIAL FACILITIES
Facilities such as manufacturing plants, resorts, shopping centers, office or residential buildings, universities, data centers and hospitals reduce operating costs and carbon footprint simultaneously.

ELECTRIC UTILITIES
Caterpillar has led innovation to deliver stationary and containerized gas power plants to electric utilities and district energy facilities around the world for both continuous grid support and peak electricity demand.

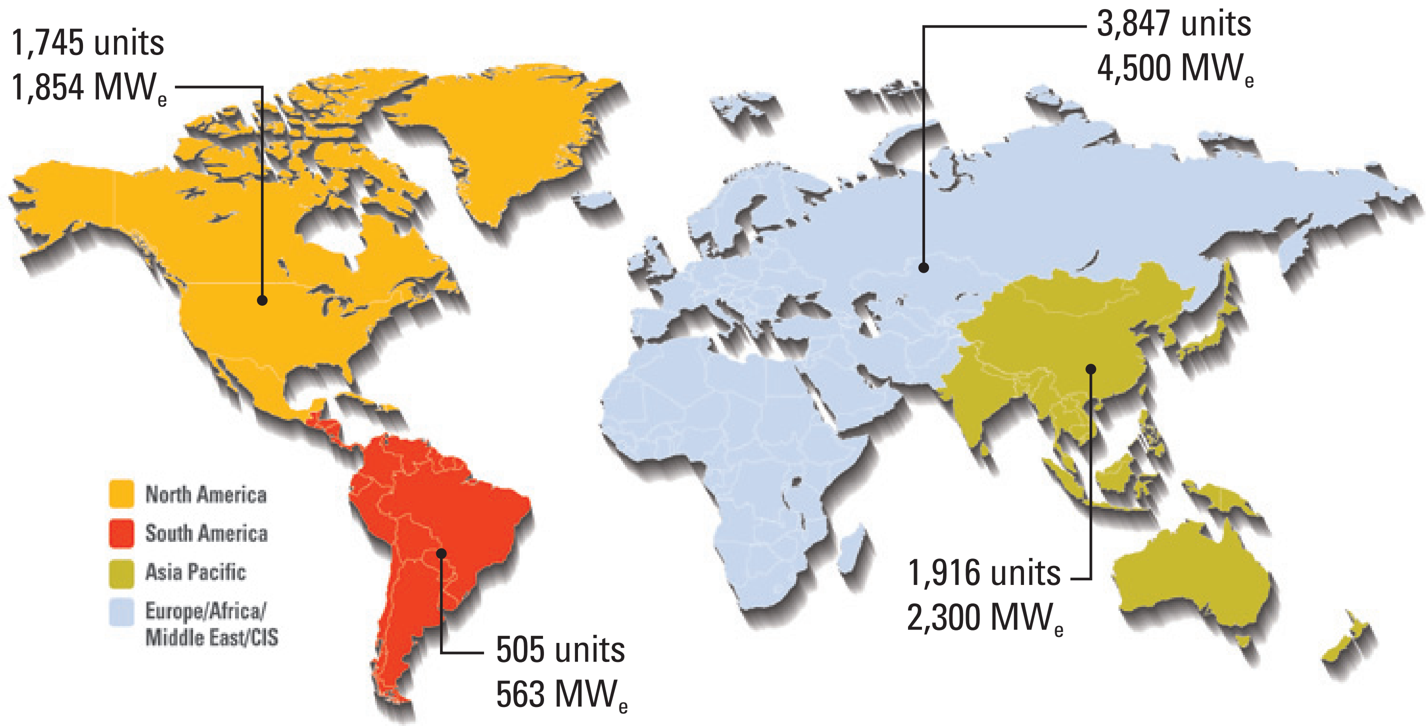
MINES
Mining operators increase mine safety and reduce carbon emissions with coal gas, while many other mining operations are realizing the benefits of onsite gas power generation to support greenfield site development.

AGRICULTURE AND FOOD / BEVERAGE PROCESSING
Biogas, a useful byproduct of the anaerobic digestion of organic waste, is created by food processors, ethanol and biodiesel manufacturers, and farms around the world as a renewable fuel resource for Cat® powered electricity generation.

LANDFILLS AND WASTEWATER TREATMENT PLANTS
Landfill and sewage gases are generated by communities around the world as part of sanitary process infrastructure. Instead of destroying or flaring the methane gas produced, communities make beneficial use of this fuel as part of a sustainable energy program.

GREENHOUSES
In greenhouses, Cat gas generator sets simultaneously deliver electricity for lighting or sale to the local grid, hot water for facility heating and carbon dioxide as an organic fertilizer for increased crop production.

Installed capacity of 9,217 MW_e with 8,013 generator sets worldwide



MEETING YOUR NEEDS HAS SHAPED OUR HISTORY

At Caterpillar, we understand what it takes to deliver a successful gas power generation system, and it starts with a core machine that is designed for efficiency and reliability. Since the 1920s, Caterpillar has been designing and building engines for power production. Although the technology has changed over the years, the philosophy hasn't: to deliver the most reliable power generation at the lowest possible cost of ownership and operation. Today, Caterpillar not only manufactures power generation equipment, but we also provide customized project financing via Cat Financial.

THE COMPLETE SOLUTION

Caterpillar is your complete gas solutions partner. From mechanical systems such as gas fuel train and heat recovery systems, to exhaust aftertreatment that complies with the world's most stringent emission requirements, Caterpillar Gas Solutions engineering works with your local Cat dealer to deliver a complete scope of supply. Caterpillar also provides electrical systems such as master controls and paralleling switchgear, electrical distribution switchgear and uninterruptible power supply (UPS) that can meet either UL or IEC requirements.

PRODUCT SUPPORT WORLDWIDE

Your gas power system is supported by our factory trained global network of Cat dealers. Therefore, you can rest assured that your equipment will be ordered, delivered, installed and commissioned in consultation with a local expert. You'll also have the confidence that Caterpillar will be there to keep you up and running. Cat dealers have over 1,600 dealer branch stores operating in 200 countries to provide the most extensive post-sales support including oil and fuel monitoring services, preventive maintenance and comprehensive Customer Support Agreements.

LOWER LIFE CYCLE COST

With longer maintenance intervals, higher fuel efficiency and competitive repair options, Caterpillar delivers the lowest total owning and operating costs. When you design your facility within Caterpillar's Application and Installation Guidelines, you can expect generator set availability up to 99 percent of planned operating hours annually. It all adds up to a strong return on your investment, year after year.

HIGHLY EFFICIENT PERFORMANCE

PRINCETON UNIVERSITY

PRINCETON, NEW JERSEY, USA

In 2011, Caterpillar delivered a G3520E 60 Hz gas generator set rated for 2,000 kW_e designed for waste heat recovery for the University's new High-Performance Computing Resource Center. The project helps support campus-wide energy efficiency goals.

BINATOM ELECTRIC PRODUCTION

KUTHAYA REGION, TURKEY

This independent power producer in northern Turkey demonstrated the plug-and-play design of Caterpillar's latest G3516H gas generator set. With the local Cat dealer also supplying the CHP system and fuel train, complete installation and commissioning was completed in just seven days.

HBG–HEIZWERKBETRIEBSGESELLSCHAFT

REUTLINGEN, GERMANY

This district power and heating plant had been operating Cat G3520C generator sets at total system efficiency near 100 percent based on condensing heat exchangers and industrial heat pumps. When a new plant was commissioned in 2012 with a next generation G3516H, the plant manager declared it "the easiest genset startup we've seen."

RIES

HIGHLY EFFICIENT

The E & H Series takes electrical efficiency to the next level, up to 44.7 percent (1.0PF, ISO). Improved performance is delivered via a combination of new piston ring liner packs, optimized turbochargers, updated controls, crankcase recirculation system and low-loss steel generator construction.

CUSTOM ENGINEERED TO CUSTOMER SPECS

Whether your goals are achieving the lowest fuel consumption, lowest emissions, high load response, or just surviving challenging high ambient conditions, the E & H Series offers tailored turbochargers, air systems and controls that are matched to your performance requirements.

LOWEST MAINTENANCE COSTS

The E & H Series consumes U.S. $14,000 less oil per year than competitive engines, achieving a mid-life oil consumption below 182 mg/kW_m-h (0.0003 lb/bhp-h). Major planned overhauls up to 80,000 hours ensure the lowest possible long-term owning and operating costs.

C SERI

RESPONSIVE AND DURABLE

JINCHENG COAL MINING GROUP LTD.

JINCHENG, SHANXI, CHINA

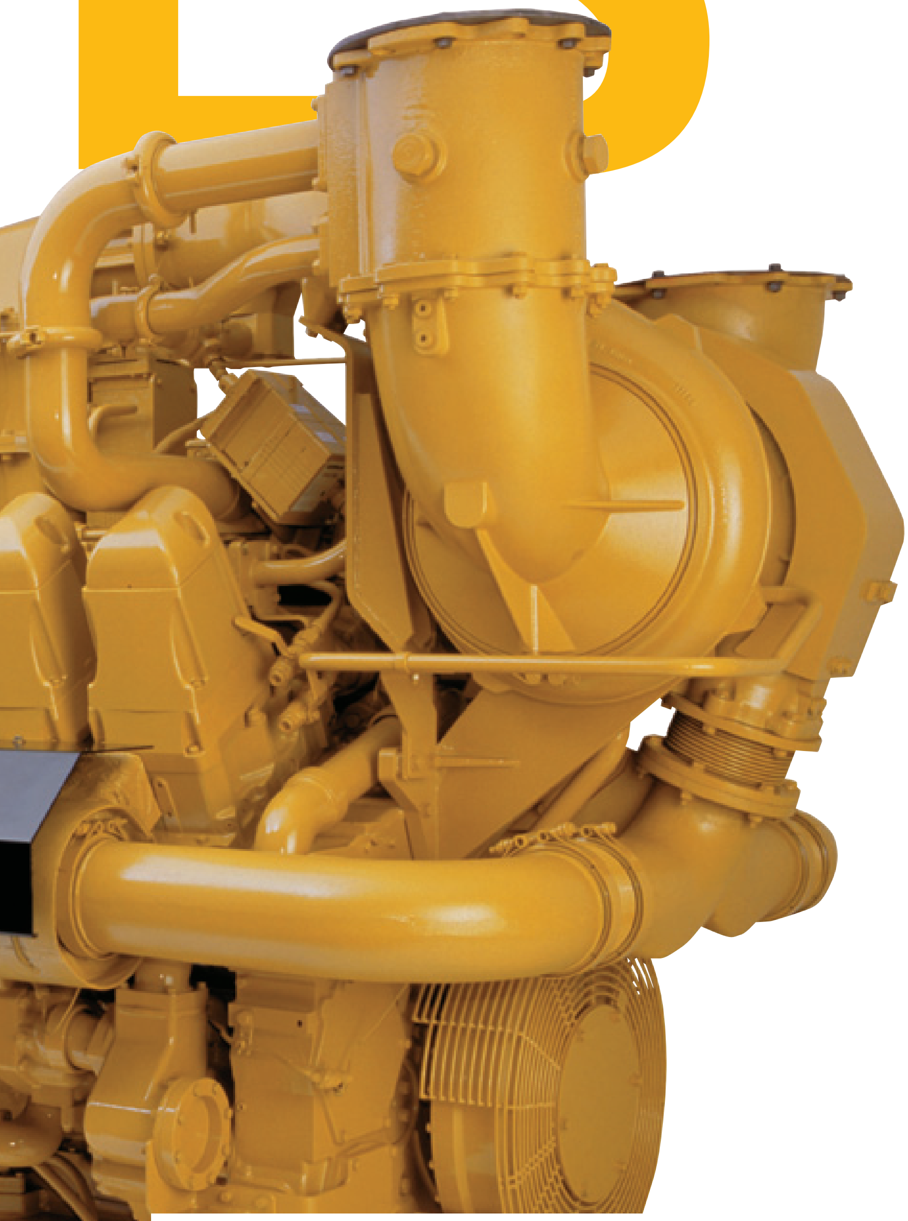
The largest coal-mine-methane fueled power plant in the world employs 60 Cat G3520C generator sets to divert harmful coal gas from entering the atmosphere while generating cost-effective electricity for over a half million Chinese homes.

BIFFA POPLARS LANDFILL

CANNOCK, UNITED KINGDOM

A power expansion of 4 MW was made possible with two landfill powered G3520C generators sets in custom outdoor enclosures. Engine heat is recovered for leachate treatment and the entire system can be operated remotely.

ES



WENTWORTH RESOURCES

MNAZI BAY & MTWARA, TANZANIA

Local natural gas resources fuel nine G3520C generator sets to provide the area's first reliable utility power source, resulting in economic prosperity never before experienced by the local community.

HARDENED AGAINST CONTAMINANTS

Since 2005, the C Series has become the industry leader for operation on landfill gas, agricultural biogas and sewage gas fuels. Specially treated aftercooler cores, cylinder heads and rear gear train bearings are hardened against corrosive biogas elements. Elevated jacket water temperatures and crankcase ventilation discourage harmful acidic condensation.

BEST-IN-CLASS LOAD RESPONSE

The island mode version of the C Series generator sets provide the best option in the industry for efficient operation disconnected from the utility grid thanks to a specialized controls architecture. When block loads are applied up to 25 percent of nameplate rating, the generator set recovers to nominal frequency and voltage within 10 seconds (ISO8528-5 Class G1).

SPECIAL PROJECT CAPABILITY

Caterpillar is investing in research and development programs on the C Series platform that allow for operation on specialty fuels such as syngas, blast furnace gas, coke oven gas and ultra-low methane coal gas.

B SERI

BALANCED AND ADAPTABLE

BOGORODSKOE INDUSTRIES LLC
BOGORODSKOE, RUSSIA

With only four months to transport and construct a complete heat and power facility to support the city of Bogorodskoe, Caterpillar and local dealer Amur Machinery commissioned three G3516B generator sets in arctic grade enclosures with a heat recovery system that delivers 90 percent system efficiency.

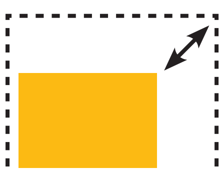
SIEMENS BUILDING TECHNOLOGIES
MILFORD, MASSACHUSETTS, USA

Monroe County saves $1 million per year in energy costs by implementing four Cat G3516B in a trigeneration scheme that produces 5.4 MW of electricity along with hot water and summer cooling for the Monroe County Community College.

FINNING RENTAL POWER
EDMONTON, ALBERTA, CANADA

Finning Rental Power is the largest provider of Cat gas rental power services in North America. Their fleet includes over 20 Cat XQ1250G power modules using G3516B generator sets that deliver temporary power to industrial, commercial and petroleum projects across Western Canada.

A TECHNOLOGY FIRST
The G3500B Series was the first Cat gas generator set to introduce several technologies: fully electronic control, automated air fuel ratio adjustment, pre-chamber spark plugs, transient richening with turbo bypass and individual cylinder detonation control.



ADAPTABLE
With standard natural gas configurations designed to handle Cat methane numbers down to 60 MN, the B Series is particularly adept at handling pipeline fuels that experience seasonal variability. Recent updates allow for high efficiency operation on lower MN fuels such as propane.

A FIRST IN MOBILITY
The G3516B generator set was the first lean burn gas generator set in the world to be offered as a fully mobile, containerized power plant. The XQ1250G rental module was introduced in 2004, and updated in 2010 to include updated generator set and utility paralleling controls, improved fuel train and lower exhaust emissions.

A SERI

HANGZHOU MUNICIPAL SOLID WASTE TREATMENT COMPANY LTD.
HANGZHOU, ZHEJIANG, CHINA

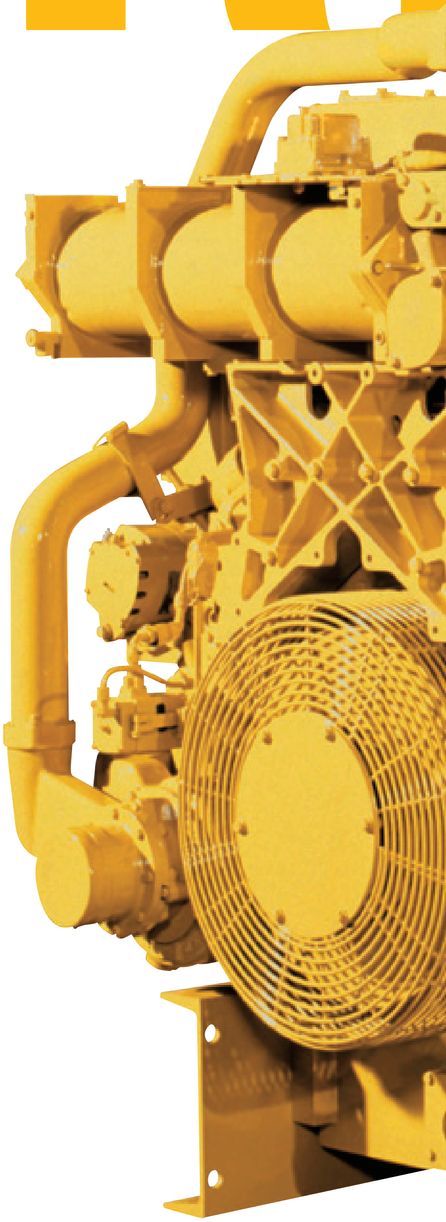
To power the first major landfill-gas-to-energy project in China, the local authorities selected two G3516A landfill gas generator sets. After 10 years and 80,000 hours of successful operation without a major overhaul, in 2011 Caterpillar was again selected to provide two more G3516A generator sets for an expansion site.

ENERDYNE POWER SYSTEMS
ALCOA, TENNESSEE, USA

To maximize the 1 MW of renewable energy allowed for export to the local grid, in 2011 Caterpillar delivered a unique G3516A gas generator set in a custom outdoor enclosure, with a custom gear train, and low NO_x setting that allowed the customer to operate at maximum power for maximum profit.

ENGINE DEVELOPMENTS LTD., APPIN COAL MINE
NEW SOUTH WALES, AUSTRALIA

In 1995, 94 G3516A coal gas generator sets were commissioned to provide a first-of-a-kind in sustainable energy: electricity from underground coal gas. In 2012, after many engines reached 100,000 operating hours without a major overhaul, power plant owner-operator EDL extended their power contract for four more years.

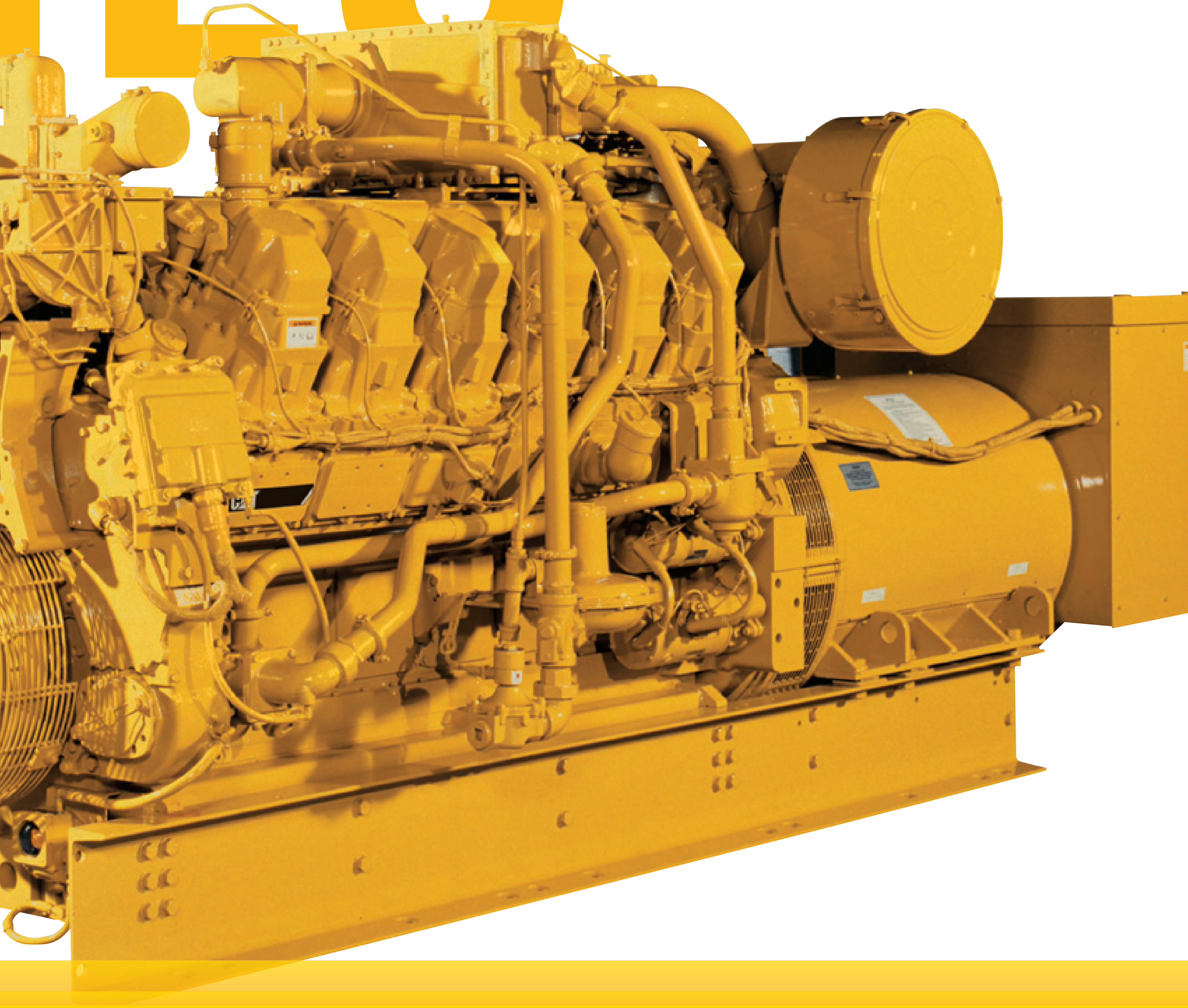


AN INDUSTRY WORKHORSE FOR 25 YEARS

ULTIMATE RELIABILITY

With over 10,000 gas engine generators sold over the past 25 years, the G3500A Series is a proven performer in hundreds of different applications. With unparalleled uptime and ease of maintenance, consultants around the world continue to specify the A Series for its reliability.

IES



THERMAL EFFICIENCY

No other gas generator set on the market can deliver the same diversity of heat for combined heat and power applications. The A Series can utilize up to a 127°C (260°F) jacket water circuit to deliver 15 psi (1 bar) steam while also providing 145 psi (10 bar) steam via exhaust heat recovery.

FUEL FLEXIBILITY

Whether your fuel is coal gas, landfill gas, propane, LNG, agricultural biogas, or associated gas, the A Series has a configuration specifically designed to handle a variety of fuels and applications. This flexibility also extends to extreme ambient conditions and altitudes without derate or risk of detonation.

50HZ PRODUCT PERFORMANCE: BIOGAS

PHYSICAL DATA	UNITS		G3508A		G3512A	
Bore / Stroke	mm	in	170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5
Displacement	l	in^3	35.0	2105	52.0	3158
Engine Speed	rpm		1500		1500	
Length 1)	mm	in	3674	145	4333	171
Width 1)	mm	in	2156	85	2160	85
Height 1)	mm	in	2126	84	2063	81
Dry weight genset	kg	lb	7,642	16,850	9,161	20,201

PERFORMANCE	UNITS		G3508A		G3512A	
Emission setting (NO_x)*	mg/m_n^3	g/bhp-h	500	1	500	1
Electrical power 2)	kW_e		457		777	
Mean effective pressure	bar	psi	12.4	180	12.4	180
Thermal output 3)	kW_{th}	Btu/m	716	40,726	1,310	74,480
Electrical efficiency 2)	%		30.1		30.8	
Thermal efficiency 3)	%		49.3		52.7	
Total efficiency	%		79.4		83.5	
Cat Ref. #			DTO / DM3166		DTO / DM0762	

60HZ PRODUCT PERFORMANCE: BIOGAS

PHYSICAL DATA	UNITS		G3508A		G3512A	
Bore / Stroke	mm	in	170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5
Displacement	l	in^3	35.0	2105	52.0	3158
Engine Speed	rpm		1200		1200	
Length 1)	mm	in	3944	155	3944	155
Width 1)	mm	in	1736	68	1736	68
Height 1)	mm	in	2007	79	2126	84
Dry weight genset	kg	lb	7,619	16,800	9,161	20,201

PERFORMANCE	UNITS		G3508A		G3512A	
Emission setting (NO_x)*	mg/m_n^3	g/bhp-h	859	2	759	2
Electrical power 2)	kW_e		408		615	
Mean effective pressure	bar	psi	12.4	180	12.4	180
Thermal output 3)	kW_{th}	Btu/m	592	33,640	1,018	57,920
Electrical efficiency 2)	%		32.2		29.6	
Thermal efficiency 3)	%		45.8		48.1	
Total efficiency	%		78.0		77.7	
Cat Ref. #			DTO / DM8672		DTO / DM8651-00	

Notes
1) Transport dimensions of genset only. Accessory components must be taken into account separately.
2) Series (A, B, C-60Hz, C-50Hz-Biogas) include losses for engine-mounted JW & AC mechanical coolant pumps. Series (C-50Hz-Natural Gas, E, & H) exlcude engine-mounted JW & AC pumps. In accordance with ISO 3046/1 using standard low voltage (medium voltage for > 2000kW) generator at PF=1.0. Assumes methane number of MN80 for natural gas, MN 130 for biogas.
3) In accordance with nominal tolerances. Calculated as exhaust gas heat cooled (to 120°C) plus engine jacket water circuit heat.
* NO_x emissions as NO_2 dry exhaust gas @ 5% O_2 with 54°C (130°F) SCAC inlet temperature [48°C (118°F) for H Series]. <500 mg/m_n^3 (1.0g/bhp-h) NO_x performance available via engine setting for lean burn engines or via 3-way catalyst for rich burn engines. Ultra-low NO_x options available via SCR catalyst.

Biogas fuels (landfill gas, sewage gas, digester gas) assumed to meet published engine-in contaminant limits with minimum heating value (LHV) = 18.0 MJ/m_n^3 (457 Btu/scf).
Natual gas fuels assumed to be mostly methane with a lower heating value (LHV) = 35.6 MJ/m_n^3 (905 Btu/scf).
Specifications for special gases are available.
Data is representative and non-binding. Contact your Cat dealer for generator set, site and fuel-specific performance.

G3516A		G3516A+		G3520C	
170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5
69.0	4210	69.0	4210	86.0	5266
1500		1500		1500	
4906	193	4906	193	6316	249
2155	85	2155	85	1828	72
2051	81	2072	82	2254	89
17,824	39,303	17,778	39,200	17,826	39,306

G3516A		G3516A+		G3520C	
500	1	500	1	500	1
1041		1105		1991	
12.4	180	13.2	191	18.9	274
1,556	88,475	1,245	70,803	2,323	132,098
32.1		36.8		39.3	
47.0		41.5		44.7	
79.1		78.3		84.0	
516GE87 / DM0761-03		DTO / S02-35-03		520GE37 / DM8647-03	

G3516A		G3516A+		G3520C		G3520C	
170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5
69.0	4210	69.0	4210	86.0	5266	86.0	5266
1200		1200		1200		1500	
4320	170	4913	193	6322	249	7557	298
2284	90	1736	68	1803	71	2170	85
1940	76	1940	76	2465	97	3212	126
12,549	27,670	12,549	27,670	17,339	38,232	22,425	49,447

G3516A		G3516A+		G3520C		G3520C	
787	2	500	1	439	1	500	1
824		1015		1622		1936	
12.4	180	15.2	221	19.4	281	18.9	274
1,266	71,985	1,145	65,125	1,665	94,704	2,322	132,049
31.0		36.1		39.8		38.7	
47.6		39.9		39.9		44.7	
78.6		76.0		79.7		83.4	
516GE71 / DM5480-00		DTO / WG12-3500-9(02)		520GE38 / DM5859-05		520GE38 / DM8647-03	

50HZ PRODUCT PERFORMANCE: NATURAL GAS

PHYSICAL DATA	UNITS		G3508A		G3512A		G3516A		G3512E		G3516B	
Bore / Stroke	mm	in	170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5
Displacement	l	in^3	33.0	2015	52.0	3158	69.0	4210	52.0	3158	69.0	4210
Engine Speed	rpm		1500		1500		1500		1500		1500	
Length [1)]	mm	in	3581	141	4332	171	4909	193	4625	182	4848	191
Width [1)]	mm	in	1570	62	2160	85	2197	86	1828	72	2091	82
Height [1)]	mm	in	2012	79	2063	81	2015	79	2255	89	2350	93
Dry weight genset	kg	lb	9,229	20,351	10,807	23,830	12,384	27,306	11,347	25,021	13,370	29,480

PERFORMANCE	UNITS		G3508A		G3512A		G3516A		G3512E		G3516B	
Emission setting (NO_x)*	mg/m_n^3	g/bhp-h	500	1	500	1	834	2	500	1	500	1
Electrical power [2)]	kW_e		485		777		983		1017		1088	
Mean effective pressure	bar	psi	11.7	170	12.4	180	11.7	170	16.2	235	13.1	190
Thermal output [3)]	kW_{th}	Btu/m	632	35,914	1,213	68,964	1,392	79,169	1,100	62,534	1,492	84,826
Electrical efficiency [2)]	%		37.2		31.9		34.8		41.5		37.1	
Thermal efficiency [3)]	%		48.5		48.8		48.3		43.7		49.9	
Total efficiency	%		85.7		80.7		83.1		85.2		87.0	
Cat Ref. #			508GEX3 / DM5232-03		512GE04 / DM0762-03		516GE88 / DM5158-02		512GE17 / DM8801-04		516GE83 / DM5641-01	

60HZ PRODUCT PERFORMANCE: NATURAL GAS

PHYSICAL DATA	UNITS		G3508A		G3508A		G3512A		G3512A		G3516A	
Bore / Stroke	mm	in	170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5
Displacement	l	in^3	33.0	2015	33.0	2015	52.0	3158	52.0	3158	78.0	4210
Engine Speed	rpm		1200		1200		1200		1200		1200	
Length [1)]	mm	in	3821	150	3821	150	4281	169	4281	169	3280	129
Width [1)]	mm	in	1570	62	1570	62	1736	68	1736	68	1712	67
Height [1)]	mm	in	2012	79	2012	79	1940	76	1940	76	1860	73
Dry weight genset	kg	lb	7,393	16,301	7,393	16,301	10,807	23,830	10,807	23,830	12,549	27,670

PERFORMANCE	UNITS		G3508A		G3508A		G3512A		G3512A		G3516A	
Emission setting (NO_x)*	mg/m_n^3	g/bhp-h	9498	26	857	2	8399	21	844	2	9791	24
Electrical power [2)]	kW_e		373		380		564		583		755	
Mean effective pressure	bar	psi	11.4	165	11.7	170	11.4	165	11.7	170	11.7	170.0
Thermal output [3)]	kW_{th}	Btu/m	591	33,616	441	25,097	961	54,629	779	44,293	1,146	65,178
Electrical efficiency [2)]	%		32.7		34.4		32.5		34.5		33.0	
Thermal efficiency [3)]	%		51.8		39.2		55.2		45.2		49.1	
Total efficiency	%		84.5		73.6		87.7		79.7		82.1	
Cat Ref. #			508GE08 / DM5205-03		508GE09 / TM9729-04		512GE12 / DM5207-03		512GE13 / DM0745-05		516GE67 / DM5663	

Notes
1) Transport dimensions of genset only. Accessory components must be taken into account separately.
2) Series (A, B, C-60Hz, C-50Hz-Biogas) include losses for engine-mounted JW & AC mechanical coolant pumps. Series (C-50Hz-Natural Gas, E, & H) exlcude engine-mounted JW & AC pumps. In accordance with ISO 3046/1 using standard low voltage (medium voltage for > 2000kW) generator at PF=1.0. Assumes methane number of MN80 for natural gas, MN 130 for biogas.
3) In accordance with nominal tolerances. Calculated as exhaust gas heat cooled (to 120°C) plus engine jacket water circuit heat.
* NO_x emissions as NO_2 dry exhaust gas @ 5% O_2 with 54°C (130°F) SCAC inlet temperature [48°C (118°F) for H Series]. <500 mg/m_n^3 (1.0g/bhp-h) NO_x performance available via engine setting for lean burn engines or via 3-way catalyst for rich burn engines. Ultra-low NO_x options available via SCR catalyst.
** Orders available beginning Dec. 2013

Biogas fuels (landfill gas, sewage gas, digester gas) assumed to meet published engine-in contaminant limits with minimum heating value (LHV) = 18.0 MJ/m_n^3 (457 Btu/scf).
Natual gas fuels assumed to be mostly methane with a lower heating value (LHV) = 35.6 MJ/m_n^3 (905 Btu/scf).
Specifications for special gases are available.
Data is representative and non-binding. Contact your Cat dealer for generator set, site and fuel-specific performance.

G3512E		G3516E		G3516C		G3520C		G3516H		G3520E	
170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5	170 / 215	6.7 / 8.5	170 / 190	6.7 / 7.5
52.0	3158	69.0	4210	69.0	4210	86.0	5266	78.0	4765	86.0	5248
1500		1500		1500		1500		1500		1500	
4594	181	5523	217	5553	219	6259	246	5979	235	6893	271
1647	65	1828	72	1828	72	1828	72	1921	76	2001	79
2255	89	2340	92	2340	92	2254	89	2307	91	2727	107
12,460	27,475	13,366	29,472	14,161	31,226	17,826	39,306	16,397	36,156	17,826	39,306

G3512E		G3516E		G3516C		G3520C		G3516H		G3520E	
500	1	500	1	500	1	500	1	500	1	500	1
1211		1603		1605		2019		2027		2039	
19.2	279	19.2	278	19.2	279	19.2	278	21.3	309	19.5	283
1,226	69,727	1,634	92,897	1,830	104,096	2,282	129,786	1,937	110,155	2,164	123,056
42.2		41.6		40.1		40.3		44.7		42.4	
41.8		41.4		44.6		44.5		41.3		44.0	
84.0		83.0		84.7		84.8		86.0		86.4	
512GE18 / DM8811-04		516GE48 / DM5790-02		516GE24 / DM8678-04		520GE87/88 / EM0301-01		DTO / EM0500-00		520GE62 / DM8916-00	

G3516A		G3516B		G3520C		G3516C		G3516H**		G3520E		G3520C	
170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5	170 / 215	6.7 / 8.5	170 / 190	6.7 / 7.5	170 / 190	6.7 / 7.5
69.0	4210	69.0	4210	86.0	5266	69.0	4210	78.0	4765	86.0	5248	86.0	5270
1200		1800		1200		1800		1500		1500		1800	
4913	193	4203	165	6312	249	5518	217	7395	291	7013	276	6367	251
1736	68	2155	85	1830	72	1830	72	2139	84	2032	80	1997	79
1940	76	2419	95	2340	92	2340	92	2402	95	2730	107	2340	92
12,549	27,670	12,618	27,823	17,339	38,232	13,748	30,315	18,315	40,384	21,454	47,306	17,215	37,959

G3516A		G3516B		G3520C		G3516C		G3516H**		G3520E		G3520C	
844	2	407	1	500	1	443	1	500	1	500	1	446	1
779		1312		1626		1663		2008		2026		2077	
11.7	170	13.0	189	19.4	282	16.6	241	21.3	309	19.3	280	16.6	241
1,087	61,819	1,817	103,314	1,749	99,449	2,100	119,412	1,937	110,155	2,164	123,056	2,627	149,402
35.0		35.5		40.8		37.6		44.3		42.2		38.0	
48.8		48.3		42.8		46.4		41.3		44.0		46.9	
83.8		83.8		83.6		84.0		85.6		86.2		84.9	
516GE68 / DM0739-00		516GE86 / DM5495-04		520GE34 / DM0881-00		516GE75 / DM5784-01		DTO / EM0500-00		520GE62 / DM8916-00		520GE10 / DM3194-02	

For more information and to contact your local Cat dealer,
visit www.catgaspower.com

LEBE0023-02 April 2013

Attachment 18.1

Biomethane Greenhouse Gas Emissions Review

FortisBC

May 30th, 2011

OFFSETTERS

Executive Summary

Based on a review of BC Government Policy and the expected lifecycle emissions for biomethane produced from landfill gas and anaerobic digesters, Offsetters considers FortisBC's renewable natural gas to be a carbon neutral fuel. As such, participants that sign up for renewable natural gas will see a reduction in their carbon footprint by 5.03 kgCO_2e per gigajoule, based a fuel mix of 10% biomethane. One gigajoule of 100% biomethane will provide a savings of 50.3 kgCO_2e when replacing conventional natural gas in BC.

Existing policy related to biomethane shows that the Government of British Columbia considers biomethane from organic waste (including agriculture, landfill or wastewater sources) to be a carbon neutral fuel source. The following are organizations and documents that refer to the carbon neutrality of biomethane:

i. Provincial Government of British Columbia in the "Budget and Fiscal Plan 2011/12- 2013/14" (February 15th, 2011)
ii. Provincial Government of British Columbia, Ministry of Energy, Mines and Petroleum Resources in the BC Bioenergy Strategy
iii. Report by Biocap for the BC Ministry of Energy, Mines and Petroleum Resources and the BC Ministry of Forests and Range. Document titled, "An Information Guide on Pursuing Biomass Opportunities and Technologies in British Columbia"

In the case of renewable natural gas, Carbon Neutral status means that both combustion and lifecycle emissions do not contribute any net greenhouse gases into the atmosphere. The combustion of biomethane releases biogenic carbon dioxide, which is not additional to the natural carbon cycle. From a lifecycle perspective, the emissions savings from displacing conventional natural gas production far outweigh biomethane's production emissions.

Throughout the life cycle of biomethane, expected sources of greenhouse gas (GHG) emissions include:

a. Energy required for processing biomethane including the electricity and fuel consumed by facilities, equipment and support vehicles;

b. Methane slip that may occur during processing, transport and distribution;

c. Energy required for transport and distribution, such as the electricity consumed in distribution facilities and pipeline operations;

d. Methane and nitrous oxide emissions resulting from biomethane combustion at the point of consumer use; and,

e. By- product waste created throughout all life cycle stages such as wastewater and solid deposits.

Expected GHG sinks in the biomethane life cycle that reduce greenhouse gas emissions include:

a. Methane capture and destruction from landfill gas, manure management and wastewater treatment. Under baseline conditions, organic material would typically decompose and release methane directly into the atmosphere;

b. Avoided emissions from the combustion of natural gas, a fossil fuel that emits 50.3014 $kgCO_2e/GJ$ in BC. Biomethane emits only 0.3034 $kgCO_2e/GJ$;

c. Avoided life cycle emissions from extracting and processing natural gas; and,

d. Avoided emissions from nitrous oxide released from untreated biomass.

It is important to consider renewable natural gas' additional benefit of converting naturally occurring biomethane into carbon dioxide as mentioned above. The process of biomethane "capture and destruction" reduces global warming impacts considerably. Methane has a global warming potential (GWP) of 21 while carbon dioxide's GWP is 1, which means that each molecule of methane has 21 times the impact on climate change as one molecule of carbon dioxide. Utilizing biomethane for heating and other purposes creates carbon dioxide and prevents biomethane from directly entering the atmosphere, which reduces overall greenhouse gas emissions.

Contents

Figures

Tables

1 Introduction

1.1 Purpose

This report has been conducted by Offsetters on behalf of FortisBC. The purpose of this report is to:

1. Summarize existing policies in British Columbia that define biomethane as a 'carbon neutral' fuel source.

2. Identify emissions sources and overall net emissions associated with the life cycle of biomethane produced from landfills and anaerobic digesters.

1.2 Disclaimer

All greenhouse gas emissions quantified in this report are estimations based on existing data from previous studies conducted and therefore Offsetters is not responsible for inaccuracies of 3rd party information.

1.3 Life cycle Assessment (LCA) Background

Drawing from the World Resources Institute's Life Cycle Standard, there are two LCA boundaries that we recognize in the preparation of this study:

1) Cradle-to-Grave:

A cradle-to-grave life cycle assessment includes all GHG emissions in the complete life cycle of a product from the beginning of acquiring raw materials through final disposal or post-consumer end-of-life.

In the case of a fuel cycle, the cradle-to-grave emissions are also referred to as well-to-wheels (WTW). The WTW life cycle includes resource extraction, feedstock production, fuel production, refining, blending, transportation and distribution, consumption and evaporation.

Figure 1 below illustrates the five life cycle stages of a product.

Figure 1: Cradle-to-Grave Emission Stages

2) Cradle to Gate:

A cradle to gate inventory does not include the use or end-of-life stages. For fuel, the cradle to gate emissions are also referred to as well- to- tank (WTT). The WTT life cycle therefore includes resource extraction, feedstock production, fuel production, refining, blending, transportation and distribution.

Figure 2: Cradle- to- Gate Inventory

This report examines emissions information up to the biomethane producer's gate, where the biomethane is transferred into FortisBC's pipeline distribution network.

2 Review of BC's Biomethane Policies

Offsetters has conducted a review of existing government policy related to biomethane and carbon neutrality in British Columbia on behalf of FortisBC. Tables 1-3 below provide excerpts from these documents. They are either Provincial Government documents or are written by third parties on behalf of the Government.

The consensus from these documents is that the Government of British Columbia considers biomethane sourced from organic waste (including agricultural, landfill or wastewater sources) to be a carbon neutral fuel source. The Government's position states biomethane releases no more carbon into the atmosphere than it absorbs in its lifetime.

2.1 British Columbia Budget

In BC's latest Budget and Fiscal Plan, published on February 15th, 2011, biomethane produced from agricultural and other organic waste is referenced as a carbon neutral renewable fuel. According to the Carbon Tax Act, the biomethane portion of a fuel blend is to be exempt from the carbon tax as a result of its carbon neutrality. Table 1 below provides a summary of this section of the Budget and Fiscal Plan, with a quote directly from page 42 of the document.

Table 1: Provincial Government: Budget and Fiscal Plan 2011/2012 (Excerpt)

Organization
Provincial Government of British Columbia
Document
Budget and Fiscal Plan 2011/12- 2013/14 (February 15th, 2011)
Quote Page 42:
"Biomethane is a carbon neutral fuel produced from biomass (eg. Agricultural and other organic wastes). Purchases of 100% biomethane are exempt from carbon tax. The biomethane portion of a blend is exempt from the carbon tax where the actual amount of biomethane in the blend is known. Effective February 16, 2011, a credit is provided for blends of biomethane and natural gas sold under qualifying contracts by registered retail dealers of natural gas who inject biomethane into the system. Qualifying contracts must clearly stipulate the amount that purchasers are paying for a specified volume or percentage of biomethane. The credit is equal to the carbon tax payable on the specified volume or percentage of biomethane. Similar to the Residential Energy Credit, eligible purchasers will receive the biomethane credit on their natural gas bills."

2.2 BC Ministry of Energy, Mines and Petroleum Resources

The BC Provincial Ministry of Energy, Mines and Petroleum Resources published a report titled, *BC Bioenergy Strategy: Growing Our Natural Energy Advantage*. In this report, biomass refers to organic sources including agricultural waste and manure. The report also states that when used for energy, biomass including organic waste is carbon neutral. Table 2 below provides a direct quote from page 4 of this report, which relates to biomass and carbon neutrality.

Table 2: BC Bioenergy Strategy

Organization
Provincial Government of British Columbia, Ministry of Energy, Mines and Petroleum Resources
Document
BC Bioenergy Strategy
Quote Page 4:
"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."

2.3 BC Ministry of Energy, Mines and Petroleum Resources and the BC Ministry of Forests and Range

In 2008 the BC Ministry of Energy, Mines and Petroleum Resources and the BC Ministry of Forests and Range published an information guide on biomass energy opportunities in British Columbia. This report was prepared by Biocap Canada on behalf of the two Ministries. In this report, biomass refers to municipal solid waste, agricultural waste including livestock manure and forestry waste. This report states that biomass as a carbon neutral energy source can play an important role in helping BC achieve its GHG targets. Table 3 below provides a summary of the explanations provided in this report related to biomass and carbon neutrality. Of note, page 20 of this report recognizes the potential of methane emissions from biomass contributing to GHGs and how this should be avoided through a biofilter.

Table 3: Information Guide to Biomass in BC

Organization
Report by Biocap for BC Ministry of Energy, Mines and Petroleum Resources and the BC Ministry of Forests and Range
Document
An Information Guide on Pursuing Biomass Energy Opportunities and Technologies in British Columbia (February 7^{th}, 2008)
Quote Page 4:
"The Province of British Columbia has committed itself to maintain a share of at least 90% of its electricity generation from clean and renewable energy sources, and to mandate that all new facilities will have net zero greenhouse gas emissions. Biomass, as a "carbon neutral" renewable resource, can make a major contribution towards this goal. In addition, biomass can also support energy and greenhouse gas emission reduction goals in the fields of heat and transportation fuels. One tonne of dry biomass (bdt) can displace between 1.5 and 3 barrels of oil, depending on the application, technology and process efficiency applied."
Quote from Page 20:
"Note that carbon contained in biomass is usually considered part of a regeneration cycle and processes using biomass can therefore be considered carbon neutral. However, any methane emissions should be avoided as they would otherwise constitute GHG emissions. Methane emissions can occur during curing of the material, but can be partly eliminated by the biofilter. The anaerobic digestion process will generate GHG credits through avoided emissions in the field or from open lagoons, as well the from the electricity or natural gas displaced when using the digester gas for energy purposes."

2.4 Considerations

1. Non-Biogenic Emissions

Notwithstanding the BC Government's position on biomethane, it should be noted that biogenic emissions from biomethane combustion refer to carbon dioxide (CO_2) emissions only. The use of biomethane also results in greenhouse gas emissions of uncombusted methane (CH_4) and nitrous oxide (N_2O), which total 0.3034 kgCO_2e/GJ. However, the BC Government considers these non-biogenic emissions to be immaterial and negligible as they represent only 0.6% of the total emissions from conventional natural gas that has an emissions factor of 50.3 kgCO_2e/GJ in BC as reported by Environment Canada[1] and the BC Ministry of Environment[2].

2. Biomass vs. Woody Biomass

The use of the term "biomass" can sometimes refer to all types of biomass (including biomethane) or it can refer to the subset of woody biomass only. This distinction is important because the BC Reporting Regulation for the Greenhouse Gas Reductions (Cap and Trade) Act[3], exempts woody biomass from a reporting facility's emissions total. However, facilities are required to report emissions from biomass sources other than those listed in Schedule C, including biomethane emissions. It is unclear why biomethane emissions are not exempt.

"Biomass" is defined as:

> "(a) non-fossilized plants or parts of plants, animal waste or any product made of either of these and includes, without limitation, biomass derived fuels, wood and wood products, agricultural residues and wastes, biologically derived organic matter found in municipal and industrial wastes, landfill gas, black liquor, kraft pulp fibres and sludge gas, and
> (b) any fuels in respect of which the entire heat generation capacity is derived entirely from biomass described in paragraph (a);"

"Woody Biomass" is defined as "Type 1 biomass" in Schedule C as follows:

> Wood biomass, or the wood biomass component of mixed fuels, including
> (a) wood residue within the meaning of the Forest Act,
> (b) wood-derived fuel, red liquor and black liquor from pulp and paper production processes, and
> (c) woody matter from agricultural trimmings, tree thinning and orchard removals,
> but not including wood biomass that fails to meet the criteria for carbon neutrality established by the jurisdiction in which it was produced, if any.

---

[1] 1990-2008 National Inventory Report (April 2009), Greenhouse Gases and Sinks in Canada http://www.ec.gc.ca/Publications/default.asp?lang=En&xml=492D914C-2EAB-47AB-A045-C62B2CDACC29

[2] BC Methodology Manual, Reporting Regulations for Greenhouse Gas Reduction Act, Dec 2009, http://www.env.gov.bc.ca/cas/mitigation/ggrcta/reporting-regulation/pdf/methodology-manual.pdf

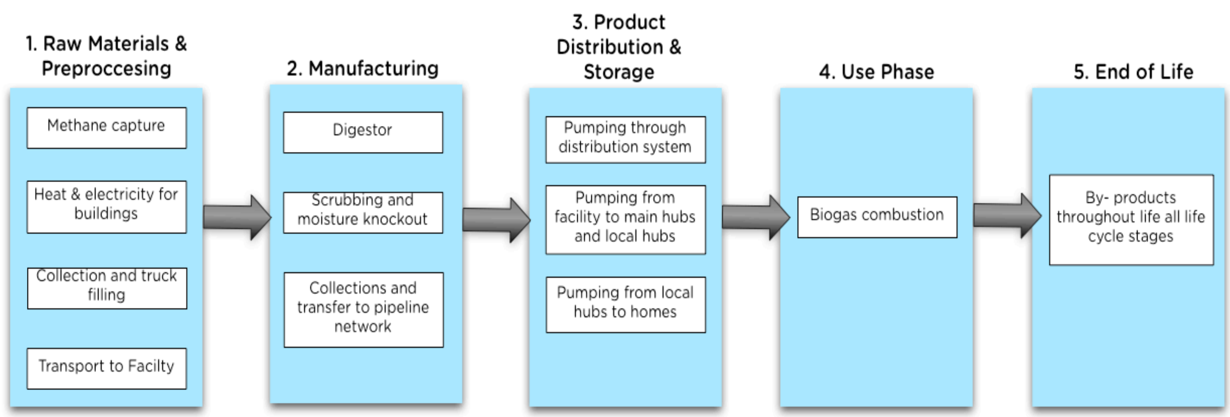
[3] http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/10_272_2009

3 Life Cycle Emissions from Biomethane

This section of the report examines the life cycle emissions of biomethane and provides insight into the impacts each life cycle stage will have on the overall GHG inventory. Section 3.1 provides a description of expected GHG emissions sources and sinks while Section 3.2 is a summary of findings from existing life cycle studies conducted on biomethane.

Figure 3 below illustrates the general life cycle stages associated with biomethane. Each of the five life cycle stages are labelled above the corresponding box.

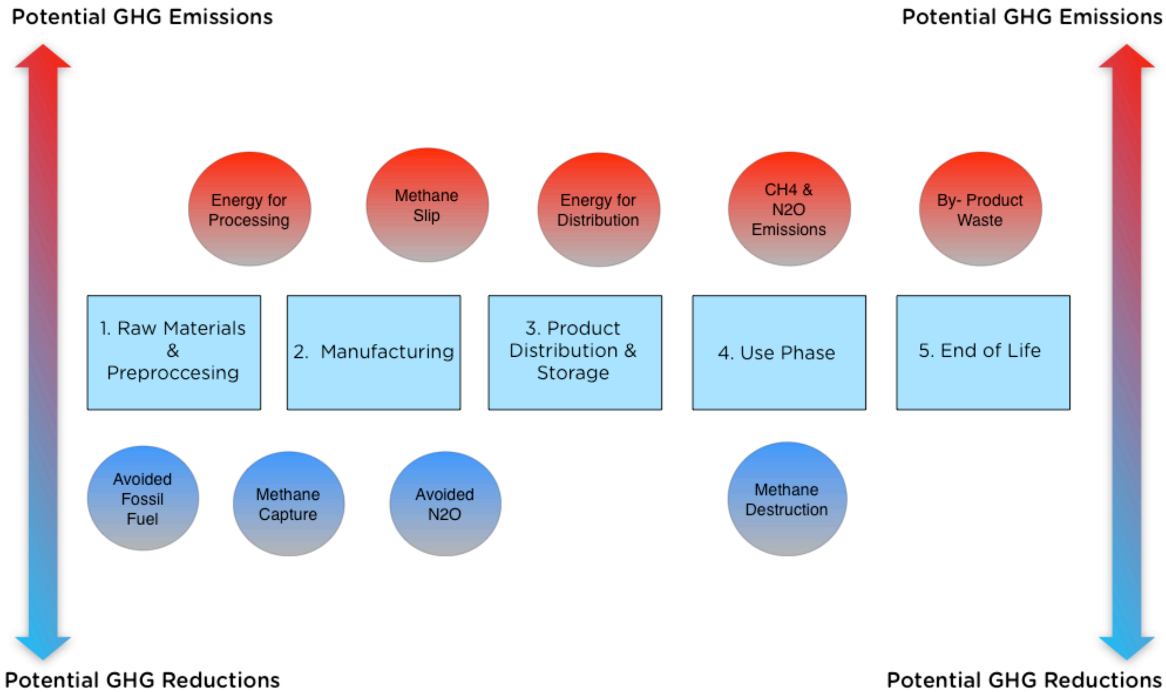
Figure 3: Process Map of Biomethane Life Cycle



3.1 GHG Sources and Reductions throughout Life Cycle

Throughout the life cycle of biomethane, there are both emissions sources and sinks that balance to create a net reduction in greenhouse gases when compared to natural gas as a fossil fuel. Figure 4 below illustrates these expected emissions and reductions in the life cycle of biomethane production. The circles in red above the life cycle stages illustrate GHG emission sources, while the blue circles underneath represent GHG sinks. Further explanation of GHG sources and sinks can be found in sections 3.1.1 and 3.1.2 respectively.

Figure 4: GHG Sources and Reductions from Biomethane Life Cycle



3.1.1 Life Cycle GHG Emission Sources from Biomethane

1. Energy Required for Processing

- Electricity, natural gas, diesel fuel or propane can be used in buildings and other facilities used to process and manufacture biomethane.
- Emissions associated with support equipment and vehicles used to move materials such as manure or landfill waste within a facility. Support equipment can also include wastewater pumps in the case of a wastewater treatment facility.

2. Methane Slip

- A small percentage of methane is lost in processing, transport and distribution, which can be referred to as fugitive emissions.
- For example, there may be inefficiencies and venting events that occur that result in leaked emissions from an anaerobic digester, or there may be fugitive emissions from a gas pipeline network.

3. Energy Required for Biomethane Transport distribution

- Fuel consumed for transportation can include fuel used in natural gas tanker trucks.
- Electricity usage consumed for distribution facilities and gas pipeline network pumps.

4. Methane and Nitrous Oxide Emissions from Combustion

- According to greenhouse gas accounting protocols, such as the WRI GHG Protocol, methane (CH_4) and nitrous oxide (N_2O) emissions are to be accounted for when combusting biomass.
- CH_4 and N_2O are not considered to be biogenic like CO_2. In other words, non-biogenic greenhouse gas emissions are not part of the natural carbon cycle.

5. By-Product Waste

- Waste created throughout the life cycle stages, such as wastewater, solid deposits and other organic material will result in methane emissions during decomposition that may not be completely captured by the biomethane facility.

3.1.2 Life Cycle GHG Sinks from Biomethane

1. Avoided Fossil Fuel

- Emissions from the combustion of natural gas are avoided when biomethane is used as a alternative fuel source. Because biomethane captures emissions from decomposing organic materials, the CO_2 emitted is considered to be part of the natural carbon cycle and no net increase in greenhouse gas emissions occur.
- In addition to replacing natural gas combustion emissions which occurs in the use phase, biomethane's cradle-to-gate life cycle also results in far fewer emissions than the life cycle of natural gas. Fossil fuel production includes extraction and processing of natural gas, which is avoided in the use of biomethane.

2. Methane Capture and Destruction

- While avoided fossil fuel emissions result from biomethane displacing natural gas, there are also emissions reductions simply from transforming methane into carbon dioxide. Methane capture and destruction takes advantage of the global warming potential (GWP) difference between the two gases. For example, destroying one tonne of methane is the equivalent of destroying 21 tonnes of carbon dioxide because methane has a greater effect on climate change than carbon dioxide does.
- Under baseline conditions, methane from organic waste would typically decompose anaerobically and release methane into the atmosphere in the natural world. Capturing this methane prevents it from contributing to climate change.

3. Nitrous Oxide Reduction

- Avoided nitrous oxide (N_2O) emissions from processing of biogas

3.2 Literature Review of Biomethane Life Cycle Assessment

Offsetters has conducted a literature review of existing research conducted on the greenhouse gas emissions associated with biomethane from landfill gas, wastewater treatment and anaerobic digester facilities. The following sections 3.2.1 to 3.2.3 detail the research findings for each biomethane type.

3.2.1 Landfill Gas to Liquefied Natural Gas Life Cycle Assessment

A study conducted by the California Air and Resources Board (CARB) examined the GHGs associated with the life cycle of landfill gas when converted into compressed natural gas (CNG). The CNG is used as an alternative to natural gas for vehicle fuel. Figure 5 below illustrates the pathway of CNG from landfill gas collection to fuel combustion, also referred to as 'well- to-wheel'. Table 4 provides a summary of the study and life cycle emissions.

Figure 5: Process Map of Landfill Gas to CNG

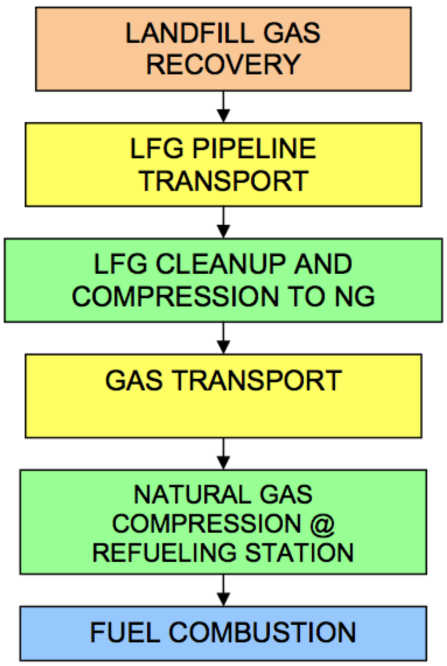


Table 4: Summary of CARB Landfill Gas Study

Study
California Environmental Protection Agency: Air Resources Board (CARB). Detailed California- modified GREET pathway for compressed natural gas (CNG) from landfill gas. Version 2.1. February 28, 2009.
Source
http://www.arb.ca.gov/fuels/lcfs/lcfs.htm#lca
Summary Points:

• 11.26 grams CO_2e of GHG emissions are generated for every MJ during the production and use of CNG in a passenger vehicle
• Emission sources in this study include:
  o Electricity consumption for landfill gas recovery, transport and compression and distribution
  o Tailpipe carbon dioxide, methane and nitrous oxide emissions
• Emission credits in this study include
  o A flare GHG credit of -64.65 gCO_2e per MJ has been included

3.2.2 Dairy Digester to Compressed Natural Gas Life Cycle Assessment

The California Air and Resources Board (CARB) also conducted a similar study on the life cycle of biogas converted from a dairy digester into compressed natural gas (CNG). The CNG is used as an alternative to natural gas for a vehicle. Figure 6 below illustrates the pathway of CNG from a dairy digester to fuel combustion, also referred to as 'well- to- wheel', provides a summary of the study and life cycle emissions.

Figure 6: Process Map of Dairy Digester to CNG

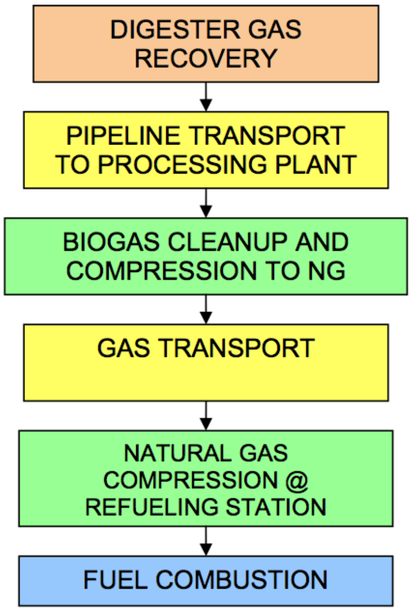


Table 5: Summary of CARB Dairy Digester Study

Study
California Environmental Protection Agency: Air Resources Board (CARB). Detailed California- modified GREET pathway for compressed natural gas (CNG) from dairy digester biogas. Version 1.0. July 20, 2009.
Source
http://www.arb.ca.gov/fuels/lcfs/lcfs.htm#lca
Summary Points:

• 13.45 grams CO_2e of GHG emissions are generated for every MJ produced and combusted in a passenger vehicle
• Emission sources in this study include:
    o Electricity consumption for digester biogas gas recovery, transport and compression and distribution
    o Tailpipe carbon, methane and nitrous oxide emissions
• Emission credits in this study include
    o A biogas GHG credit of -63.05 gCO_2e per MJ has been included based on the carbon content of the emitted biogas

3.2.3 Methane and Nitrous Oxide Emissions from Dairy Cattle Slurry

In this study published in the journal, *Agriculture, Ecosystems and Environment*, methane, nitrous oxide and ammonia emissions were measured during the storage and application of dairy cattle slurry. The study examined the impact of these emissions based on various treatment methods. In Table 6 below provides a summary of this article and the emission reductions associated with treating dairy cattle slurry through an anaerobic digester.

Table 6: Summary of Study on Dairy Cattle Slurry

Study
Methane, nitrous oxide and ammonia emissions during storage and after application of dairy cattle slurry and influence of slurry treatment. From *Agriculture, Ecosystems and Environment* 2006. Volume 112 (153-162).
Author
Amon, B., et al.
Summary Points:
• Untreated slurry emitted 92.4 kgCO_2e for every cubic metre from storage and field application. For slurry treated through anaero$_b$ic digestion, emissions were reduced to 37.9 kgCO_2e for every cubic metre.

3.2.4 Bioenergy vs. Fossil Fuel Emissions

In this study, the life cycle analysis of biomass and fossil fuel energy systems is conducted in order to compare overall greenhouse gas emissions. Emissions throughout the biomass and fossil fuel life cycle are taken into account. Table 7 below provides a summary of this article including the GHG reductions from using biogas from manure as an alternative to natural gas.

Table 7: Summary of Study Comparing Fossil Fuel to Bioenergy

Study
Greenhouse gas emissions of bioenergy from agriculture compared to fossil energy for heat and electricity supply. From Nutrient Cycling in Agroecosystems 2001. Volume 60 (267-273).
Author
G. Jungmeier & J. Spitzer
Summary Points:
• The life cycle emissions of biogas from cow, pig manure and co- digestion for combined heat and power plants (CHP) are negative ○ The GHG benefits from the use of by- products and from the avoidance of methane from manure storage are incorporated into the measurements • According to this study, using biogas from manure and co- digestion for CHP rather than natural gas, will reduce GHGs by between 129% and 286%.

4 GHG Benefits and Conclusion

During the life cycle of biomethane, opportunities for emission reductions include the following:

- Methane capture
- Methane destruction
- Avoided emissions from fossil fuel extraction and processing
- Avoided nitrous oxide emissions

Of these emission reductions, the most relevant savings come from methane capture and destruction. Additionally, as in the case of FortisBC's biomethane offering, there are emission reductions associated with the displacement or avoidance of fossil fuels. The reduction of nitrous oxide (N_2O) emissions is the most unknown and least likely to be quantified at this time.

4.1 Methane Capture and Destruction

Methane capture and destruction is the most common opportunity for realizing GHG emissions savings in biomethane production. These savings are generated by first installing a biogas control system which captures the methane emitting from organic waste. Then the methane is destroyed through combustion either by flaring or during it's end use application, either on-site or off-site.

The GHG reductions result from avoiding methane emissions associated with the organic material's baseline condition. Without the efforts of biomethane project, biomass is stored under anaerobic conditions and decomposes to release methane into the atmosphere. By capturing this biogas and combusting it to create carbon dioxide, the methane is transformed into a much less impactful greenhouse gas. Specifically, the global warming potential (GWP) of carbon dioxide is 1, while the GWP of Methane is 21.

4.2 Avoided Fossil Fuel Life Cycle Emissions

Biomethane is a clean alternative to non- renewable fossil fuels such as natural gas. In the natural gas pipeline network, each cubic meter of biomethane effectively prevents life cycle GHG emissions from being produced for the equivalent amount of natural gas. These life cycle emissions result from the extraction and processing of fossil fuel natural gas, including the production, refinement and storage of fossil fuels.

4.3 Conclusion

The benefits of using biomethane as a fuel source include:

- Prevention of naturally occurring methane from directly entering the atmosphere
- Lifecycle GHG emissions savings from the displacement of conventional natural gas
- No net increase in greenhouse gas emissions from combustion because biomethane is a carbon neutral energy source in BC

The FortisBC renewable natural gas program allows customers to achieve significant greenhouse gas savings and reduce their own carbon footprint.

OFFSETTERS

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Attachment 18.2

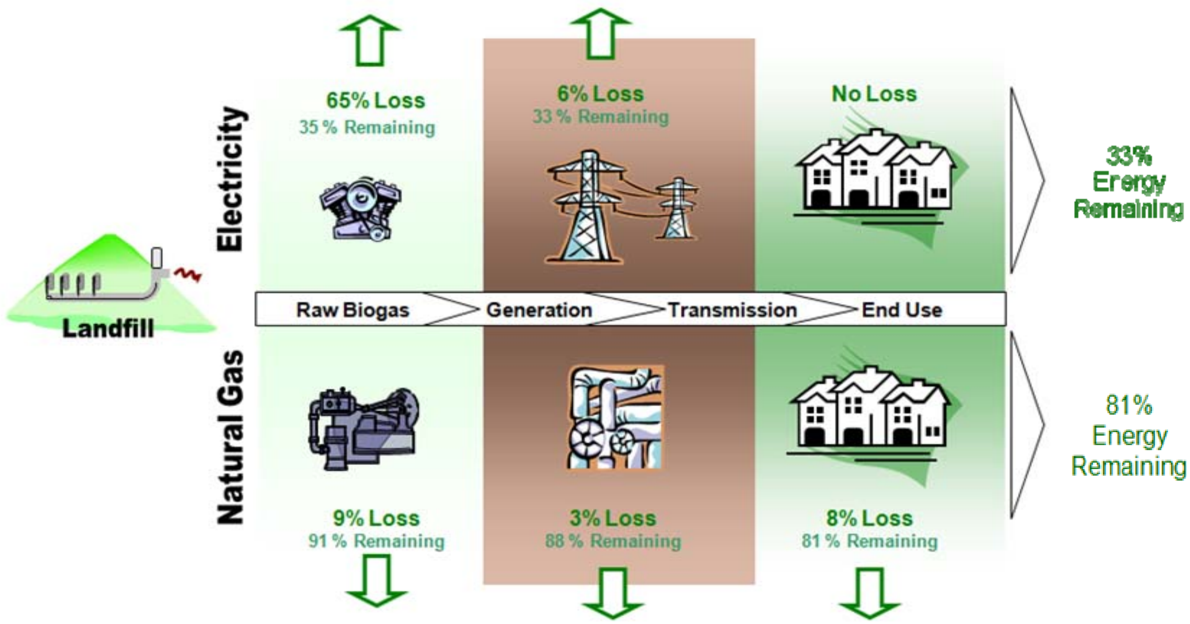
TERASEN GAS INC.

Biomethane Application

Volume 1 - Application

June 8, 2010

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 –

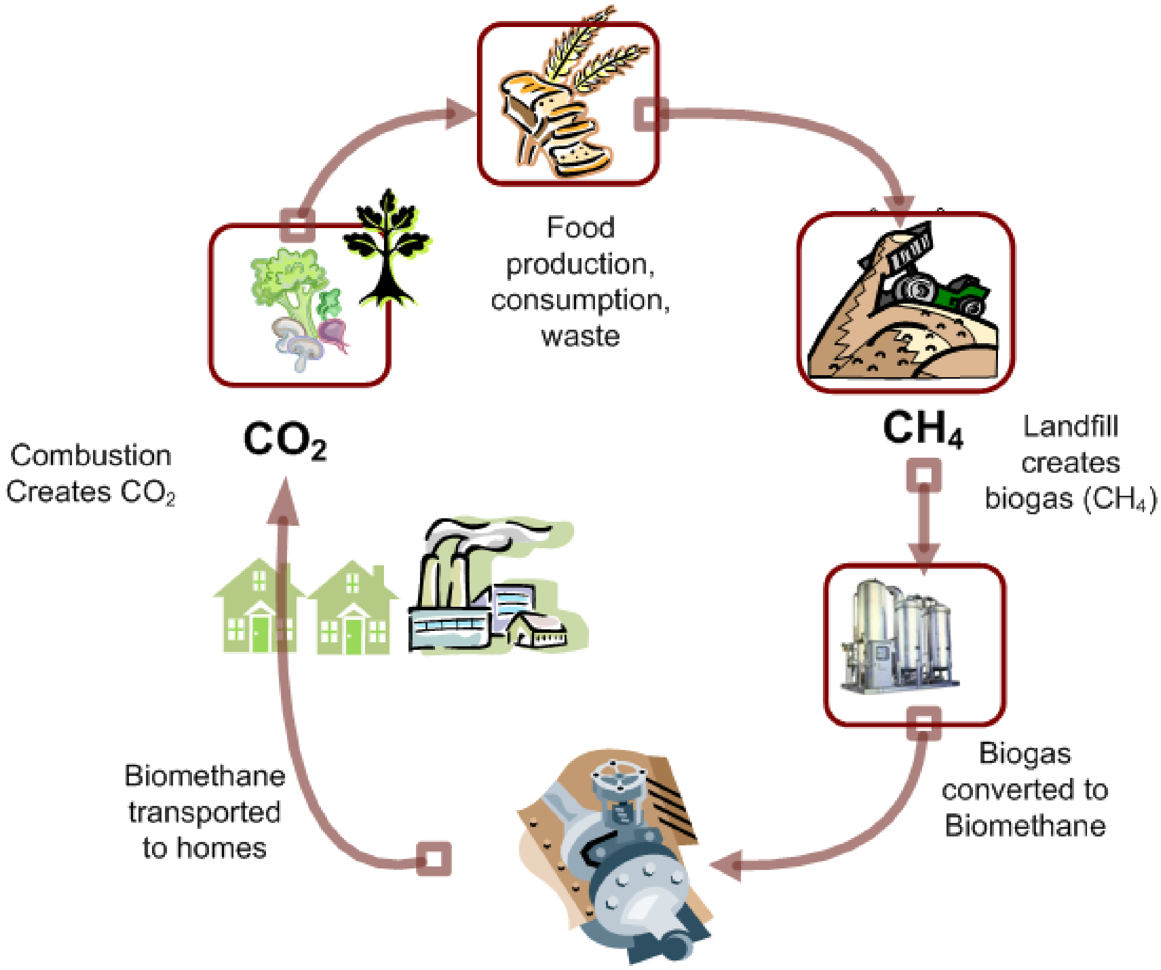
hence the name. Ultimately too much GHG emission will contribute to a warmer planet and climate change. For the purpose of this Application, the most relevant GHGs are carbon dioxide (CO_2) and methane (CH_4). More specifically, CO_2 and CH_4 that come from net carbon emitting sources – such as conventional 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



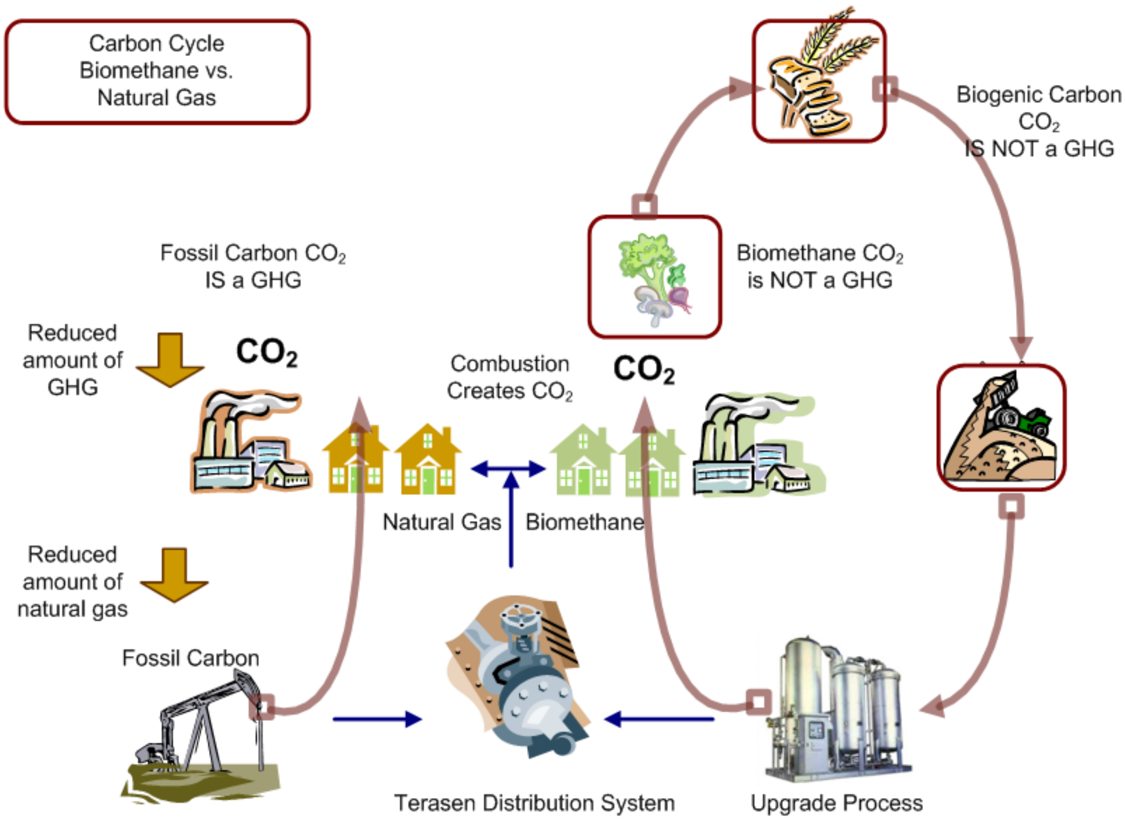
The carbon cycle is similar for other waste streams such as agricultural waste. Agricultural waste could either release methane directly into the atmosphere (if it is not carefully managed) or it can be aggregated in a digester. Once it is collected in a digester the agricultural waste would generate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

Attachment 18.3

20.0 Topic: GHG offsets

Reference: Exhibit B-2-1, Workshop Undertaking Response, GHG Offsets

"What follows is a discussion about carbon offsets, recognizing that this is an emerging market and much remains uncertain about the rules and regulations at this time."

"The creation of offsets and the potential value they create could help reduce the costs to customers who purchase Biomethane as proposed in Terasen Gas' Biomethane Application."

20.1 Please confirm that the fundamental environmental benefit of the proposed biomethane blend sales program and the two biomethane supply projects is the substitution of biomethane for 'conventional' (as defined) natural gas at the point of consumption (i.e., combustion) by the customer.

Response:

The environmental benefits can be created by both suppliers and customers of Biomethane. Suppliers can reduce emissions during the process of capturing Biomethane whereas customers can reduce emissions through consumption of the Biomethane in place of natural gas.

20.2 Please confirm that the program is not designed to, or intended to, provide participating customers with any marketable carbon offset.

Response:

On July 28th, 2010, Terasen Gas received a letter from the British Columbia Ministry of Finance regarding Terasen Gas' enquiry regarding the application of carbon tax on the sale of natural gas, specifically, biomethane. The Company is currently in discussion with the Ministry of Finance regarding the letter, and determining the appropriate next steps. The Company intends to file a response to this question by August 18th, 2010. The Company believes that this delay is required and appropriate, to enable the Company to address this question taking into account the most recent developments.

20.3 Please confirm that Terasen has filed no evidence regarding the carbon intensity of the production of either biomethane or 'conventional' natural gas. In this regard, please confirm that the statement, "The production and consumption of Biomethane is carbon-neutral..." [underline added] on p.16 of the Application is not supported.

Response:

Please see the response to CEC IR 1.1.1.

20.4 In terms of the possibility of the counterparties to the two energy supply contracts being able to acquire marketable carbon offsets related to their production of biogas or biomethane, please confirm that

20.4.1 pursuant to the terms of these specific energy supply contracts property in any environmental attributes is held by the producer not Terasen,

Response:

This response is provided to the Commission confidentially under a separate cover due to commercially sensitive information.

20.4.2 in the case of the landfill biogas project it would appear unlikely at face value that the producer would be eligible for marketable carbon offsets, because the collection of landfill biogas is required by law and so the project has no "additionality" beyond "business as usual,"

Response:

Until the rules have been fully defined regarding carbon offsets, TGI is unable to confirm the question raised.

However, TGI can confirm that the responsibility in creating offsets, having them validated, and qualifying them for sale resides with the Biogas producer. Over time, if the producer is able to qualify the project to show that an offset of this type has been created, then they can claim ownership and therefore retain the value of this type of offset.

Note that it is TGI's understanding that the legal requirement regarding collection of landfill biogas is dependent on the amount of waste in place and the amount deposited on an annual basis so it may be the case that some landfill biogas collection operations do qualify as additional.

20.4.3 in the case of the agricultural waste biogas project, as there is at present no legal requirement for the collection of agricultural methane there may be a basis for the producer to acquire marketable carbon offsets due to the fact that the project prevents the venting of raw methane if and when a carbon offsets exchange system is established, but the costs and benefits of these potential carbon offsets are entirely to the account of the producer, not Terasen or Terasen's customers, because the price terms of the ESC contemplate that the producer retains any environmental attributes, and

Response:

The ownership of offsets, if qualified and created, resides with the producer for the projects contained in this Application. The costs associated with obtaining carbon offsets for the production also reside with the producer. TGI is not in a position to comment on the likelihood for producers to qualify for offsets.

20.4.4 when Terasen says that "Over time, if the producer is able to qualify the project through third-party certification to show that an offset of this type has been created, the value of this offset would be incorporated into the producers revenue streams and therefore reduce the sale price TGI negotiates with the producers to pay for Biogas or Biomethane," Terasen is referring to future energy supply contracts, not to the two ESCs in the current application.

Response:

Correct. As regulations become more clearly defined and implemented and the role of offsets become more established in this market, TGI and producers will be in a better position to determine how the value of offsets can be reflected in the purchase or sales price of Biomethane.

20.5 Terasen's discussion of the possibility of carbon offsets arising from the biomethane blend program and projects addresses both suppliers and customers. Please confirm that Terasen's discussion is not intended to imply that that there could be any double counting of carbon offsets.

Response:

It is not the intention of Terasen Gas that there should be any double counting of carbon offsets, but we do acknowledge that there can be a potential for offsets from both suppliers and customers depending on how regulations unfold. Terasen Gas is not a decision maker with respect to this matter and therefore will only need to act within the boundaries of such regulations.

20.6 Terasen discusses its request for an exemption from the provincial carbon tax on the biomethane they purchase under the proposed program. Please confirm that:

20.6.1 the proposed exemption would apply only to the 10% biomethane portion of the blended service offering, and

Response:

Confirmed.

20.6.2 an exemption from the carbon tax for the purchase of biomethane is not to be confused with a carbon offset.

Response:

Confirmed.

20.7 Please confirm that Terasen will not market the biomethane blend program as in any way providing a "carbon offset."

Response:

By offering Biomethane, Terasen Gas has the intention to offer its customers a renewable energy choice, which will reduce GHG emissions. The outcome of how the offsets can be recognized as a result of customers' consumption of Biomethane remains uncertain due to government regulations. Although Terasen Gas needs to act within the boundaries of regulations imposed by the government, Terasen Gas will try its best to bring value for its customers whether that is in the form of a carbon tax exemption, creating an offset for sale, or both.

1. Reference: Exhibit B-1, Page 2

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

1.1. Why does Terasen discuss these sources of renewable biomethane as carbon-neutral?

Response:

TGI refers to biomethane as carbon-neutral since it is from a biogenic source rather than a fossil fuel-based source. Since biogas is a natural product arising from the decomposition of organic matter the carbon in biogas is part of the natural carbon cycle and does not add new carbon to the atmosphere in the way that burning natural gas or other fossil fuels would. This is discussed in more detail in Sections 2.7.2 and 2.7.3 of the Application (Exhibit B-1, pages 17 to 20).

1.2. Is it not the case that absent Terasen's capture, processing and use of the biomethane in its natural gas distribution system the gas would have been released into the atmosphere as methane instead of as carbon dioxide as will be the case after Terasen's customer's use of the gas?

Response:

It is the case that the biogas capturing and upgrading processes in TGI's biomethane program will result in some avoidance of higher-GHG methane releases into the atmosphere. However not all the biogas capture and upgrading to biomethane will cause incremental avoidance of fugitive methane emissions. In some situations, such as at landfills, biogas capture has been already mandated by provincial government regulation, so adding upgrading equipment to convert the raw biogas to biomethane for pipeline injection does not result in additional avoidance of methane emissions. In agricultural situations some emissions would be in the form of methane but other emissions from farming operations occur from aerobic (rather than anaerobic) decomposition of organic matter, such as for example, when manure is spread on a field, and the resulting emissions are in the form of carbon dioxide rather than methane. The complexities related to GHG emissions at biogas sources of supply and GHG reductions resulting from biogas capture were discussed in Exhibit B-2-1, a response to an undertaking from the June 24, 2010 Workshop dealing with carbon offsets. At pages 3 and 4 of Exhibit B-2-1, TGI made the following statement:

Tom A. Loski
Chief Regulatory Officer

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Regulatory Affairs Correspondence
Email: regulatory.affairs@terasengas.com

August 17, 2010

BC Sustainable Energy Association
5-4217 Glanford Avenue
Victoria, BC
V8Z 4B9

Attention: Thomas Hackney, Director

Dear Mr. Hackney:

Re: Terasen Gas Inc. ("Terasen Gas" or the "Company")
Application for Approval of Biomethane Service Offering and Supporting Business Model, for the Approval of the Salmon Arm Biomethane Project and for the Approval of the Catalyst Biomethane Project (the "Application")

Response to the BC Sustainable Energy Association ("BCSEA") Information Request ("IR") No. 1, Question 20.2

On June 8, 2010, Terasen Gas filed the Application as referenced above. In accordance with Commission Order No. G-109-10 setting out the Regulatory Timetable for the review of the Application, Terasen Gas submitted its response to BCSEA IR No. 1 on August 6, 2010.

In order to take into account discussions with the Ministry of Finance and any recent developments, Terasen Gas committed to responding to IRs relating to the application of carbon tax by August 18, 2010. Accordingly, Terasen Gas respectfully submits the attached response to BCSEA IR 1.20.2.

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

Attachment

cc (e-mail only): Erica Hamilton, Commission Secretary
Registered Parties

20.0 Topic: GHG offsets

Reference: Exhibit B-2-1, Workshop Undertaking Response, GHG Offsets

"What follows is a discussion about carbon offsets, recognizing that this is an emerging market and much remains uncertain about the rules and regulations at this time."

"The creation of offsets and the potential value they create could help reduce the costs to customers who purchase Biomethane as proposed in Terasen Gas' Biomethane Application."

20.2 Please confirm that the program is not designed to, or intended to, provide participating customers with any marketable carbon offset.

Response:

Confirmed.

The intent of the program is not to sell customers a marketable carbon offset, rather a renewable energy product which in turn, reduces their carbon footprint.

The current regulation is unclear about carbon offset opportunities for customers. As indicated in the Response to Workshop Undertaking, dated July 8, 2010, TGI may look at creating offsets on the customers' behalf in the future as a result of the offset created by consuming Biomethane in place of natural gas. However, this would involve third party validation and verification and the establishment of accepted protocols for these projects which have not been defined at this time and would be more appropriate if TGI were to develop a carbon offset program, rather than the proposed renewable energy-based program. By displacing natural gas with Biomethane in end-use applications, all else being equal, there is a net reduction in the amount of GHGs in the atmosphere which is the green attribute that customers would be paying for under the proposed program.

Seeking to maximize value for our customers, the Company has applied to the British Columbia Ministry of Finance for confirmation that Biomethane as described in the Application will be exempt from Carbon Tax. On July 28th, 2010 Terasen Gas received a letter from the British Columbia Ministry of Finance, found in Attachment 20.2, confirming that combustion of both Biogas and Biomethane are activities exempt from the Carbon Tax. The Company had hoped to be able to provide a clear answer at this time as to whether or not the proposed Green Gas program will allow customers to be exempted from paying Carbon Tax on the portion of their purchased gas that is Biomethane. The Company is still in ongoing discussions with the British Columbia Ministry of Finance to clarify a point of ambiguity within the letter received on July 28th, 2010. In their letter, the Ministry of Finance stated that:

Terasen is proposing that carbon tax is invoiced and collected from customers based on a standard 90% natural gas/10% biomethane blend, when in fact the blend could vary. Under Section 13 of the CTA (Carbon Tax Act), Terasen is obligated to determine the amount of natural gas in the blend and invoice and collect carbon tax from purchasers accordingly. As biomethane is considered a non-taxable substance, no reference to the application/exemption of carbon tax on the biomethane in the blend is required on the invoice.

Terasen Gas believes that this statement is based on a misunderstanding of the concept of notional delivery, and will propose to the Ministry of Finance that we are in fact ensuring the integrity of the 90%/10% blend through our extensive monitoring of the Biomethane injected into the system and the Biomethane purchased by our customers to displace 10% of their natural gas consumption.

The Company is of the opinion that the likelihood of agreement between the parties is strong. The transportation and delivery of Natural Gas across North America is premised on all participant's acceptance of the concept of notional delivery through displacement, and the delivery of Biomethane to Green Gas customers through the existing gas distribution system will work no differently.

For taxation purposes, a comparable example is that of marketer gas moving through the existing distribution system. Marketers deliver their gas to supply hubs to displace gas the Company would otherwise have delivered to those supply hubs. Terasen Gas then notionally delivers this gas to customers of marketers. Since, the Company does not track molecules across our system, there is no way of knowing if the marketer gas is the same gas physically received by the customer, but the customer who purchased that gas from the marketer is billed for the gas they chose to purchase and consume at the agreed to price, and taxes are applied accordingly, even if the marketer gas was in actual fact delivered to a Terasen Gas commodity customer, or a customer of a different marketer. Based on this precedent, the Company believes that the existing gas tracking mechanisms will allow for the level of surety that the Ministry of Finance needs in order to allow Green Gas customers to be exempted from the Carbon Tax on the portion of their purchased gas that is Biomethane.

Terasen Gas believes that the measurement process proposed in the Application will provide sufficient documentation as to make the Biomethane portion of gas purchased through the Green Gas program exempt from Carbon Tax, and is seeking to clarify agreement on that point with the Ministry of Finance.

As soon as the Company has certainty on this issue, TGI will provide written documentation to the Commission and all registered interveners. Regardless of the outcome, Terasen Gas will work with the Ministry of Finance to ensure that we have done everything we can to protect the best interests of our customers.

BRITISH COLUMBIA
The Best Place on Earth

July 28, 2010 228665

Mark Worrall, CA
Associate Partner, Indirect Tax
KPMG LLP
Chartered Accountants
PO Box 10426
777 Dunsmuir Street
Vancouver, BC V7Y 1K3

Dear Mr. Worrall,

Thank you for your letter dated March 30, 2010, regarding the application of carbon tax on the sale of natural gas by your client Terasen Gas Inc. (Terasen). I apologize for the delay in responding to your ruling request. The Ministry has now completed the review of the facts you have presented.

You have requested 3 rulings that confirm the following:

a) Terasen is not required to pay security under the Carbon Tax Act (CTA) in respect of its purchase of biogas and biomethane.
b) Terasen is not required to collect carbon tax on sales of natural gas to customers purchasing the biomethane product from Terasen based on the proportion of biomethane price paid by the customer.
c) Terasen's proposed method of disclosing the exemption from carbon tax to biomethane customers are appropriate.

In order to issue the rulings, the Ministry considered whether "biogas" and "biomethane" are substances which are intended to be:

- subject to security or tax
- not subject to security or tax (non-taxable substance), or
- exempt from security or tax

under the CTA.

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Ministry of Finance

Policy and Legislation Branch

Mailing Address:
2nd Floor - 1810 Blanshard Street
Victoria, BC V8T 4J1

Telephone: 250 356-0573
Facsimile: 250 356-7348

The ministry has determined that biogas and biomethane are not subject to security or tax under the CTA. Based on your explanation of how biogas and biomethane are derived, the Ministry does not consider that these substances are "natural gas" as it is currently defined under the CTA. And, as biogas and biomethane are not themselves substances that are included in Schedule 1 of the Act they not considered "fuel" for the purposes of the CTA. The security and tax scheme under the CTA is such that only substances that fall into the definition of "fuel" are subject to payment of security or tax.

> **"fuel"** means a substance set out in column 2 of the Table in Schedule 1 but does not include
> (a) methanol produced from biomass, and
> (b) methane produced by waste in a landfill.
>
> **"natural gas"** means natural gas, whether or not the natural gas
> (a) occurs naturally or results from processing, or
> (b) contains gas liquids,
> but does not include refinery gas.

As biomethane is considered a non-taxable substance, section 13(1) of the Act would apply to the application of carbon tax on the biomethane/natural gas blend.

Section 13 reads:

> **Calculation of tax for blends or mixtures**
> 13 (1) If a mixture or blend is composed of one or both of the following combinations:
> (a) one or more fuels, with or without one or more non-taxable substances or items;
> (b) one or more combustibles, with or without one or more non-taxable substances or items,
>
> the amount of tax payable for a fuel or combustible in the mixture or blend is to be determined by multiplying the rate of tax determined under the applicable provision of this Act by the amount of that fuel or combustible in the mixture or blend.
>
> (2) Subsection (1) does not apply to a prescribed fuel, combustible, substance or item or in prescribed circumstances.
> (3) Subject to subsection (4), if a mixture or blend includes a prescribed fuel, combustible, substance or item referred to in subsection (2), the amount of tax payable on the mixture or blend is the amount determined in accordance with the regulations.
> (4) If a substance or item is not taxable under this Act, the regulations may deem the substance or item to be taxable at a prescribed rate if the substance or item is included in a mixture or blend but comprises less than the prescribed percentage of the mixture or blend.

Fact #10, 11 and 14 in your correspondence appear to state that Terasen is proposing that carbon tax is invoiced and collected from customers based on a standard 90% natural gas/10% biomethane blend, when in fact the actual content of biomethane in the blend could vary. Under

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section 13 of the CTA, Terasen is obligated to determine the amount of natural gas in the blend and invoice and collect carbon tax from purchasers accordingly. As biomethane is considered a non-taxable substance, no reference to the application/exemption of carbon tax on the biomethane in the blend is required on the invoice.

In your correspondence you reference a purification process that is undertaken to convert biogas into pipeline quality biomethane. If this process is similar to the processing of natural gas which includes the removal and combustion of acid gases (H_2S and CO_2); then the combustion of the acid gases is not subject to carbon tax. However, any "fuel" used to lift, or assist, in the combustion of acid gases is subject to carbon tax and should be included in the self-assessed amount on Terasen's tax return.

I trust this information adequately responds to your enquires. If you would like to discuss this response or require further clarification, please contact me directly at 250- 387-4174.

Yours truly,

M. Kimpton

Mary Kimpton
Director
Policy and Legislation Branch
Ministry of Finance