



July 31, 2007

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

Attention: Mr. R.J. Pellatt, Commission Secretary

Dear Sir:

**Re: Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI")
(collectively the "Terasen Utilities" or the "Companies")
System Extension and Customer Connection Policies Review Application (the
"Application")**

The British Columbia Utilities Commission ("BCUC" or the "Commission") by Order No. 161-06 and Reasons for Decision approved the TGVI 2006 Negotiated Settlement Update wherein TGVI suggested that a review of its system extension and customer attachment and connection policies ("the Policies") was warranted. TGVI stated that due to changes in the market place since the last System Extension Test ("SET") Guidelines, it intended to file a review of the Policies which would consider other external realities and be broader than a simple Main Extension ("MX") test review.

By Order No. G-160-06 and Reasons for Decision, the Commission approved the TGI 2006 Annual Review and Mid-Term Settlement Review wherein the Commission agreed that TGI should conduct a review of its system extension and customer connection policies including the MX test in 2007 in conjunction with TGVI for submission by the end of the second quarter of 2007.

On June 28, 2007, the Terasen Utilities filed an application with the Commission for approval to delay the submission of its system extension and customer connection policies review due to staffing resource constraints, as well as to review TGW's Policies in order to make specific recommendations for TGW in addition to TGI and TGVI. By Letter No. L-61-07, the Commission agreed that a submission of a consolidated application was desirable and directed the Terasen Utilities to submit the application no later than July 31, 2007.

Currently, TGW uses the MX test and connection policies that were used by TGVI prior to 2006. After further consideration and in light of the introduction of natural gas to the Whistler area during the latter half of 2008, TGW is of the view that it would be reasonable to retain the current policy while it remains a propane system, and bring forth an application to review its Policies after the successful conversion and implementation of the natural gas system.

The attached Application, therefore, is the System Extension and Customer Connection Policies Review for TGI and TGVI. The Application requests approval for changes to the respective Policies to be effective January 1, 2008. TGI and TGVI believe that these changes will send appropriate market signals to customers, simplify the test across these two utilities and promote fair and equal treatment of customers. Lastly the changes are designed to support the Companies' ability to contribute to the goals and objectives of the BC Energy Plan and promote

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the responsible use of natural gas as a method to achieve energy efficiency and optimal use of resources within the broader energy market.

Accordingly, with due consideration to the regulatory efficiencies of a written hearing process for all parties involved, TGI and TGVl respectfully submit that the most appropriate review process for this Application is by way of a written process, and request a review process be established that would allow a decision on this Application by the middle of October 2007. In support of this request, the following schedule is proposed by TGI and TGVl for a written hearing process.

Proposed Regulatory Timetable:

<u>Action</u>	<u>Date (2007)</u>
Intervenor Registration	Monday, August 13
BCUC and Intervenor Information Requests	Wednesday, August 15
TGVl-TGI Response Information Requests	Friday, September 7
TGVl-TGI Final Argument Submission	Friday, September 14
Intervenor Argument Submission	Friday, September 21
TGVl-TGI Reply Argument Submission	Friday, September 28

At the completion of the review of this Application and in accordance with receipt of a Commission decision, TGI and TGVl will submit the affected Tariff pages, for each utility, for endorsement.

If you have any questions related to this information, please do not hesitate to contact Jason Wolfe at (604) 592-7516.

Yours very truly,

TERASEN GAS INC.

Original signed by: Douglas Stout

For: Scott A. Thomson

Attachments

- cc (e-mail only)
- Registered Intervenor/Parties to:
- TGI 2006 Annual Review and 2004-2007 Multi-Year PBR Settlement
 - TGVl 2006 Settlement Update and TGVl 2006-7 Revenue Requirement and Multi Year Negotiated Settlement

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1 Introduction

This is an application by Terasen Gas Inc. (“TGI”) and Terasen Gas (Vancouver Island) Inc. (“TGVI”) (collectively the “Terasen Utilities” or the “Companies”) for changes to their respective system extension and customer connection and attachment policies to be effective January 1, 2008. The Companies believe that these changes will help to reduce barriers and send the appropriate market signals to customers that are making decisions on using the right fuel, for the right activity at the right time. The changes will simplify the current tests and policies thereby making it easier to understand and to economically connect to the system of each of the Companies. These changes will promote the responsible use of natural gas as a method to achieve energy efficiency and optimal use of resources within the broader energy market, which the Companies believe is consistent with the objectives of the 2007 BC Energy Plan – A Vision for Clean Energy Leadership (the “Energy Plan”) released by the Ministry of Energy, Mines and Petroleum Resources in the spring of 2007.

There has been a significant change in the business environment in which the Terasen Utilities operate since the existing customer connection policies were put in place in the mid-1990s. At that time natural gas had a significant cost advantage to other heating fuels, including electricity, and generally customers were economically motivated to choose natural gas as their fuel choice regardless of the connection fees that were in place. In today’s environment natural gas’ competitive position has eroded and connection costs have more of an influence in the fuel choice being made by developers and home owners. The Terasen Utilities believe that the signals created have resulted in sub-optimal fuel choices and that changes are required.

In British Columbia (“BC”) and elsewhere in North America, natural gas and electricity compete as the energy source for space and water heating. BC is fortunate to have a large supply of low-cost hydro electric generation. However, in recent years the supply demand balance become increasingly constrained. The cost of adding new electricity supply and associated infrastructure is significantly higher than historic levels and will impact the rates of all electric customers in the province. The Terasen Utilities believe that this impact can

be mitigated through policies that send more appropriate price signals to promote the use of natural gas for the appropriate applications.

The BC Energy Plan states that “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”¹. The Companies believe that, clearly, electricity is the right energy choice for lighting, computers, fans, refrigerators televisions and other small household appliances. The Companies also believe electricity is seldom the right energy form for space and water heating, cooking and drying clothes. If BC Hydro is to meet its goals under the BC Energy Plan, it must conserve energy. The Terasen Utilities are of the view that greater use of alternative energy forms, including natural gas, for space and water heating, cooking and clothes drying, will help BC Hydro in achieving these goals.

This Application seeks approval of changes to the standard fees and charges associated with new customer connections and to the Main Extension (“MX”) tests used to determine the requirement for customer contributions in aid of construction as follows:

- In the case of new customers connecting to existing mains, the proposed changes to fees and charges include the elimination of the minimum contribution Service Line Installation Fee (“SLIF”) and revision of the Service Line Cost Allowance (“SLCA”) to reflect current costs and expected consumption levels and to provide incentives, or eliminate disincentives, to install high efficiency gas appliances; and
- In the case of new mains and extensions, the Companies propose to continue the current TGI MX test methodology and to eliminate the SLIF and the SLCA. In addition, the Companies are proposing that the thresholds that must be met under the current MX test be modified. Under the current policy, the MX test is applied to each individual main extension to determine if there is a requirement for a customer contribution. As part of this Application the Companies are proposing that the minimum threshold be applied on an aggregate basis across all main extensions performed in any one year, which consequently will allow a lower threshold for individual extensions. The overall objective of these proposed changes is to send

¹ Energy Plan, page 21

appropriate signals to new customers when connecting to the natural gas system, while ensuring that they pay their fair share of incremental costs and that there are no undue impacts to existing customers.

2 Connection and Attachment Policy Objectives

The traditional regulatory approach to reviewing connection policies is similar to that of cost of service methodology. Specifically, system extension and connection tests and policies should:

- Promote fair and equitable treatment of customers and avoid undue discrimination;
- Send proper price signals;
- Be simple and easy to understand and implement; and
- Promote economic efficiency.

The Companies believe that as a result of the current economic climate, and specifically the release of the BC Energy Plan, the connection and attachment policies should help meet societal and governmental policy and objectives, including promoting energy efficiency and conservation and also encourage the optimal consumer energy mix.

The Energy Plan is “a made in BC solution to the common global challenge of ensuring a secure, reliable supply of affordable energy in an environmentally responsible way”². The document outlines 55 policy actions to help BC achieve this goal. The Terasen Utilities are supportive of the Energy Plan and believe that all energy utilities can and should play an integral role in helping BC meet and exceed the goals as set out in the Energy Plan.

The Terasen Utilities see a number of policy actions for which achievement of their objectives will be dependent on changes in the approach to customer connection and attachment activities for both gas and electric utilities:

² Energy Plan, page 2

- Policy Action #2, states “Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia”³. This action further states that “some programs, such as targeting household space and water heating, may not be justified on the basis of either electricity savings or gas savings alone. However, a coordinated effort may be cost-effective”.
- Policy Action #3 “Encourage[s] utilities to pursue cost effective and competitive demand side management opportunities”. The action further states that “Energy efficiency is a critical piece of all BC utility resource plans”⁴.
- Policy Action # 4 “Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation”. The action further states that utilities are encouraged to “explore, develop and propose to the Commission additional innovative rate designs that encourage efficiency [and include] tariffs focused on promoting energy efficient new construction...”⁵.
- Policy Action # 24 states, “A policy action of The BC Energy Plan is to review the BC Utilities Commission’s role in considering social, environmental and economic costs and benefits as a part of its regulatory framework”⁶.

The Companies believe that the changes requested in this Application are consistent with these Energy Plan policy actions. More specifically the Companies’ objectives in this Application are as follows:

1. Signal better value for customers wishing to attach to the system;
2. Ensure that the system extension test and policies measure the right factors, be simple to understand and administer with results that send the appropriate economic signal to the customer; and
3. Encourage energy conservation through the test and attachment policies; and
4. Encourage the “right fuel” choice. The Company believes that natural gas is an appropriate fuel for space and water heating applications and that the connection policies and tests should send the appropriate signal to customers for these energy uses.

³ Energy Plan – Energy Conservation and Efficiency Policies, page 1

⁴ Energy Plan – Energy Conservation and Efficiency Policies, page 3

⁵ Energy Plan – Energy Conservation and Efficiency Policies, page 4

⁶ Energy Plan – Energy Conservation and Efficiency Policies, page 6

The Companies are also undertaking other initiatives that combine to align utility activities and customer choices with Energy Plan policies on efficiency and innovation. For example, BCUC Order No. G-65-07 (June 2007) approving amendments to TGI's Tariff to allow thermal energy metering on a pilot project basis is an important initiative to help promote the efficient use and conservation of energy in multi-family dwellings. If the pilot project is successful and can be rolled out across service regions, this metering technology represents another opportunity to send appropriate economic signals to both end-users and the development community.

Further, Demand Side Management ("DSM") programming for both TGVI and TGI beyond the 2007 – 2008 heating season is expected to include a mix of both energy conservation and efficient load building programs. These programs will help to encourage the right energy or fuel to be used for the right application at the right time and to promote the most efficient and effective use of all existing and new energy infrastructure in BC.

TGI and TGVI are also strongly supportive of the Energy Plan directive for utilities in BC to work together cooperatively towards Energy Plan goals. For the Companies, pursuing cost-effective DSM initiatives, developing innovative rate designs (such as the thermal metering initiative) and working cooperatively with other utilities and energy industry participants represent a broad-based multi-faceted approach to achieving Energy Plan objectives.

3 Review and Analysis

3.1 BCUC Utility System Extension Guidelines

In 1995 and 1996 the Commission conducted a generic review of system extension policies for gas and electric utilities in British Columbia. The review was to look broadly at the system extension policies and determine if "opportunities existed to improve the fairness and efficiency of these policies". Following this review, the Commission issued the Utility System Extension Guidelines (the "SET Guidelines") in September 1996. In summary, the SET Guidelines recommended that system extensions be based on an incremental analysis using a discounted cash flow ("DCF") methodology. The analysis was to take into account

the incremental costs and benefits associated with a particular system extension over a period long enough to consider the full impact of the extension. The Commission also recommended that, as a general principle, the costs of system extensions be allocated to those customers who cause them.

The Companies believe that the general intent of the SET Guidelines is for utilities to have extension policies in place which provide a fair balancing of the interests of existing customers with the interests of new customers. A principle objective is that revenues from new extensions should at a minimum cover the incremental costs imposed on the system by those extensions such that new customers do not negatively impact existing customers.

Though the SET Guidelines made recommendations as to the methodologies preferred by the Commission for evaluating system extensions there was also room for flexibility in some matters, and the potential for adoption of other methodologies where appropriate. With respect to system improvements, for example, the SET Guidelines allowed for them to be left out of the analysis if the cost and administrative burden of identifying them were too great. The Commission also believed that estimates for actual construction costs should be as accurate as possible without adding substantially to the workload and administration. With respect to incremental maintenance and overhead costs, these were to be added to the test so long as the administrative costs did not exceed the benefit of determining those costs.

The Commission also noted that connection charges should “send an appropriate signal about the net social cost of less efficient energy usage”⁷.

3.2 Other Utilities

The Terasen Utilities conducted research with regard to other gas and electric utilities’ attachment and connection policies in order to achieve a better understanding of how these policies and programs work, and how effective they might be in the current marketplace. Research was conducted on four different natural gas utilities and two electric utilities.

⁷ Utility System Extension Test Guidelines, page 23

All utilities examined have a standard main extension policy and test, although the policy and test of each utility surveyed differs in methodologies. A detailed description of each utility's main extension and service line attachment policy and procedure, together with additional information, is included in Appendix 1. The principal methodology for each utility is summarized below:

- The test of Atco Gas Inc. is based upon a principle of providing non-discriminatory service rather than any concern of subsidization of new customers by current customers. The MX policy is to offer a main extension free of charge if the applicant's premise is within a municipality that has a franchise agreement with the utility. If the customer is not within a municipality and the main extension is less than 50 meters, the extension is provided free. If the extension is more than 50 meters the customer pays the difference between the costs and the revenue expected in the first three years.
- Avista Utilities Washington and Avista Utilities Oregon (collectively the Avista Utilities) utilize a revenue and cost analysis in order to determine if the main extension can be provided free of charge to the new customers. The Avista Utilities will provide a main extension at no cost if the annual revenue is not less than one third of the direct main extension cost. For Avista Washington, the Gas Extension Policy also includes service line attachment costs. For Avista Oregon, they will install up to 40 feet of service line free of charge.
- The Northwest Natural Utilities utilize a simple revenue and cost analysis to determine what contribution, if any, is necessary from the customer. Northwest Natural will install a main free of charge as long as the direct capital costs do not exceed the revenue expected in the first five years. Northwest Natural confirmed that most applications for main extensions and service lines pass, and very rarely does a customer need to make a contribution.
- Enbridge Gas Distribution Inc. ("Enbridge") performs a 40 year discounted cash flow test calculated on each main extension. Individual main extensions must have a profitability index of 0.80 or greater. Enbridge requires an aggregate profitability index 1.0 or greater for main extensions completed within a one year period. Enbridge will install a service line free of charge up to 30 meters from the property line.

- FortisBC charges new customers for the costs of a distribution extension (excluding the cost of transformers, service drops and meters). There is a service connection charge of \$200 for single phase, and an additional charge of \$3 per ampere above 100 amperes.
- BC Hydro's current SET employs a DCF methodology that considers incremental capital and operating costs, and the expected revenues from an extension. Since it is based on an incremental DCF methodology, BC Hydro's current SET, while quite complex, is consistent in principle with the Commission recommendations in the 1996 SET Guidelines. However, BC Hydro has not kept certain SET input factors, such as the incremental cost of electricity, up to date, so the expected price signals of incremental cash flow analysis have not been consistently conveyed to applicants for system extensions.

BC Hydro has applied for changes to its SET as part of its 2007 Rate Design Application ("RDA"). The new proposed test is a simplified test that establishes a maximum BC Hydro contribution towards the cost of a system extension of \$1,900 per residential customer and \$425/kW of demand for General Service customers. These allowances were developed using information from the Fully Allocated Cost of Service ("FACOS") study in the 2007 RDA. For example, the \$1,900 was based on a twenty-year present value of allocated residential Distribution demand-related costs (per customer).

3.3 Marketplace Review

Market conditions that drive consumer fuel choice have significantly changed since the current customer connection and system extension policies of the Terasen Utilities were put in place. Some of these changes include:

- **Commodity Pricing** – In recent years, the price differential between gas and electricity has narrowed. This change in costs has eroded much of the traditional operating cost advantage of natural gas. The nature of market-based pricing of natural gas relative to the Heritage-related electricity rates has created a misconception among many consumers and builders that natural gas space and water heating systems are now more expensive to operate than their electric equivalent.

- Technological change – There are a number of technological changes that have taken place in the past few years that directly affect the market share of natural gas. For example, a requirement that new buildings use high efficiency furnaces will cost customers more than mid efficient appliances. Further, due to the venting requirements of high efficiency furnaces, a high efficient water heater is also required thus further increasing costs. While the Company supports the use of high efficient appliances, this additional cost is creating additional barriers to connect to natural gas. The Company therefore needs to ensure that customers do not pay higher connection fees as a result of pursuing energy efficiency measures.
- Housing Market - Developers continue to be the decision makers for energy choice and their decisions are often driven by profit for the developer rather than the long term operating costs and benefits for the ultimate customer. Due to the robust housing market, rapid price increases in new housing stock and the reduced price advantage of natural gas, potential buyers are not making the energy choice a priority in their buying decision. They simply want to purchase an affordable property. As such it is in the best economic interest of a developer to install electricity for space and water heating rather than gas, as the developer cannot normally charge more for a new home with gas heating.
- The market shift to multi-family dwellings is also further cause for concern with respect to increasing electricity demand. Multi-family and condominium apartments are increasingly built with electric baseboard heating systems, again due to the low relative up-front capital cost, compounded by the relatively small operating cost impact due to the smaller floor spaces. Many developments employ electric baseboard heating and often electric fireplaces. It is the belief of the Company that in order for BC Hydro to achieve its conservation and electricity self sufficiency goals of the Energy Plan it should not be attaching space or water heating load.

The cumulative effect of these changes in the market place is that customers and developers are making sub-optimal decisions both from a cost and a societal perspective (as presented through the BC Government's Energy Plan). It is the belief of the Companies that in order to send the appropriate price signals, mitigate these impacts and ensure that the right decisions are made, a reduction in the upfront connection costs is appropriate and should be made at this time.

The Company commissioned Willis Energy to review and analyze the competitive position in British Columbia of natural gas relative to other energy forms. The report (attached as Appendix 2) describes the competitive pricing pressures that natural gas faces compared to electricity. The report also provides suggestions for potential growth areas and how incentives can help provide the appropriate market signals for customers to make optimal energy decisions.

4 Customer Connection Fees and Charges

4.1 Current Charges

The current customer connection fees and charges have been in place since January 1, 1997 following the review TGI's (then BC Gas Utility Ltd.) application for approval of the Service Line Cost Allowance Proposal. In the Decision dated October 7, 1996 issued concurrently with Order G-104-96, the Commission approved TGI's submission to set a Service Line Cost Allowance at \$1,100 and also directed TGI to implement a flat charge of \$300 inclusive of the existing \$85 administrative charge for all new services to residential and commercial customers. In accordance with the Decision, TGI subsequently filed amendments to its Gas Tariff to establish:

- A customer application fee of \$85;
- A Service Line Installation Fee (SLIF) of \$215 representing the minimum customer contribution per service line, and
- A Service Line Cost Allowance ("SLCA") of \$1,100 representing the cap on service line costs over which the customer must make a contribution.

In TGI's October 1996 submission, the proposed SLCA of \$1,100 was intended to represent the maximum capital expenditure that TGI would invest to install a service line to connect a new customer to the gas distribution system. The principal objective of the SLCA was to limit the costs the utility would otherwise incur for new customers with extraordinary connection costs. All new customers requesting service must pay the SLIF and any service

line costs in excess of the SLCA. In effect, therefore, TGI's maximum investment in service line installation costs is limited to \$1,100 less \$215 = \$885 per new customer service.

TGVI adopted TGI's customer connection policies beginning January 1, 2006 following Commission Order G-126-05. That Order approved the negotiated settlement reached by TGVI regarding its June 2005 Application for Approval of Forecast Rates and Revenue Requirements for Years 2006 and 2007. Since that time TGVI has used the same MX test methodology as is used for TGI, based on TGVI inputs, and also adopted the SLCA of \$1,100, the SLIF of \$215 and the new customer charge of \$85.

4.2 New Customer Application Fee

The Application Fee for new customers is intended to recover the administration costs associated with initiating service to a new customer and does not cover any of the capital costs. The current \$85 application fee has been in place since prior to 1996. Since that time, the processes have been streamlined and costs to enroll customers into the system have remained relatively stable or have declined. At this time no changes to this fee is proposed.

4.3 Service Line Cost Allowance

4.3.1 Review of October 1996 Application

The current SLCA was determined in 1996 by applying an MX test as a proxy for new residential customer connections to determine a target service line cost. Actual service line cost information was then reviewed to determine the maximum amount or cut-off point that would result in the average service line cost equal to the target cost. As described in Section 5 of this Application, the MX test is a 20 year discounted cash flow analysis that is used to determine a Profitability Index ("PI") which compares the present value of the revenues and fees paid by customers served by the system extension (excluding the cost of gas which flows through to all customers at the marginal cost of the gas supply) to the present value of the estimated costs to TGI to build and operate the extension and service

lines. The breakeven point (i.e. where the net present value equals zero) is represented by a PI equal to 1.0.

The 1996 results are summarized in Table 4.1. The cost of a main used in the test was based on TGI's then average cost of \$516 per new customer service. A target service line cost that would support a PI of 1.0 was then determined to be \$475 based on average consumption of 130 GJ per annum. The costs of all new service line connections completed in the period from January to September in 1996 resulted in an actual average cost of \$659 (Appendix 3, Schedule 1). The 1996 service line costs were then evaluated further to determine the maximum allowance that would result in reducing the average service line cost equal to the target cost of \$475. The resulting maximum allowance was determined to be \$1,100. These parameters are summarized as follows:

Table 4.1

<u>1996 Data</u>	<u>Per Customer Service</u>
Average Consumption	123 GJ per annum
Average Main Cost	\$516
Target Service Line Cost	\$475
Average Service Line Cost	\$659
Maximum Allowance	\$1,100

Based on the cost data related to 1996 service line installations, the proposed allowance of \$1,100 would have required 13% of new customers to pay contributions. The Company submitted at that time that this allowance presented a fair balance toward offsetting high service line costs and reducing the operating and administrative costs such as those required for preparing individual cost estimates and processing of contributions.

By Order No. G-104-96, the Commission accepted the methodology used by TGI and approved TGI's application to set a SLCA at a maximum of \$1,100 effective January 1, 1997. In addition, however, the Commission also determined that all customers would be required to make a minimum connection fee of \$300, inclusive of the \$85 application fee, regardless of the actual installation costs. The Company subsequently retained the \$85 application fee and established the Service Line Installation Fee ("SLIF") of \$215 as the minimum contribution by customers toward the cost of service line connection.

The SLCA and SLIF are currently applied both to new customer services that are connecting to an existing main and those connecting to a new main extension. Since the determination of the SLCA was calculated using the MX test on a proxy customer and included an average cost for a main, the following observations can also be made:

- TGI had proposed that the SLCA value be set at \$1,100 in 1996 without consideration of a minimum contribution of \$215. The net effect of the SLCA and the SLIF is that TGI's maximum investment toward service line installation costs is limited to \$1,100 less \$215 = \$885 per new customer installation. The intent of the SLCA calculation was to determine the maximum investment that the Company could make without unduly impacting existing customers. Therefore, if a minimum contribution is required, the SLCA should be increased. For example, if the maximum investment is determined to be \$1,100 and a minimum customer contribution of \$215 is required then the SLCA could be increased to \$1,315.
- The MX test used to determine the SLCA included the average cost of a main on a per customer service basis. In the case of customer connecting to existing main, by determining the maximum allowance based on setting the PI to one, this customer is implicitly also contributing to the cost of the existing main in addition to the direct contribution represented by the SLIF of \$215.
- In the case of the new main extensions, the MX test already incorporates the expected cost of the new main extension facilities as well as the service line costs in order to determine whether a customer contribution is required. Therefore, applying the SLCA in new main extensions could result in a requirement for a contribution even if the overall MX test results in a profitability index significantly greater than one.

4.4 Analysis of 2006 Data

Terasen Gas Inc.

The companies have reviewed TGI's 2006 actual cost data to determine the maximum allowance, or SLCA, based on the same methodology used in the 1996 application. This was done again by applying the current MX test to a single proxy customer based on current inputs and 2006 normalized annual consumption of a residential customer of 96.9 GJs.

As provided in Schedule 2 of Appendix 3, in 2006 TGI's average direct cost of new main installation per customer service was \$620. When input into the current MX test, this resulted in a target service line cost of \$1,170 to provide a PI of 1.0. Schedule 3 in Appendix 3 provides a summary of all 2006 service line costs for Rate 1 and Rate 2 Customers and shows that the average cost per service line prior to the consideration of any contributions was \$1,161. Since the average cost is less than the target rate of \$1,170, none of the 2006 service lines would have to be excluded to bring the average cost down to the target level. The maximum allowance based on this set of data would therefore be in excess of \$3,500.

As in the 1996 test, this calculation of the maximum allowance was based on average normalized consumption across TGI's residential customer base. Since 1996, however, TGI has experienced a decline in average annual use rate which is expected to continue as customers upgrade to higher efficiency appliances and also as a result of a higher proportion of multi family homes associated with new customer connections. In order to address the decline in annual use rates, sensitivity scenarios were also run assuming annual consumption of 90 and 80 GJs. As shown below, these sensitivities resulted in a maximum allowance of \$2,925 and \$1,535 respectively.

Table 4.2 TGI Customer Service Line Maximum Cost Allowance

Average Annual Consumption GJ	96.9	90	80
Average Main Cost	\$ 620	\$620	\$620
Target Service Line Cost	\$1,181	\$1,064	\$ 910
Average Service Line Cost	\$1,161	\$1,161	\$1,161
Maximum Allowance	>\$3500	\$2,925	\$1,535
% of Customers > Maximum	0%	8%	19%

Terasen Gas (Vancouver Island) Inc.

The 2006 TGVI data was also evaluated to determine the maximum allowance by applying the same methodology based on TGVI's inputs and average costs. The MX test was applied to a proxy customer based on 2006 average cost of new main per customer service of \$1,086 (Schedule 2 Appendix 3) and the 2006 normalized average consumption for a residential customer of 60.2 GJs. The target service line cost was determined to be \$1,072 which when compared to the 2006 service line costs summarized in Schedule 4 in Appendix 3 resulted in a maximum allowance of \$1,473 per customer.

In TGVI's case however, the utility is experiencing increasing average annual use per customer as new customers generally have higher consumption than the average of the existing customer base. Two sensitivity scenarios were therefore evaluated. The first scenario was based on the assumption that the consumption of new customers is 10% greater than the current average across the customer base. In the second case, the objective was to determine the consumption level that would support a maximum allowance of \$1,535 to match the allowance determined in the case of TGI in the sensitivity scenario where new customer consumption averages 80 GJs per annum.

Table 4.3: TGVI: 2006 Customer Service Lines

Average Annual Consumption GJ	60.2	66	61
Average Main Cost	\$1,086	\$1,086	\$1,086
Target Service Line Cost	\$1,072	\$1,250	\$1,093
Average Service Line Cost	\$1,573	\$1,573	\$1,573
Maximum Allowance	\$1,473	\$2,133	\$1,535
% of Customers > Maximum	35%	21%	36%

4.4.1 Observations and Conclusions

The maximum allowance provided in Tables 4.2 and 4.3 represents the maximum investment that TGI or TGVI can make toward the cost of the service line and maintain an average PI of 1.0. If customers are required to make a minimum contribution regardless of the cost of the connection, such as the SLIF, then the maximum allowance should be increased in order to maintain the level TGI or TGVI can invest in the customer service line.

As shown by the results in Tables 4.2 and 4.3, the calculation of the maximum allowance is sensitive to the factors used in the proxy MX test. TGI and TGVI will be reviewing these factors on a regular basis to determine if adjustments need to be made to ensure new customers are not paying more to connect to the system than necessary while not unduly impacting existing customers.

The SLCA currently applies to both residential and small commercial customers. However the MX test methodology used to determine the target service line costs was based costs and revenues associated with a residential customer only. As the small commercial customer generally has higher consumption levels, if the same methodology was applied it could result in a higher service line allowance for these customers. However, the commercial customers represent only a small percentage of total customer additions in each year, therefore the impact of a “weighted” SLCA may be relatively small.

The methodology used to determine the maximum allowance, also assumes that the customer is contributing to the cost of mains through its rates. In the case of new customers connecting to an existing main, the net result is that these customers, on average, offset the full cost of new service line connections and also provide a benefit to existing customers by contributing to the cost of existing mains. In effect the PI is greater than 1.0.

The application of a maximum allowance that takes into account the average cost of mains may be appropriate in the case of a new customer connecting to an existing main. However, in the case of a new main extension test, the expected costs of both the new main and the service line costs are included in the calculation to determine the requirement for a capital contribution. The impact of the SLCA in a main extension is further discussed in Section 5.

Although TGVl and TGI currently have different rate structures and consumption patterns, applying the same SLCA across both service areas would have the benefit of being easier to administer and to explain to customers and developers. From the customer's perspective, it would also provide similar price signals and provide equal opportunity to new customers regardless of location. The results shown in Tables 4.2 and 4.3 for TGI and TGVl respectively demonstrates that a maximum allowance of \$1,535 dollars would recognize the costs differences and changes in consumption patterns being experienced at each utility.

The appropriate application of the SLCA will reduce the administrative costs associated with determining new customer connections. For example, as shown in Tables 4.2 and 4.3, if the SLCA was set at \$1,535, the percentage of new connections that would be in excess of that amount is 19% for TGI and 36% for TGVl.

The SLCA is based on establishing the maximum service line allowance such that new natural gas customers are not expected to impact existing natural gas customers from a cost perspective. It does not, however, recognize the societal benefits that could be obtained by promoting the use of natural gas over the use of electricity for space water heating loads. In addition, the methodology used to develop the SLCA does not recognize the benefits of adopting energy efficient appliances and other measures that improve the use of energy. Perversely, all else being equal, decreasing annual use per customer due to the adoption of energy efficiency measures would decrease the maximum allowance and require customers to make higher contributions. In order to encourage the right behavior, the application of the SLCA should allow adjustments to be made in order to ensure the appropriate price signals are in place to support fuel choice and efficiency measures from a new customer perspective. This is further discussed in Section 6 of this application.

4.5 Connection Fees and Charges Recommendations

In general it is recommended that customer charges and fees should be updated to reflect current costs and conditions. In addition, consideration should be given to providing further incentives to ensure that customers are not penalized or discouraged by the adoption of energy efficiency measures. More specifically, the Companies propose the following changes:

2. For new customer connections to existing mains it is recommended that:

- The minimum contribution (SLIF) of \$215 be eliminated;
- The SLCA be based on a maximum investment from the utility of \$1,535 for both TGI and TGVI. For example, if it is determined that the SLIF is eliminated the SLCA would be equal to \$1,535. On the other hand if it is determined that the SLIF should remain at \$215, the proposed SLCA is \$1,750;
- Additional allowances should be made to the SLCA to recognize the benefits of energy efficiency measures.

3. For TGI and TGVI customers connecting to new main extensions it is recommended that:

- Both the SLIF and the SLCA be eliminated. All service line and main costs are captured in the MX test used for new extensions in order to determine a customer contribution and therefore elimination of the SLCA and the SLIF will not change the requirement for customer contribution where the profitability index does not meet the required hurdle rate.

5 Main Extension Test

Both TGI and TGVI currently use the same discounted cash flow test to evaluate main extensions, however the inputs for the tests vary between each utility. The TGI test was first approved by Commission Order No. G-104-96. TGVI adopted TGI's customer connection policies beginning January 1, 2006 following Commission Order No. G-126-05.

The TGI/TGVI MX test is a twenty year discounted cash flow ("DCF") analysis which compares the present value ("PV") of cash inflows to the PV of the cash outflows from a proposed system extension. The cash inflows of the MX test are the revenues from rates and fees paid by customers served by the main extension. The revenues used in the test are delivery margin revenues and do not include the commodity cost or midstream charge. The cash outflows are the estimated costs for TGI/TGVI to build and operate the system including capital costs for materials and installation of the main, service line and meter, on-going operating and maintenance costs and upstream system improvement costs.

The MX test is used to determine a Profitability Index (“PI”) that represents a ratio of the PV of expected revenues to the PV of expected costs. A PI of 1.0 or greater means that the expected PV of the inflows equals or exceeds the PV of the outflows (i.e.: the Net Present Value (NPV) equals or is greater than zero) and the system extension can proceed without the need for a customer contribution. If the PI is less than 1.0, a contribution in aid of construction may be required to make up the shortfall in order that the system extension can be built without negative economic impact to existing customers.

5.1 *MX Test Analysis Results*

5.1.1 2007 MX Test Forecast Outcomes

Under the current policy, each individual main extension must have a PI of 1.0 or greater before it can proceed. In aggregate, therefore, it is expected that the PI would be significantly greater than 1.0. If a goal of an MX test is to not negatively impact existing customers, then the current policy goes one step further by ensuring that in aggregate new customers pay more than the costs to connect them to the system. To validate this hypothesis, the Companies analyzed main extensions undertaken in 2007. The results are provided in Schedule 5 of Appendix 3 and are summarized below.

For the analysis the Terasen Utilities reviewed all the main extensions that were started between January 1, 2007 and April 2007 for TGI and TGVI. After removing any tests that did not have complete data, 112 TGI tests and 55 TGVI tests were reviewed. For the purpose of the review, forecast costs, consumption and attachments were used. The MX test results for this sample resulted in PIs that ranged from 0.05 to 30.16 for the individual MX tests prior to consideration of any contribution in aid of construction.

The aggregate PI for all the completed tests was then determined for the sample period. The aggregate PI was defined as the total revenue for all the main extensions compared to the total costs for all main extensions in the period based on forecast values. Using this population of data, the aggregate PI for TGI was 2.3 and the aggregate PI for TGVI was 1.83. The aggregate of both TGI and TGVI was 2.14. However, if all negative PI's were adjusted to equal a PI of 1 to account for contributions from customers, the aggregate PI

would have been marginally higher than 2.14. If the Companies were to take an approach similar to Enbridge, individual main extensions could have a PI of less than 1.0, and on an aggregate basis, the PI would be more than 1.0 but would likely be less than 2.14.

5.2 Main Extension Test Input Parameters

The current 20 year discounted cash flow main extension test for both TGI and TGVI includes the following parameters:

Table 5.1

Revenue	
<i>Consumption Estimates</i>	From Residential End User Study
<i>Revenue (based upon Consumption)</i>	Specific to each utility and Rate Class. Revenues are for distribution margin only and do not include the cost of commodity.
<i>Application Fee</i>	\$85
Capital Costs	
<i>Installation Costs</i>	Direct Capital Cost for the Main Extension, Service Line and Meters/Regulators. Based upon geographical costing model.
<i>Overhead Rate</i>	Incremental indirect capital costs – currently 32%.
<i>Service Line Installation Fee (contribution in aid of construction)</i>	(\$215)
Incremental Operating Costs and Expenses	
<i>Operation & Maintenance</i>	Yearly incremental O&M by Rate class
<i>Property Tax - 1% in Lieu of General Municipal Taxes</i>	1% of gross revenues (including commodity costs)
<i>Property Tax – General, School and Other</i>	2% of assessed value of mains and services
<i>System Improvements</i>	Currently \$0.35/GJ for TGI (Rates 1 and 2), \$0.50/GJ for TGVI
<i>Income Taxes</i>	Combined federal and provincial corporate income tax rate (including surcharges and/or capital taxes, if applicable.) Capital Cost Allowance – as per applicable CCA rates
Other Factors	
<i>Discount Rate</i>	Incremental weighted average cost of capital (real, after-tax)

With the exception of System Improvement (“SI”) charges, which are discussed below, the input factors listed above are reviewed and updated on a regular basis. In most cases the factors are reviewed annually and updated as appropriate. Updates to some factors, such

as income tax rates and property taxes are dependent on changes being implemented by levels of government and occur more sporadically.

5.2.1 SI Charge

The TGI SI charge methodology was developed in 1994 and was intended to allocate the costs for system improvements on the distribution system that result from increases in capacity from the addition of new customers. The analysis reviews the forecast of system improvements and growth in peak day for a five year forecast period which is then converted to a per GJ amount. The SI charge has been increased by inflation from its original calculation and is currently \$0.35/GJ. TGVI has traditionally used a transmission SI based methodology. Prior to 2006, the TGVI SI charge as part of the then current 15 year discounted revenue requirement MX test was \$0.50/GJ. As part of the TGVI Negotiated Settlement as approved by Commission Order No. 161-06 and Reasons for Decision, the Commission determined that the SI charge should remain at \$0.50/GJ.

A SI analysis for both TGVI and TGI was re-run using distribution five year growth and peak day forecasts for each utility consistent with the original TGI methodology. The resulting distribution SI for TGI is \$0.16/GJ, and \$0.151/GJ for TGVI. The Companies believe that a consistent approach across both TGI and TGVI would be preferential as it would remove unnecessary complexity from the MX test. A distribution derived SI charge is consistent with this philosophy.

Other than the specific changes sought in respect to System Improvements in this application, the Companies intend to continue the same process of regular review and updating of the main extension test factors.

5.3 SLCA and SLIF Impact

Section 4 of this Application discusses the development and the application of the SLCA and the SLIF as they apply to the MX test. Currently these factors are applied to both infill customers and customers connecting to new main extensions. As the total expected costs of the new main and service lines are included in the main extension test, the Companies propose that the SLCA and the SLIF both be removed from the MX test.

Under the current policies, an evaluation of a new main extension could result in four outcomes as illustrated in Table 5.2.

Table 5.2 Main Extension Scenarios

MX Test	Service Line Costs	Customer Contribution
MX Test Result <1.0	Service Line Costs > SLCA	SLIF + Main contribution + Service line costs > SLCA
	Service Line Costs < SLCA	SLIF + Main Contribution
MX Test Result > 1.0	Service Line Costs > SLCA	SLIF + Service line costs > SLCA
	Service Line Costs < SLCA	SLIF

The requirement of a SLIF does not impact the total contribution required for main extensions that do not meet the minimum hurdle or profitability index. The MX test considers the SLIF as a contribution in aid of construction (“CIAOC”) that offsets the total costs of the main extension and service lines in the determination of the requirement of a capital contribution. In the case of a contributory extension, if the SLIF is eliminated, the amount of contribution determined by the MX test would increase by the same amount, and therefore the total customer contribution would be the same in either scenario.

However, the SLIF is an incremental cost to customers to connect to the natural gas system where the MX test would not otherwise require a capital contribution. Elimination of the SLIF would reduce the cost to these customers and still produce positive benefits for existing customers. Elimination of this cost sends the right price signal to these customers.

Similarly, the elimination of the SLCA will not change the requirement for customers to make a capital contribution in order to meet the minimum hurdle or profitability index in the MX test. However, removal of the SLCA will allow customers where main extension facilities are relatively low cost to offset any savings against high service line costs before being required to make a capital contribution.

An example of a system extension where the MX test was positive but where the customer was still required to make a capital contribution is illustrated in Figure 5.1. In this case, the MX test provided a significantly positive result with a PI of 2.39. If the SLIF and the SLCA was eliminated, the customer's costs would have been limited to the administration fee, however the PI would have only decreased to 2.26 and therefore the customer would have continued to be economic.

Figure 5.1

TGI Project # 4110012917

- Rate Schedule 2 customer
- Market segment – Small Apartment
- MX Test PI = 2.39
- Service line cost = \$1,563.00

- Cost to Customer
 - New Customer Administration Fee - \$85.00
 - MX Test - \$0.00
 - Service Line
 - \$1,563.00 minus \$1100.00 (SLCA) = \$463.00
 - SLIF - \$215.00
 - Total Cost to customer - **\$763.00**

5.4 Observations and Conclusions

Under the current test, each individual main extension must have a PI of 1.0 or above to be considered economic. Those that have a PI of less than one must pay a contribution sufficient such that the PI = 1. As discussed above, the PI of all extensions when considered in aggregate is much higher than 1.0. By requiring every MX test to have a PI equal to or above 1, on average new customers are paying more than their fair share of costs. If the Companies were to aggregate main extensions on an annual basis such that the aggregate PI was above 1, a better balance of interests between new and existing customers would occur.

The aggregated or system-wide approach for the target PI is consistent with BC Hydro's proposed system extension test in its 2007 Rate Design Application and directly parallel to

the practice of gas utilities in Ontario (see Enbridge Gas discussion in Appendix 1). BC Hydro has proposed a maximum allowance of \$1,900 per residential customer that it will contribute towards the capital cost of a system extension. The \$1,900 allowance is to be applied on system-wide basis without reference to specific incremental costs and revenues of that extension. It is reasonable to expect that customers on some extensions will benefit from this aggregated approach while customers on other extensions will not. The Ontario gas utilities employ a threshold PI of 0.8 for individual main extensions and must maintain a system-wide PI of 1.0.

Changing the threshold PI to less than 1.0 but on aggregate higher than 1.0 will simplify the process and send the appropriate signal to customers. In addition, the elimination of the SLIF and the removal of the SLCA will not harm existing customers; rather the changes will ensure that new customers are not simply paying a contribution when the net of the main extension costs and the service line costs result in the customer addition meeting the individual PI threshold.

5.5 *MX Test Recommendations*

The Terasen Utilities propose to continue using the 20 year DCF MX test, using the same methodology as the current TGI and TGVI test. The Companies propose to evaluate of MX tests on an aggregated basis as well as on an individual basis. The Companies believe that this is consistent with cost-causation principles and will not cause current customers to be harmed.

To send appropriate market signals to customers attaching to the system, and ensure that there is a better balance of interests between new and existing customers, the Company proposes to change the threshold for passing the MX test from a PI of 1.0 to a PI of 0.80 for individual main extensions. For example, if a MX test had a PI of 0.6, the customer would have to pay a contribution to reach the PI threshold of 0.80.

On a system wide basis the Companies proposes that each utility will have an aggregate annual main extension PI of 1.1. A random sampling of tests would be reviewed each year to determine if the aggregate PI is higher or lower than this level. If the annual aggregate PI was above or below 1.1, the individual threshold PI would be adjusted, on a go forward basis, in order to achieve the aggregate PI of 1.1. The aggregated PI of 1.1 proposed in this

Application is conceptually the same as the practice in Ontario, however it provides a 10% cushion to allow for unanticipated variations that may occur before the threshold PI for individual main extensions is adjusted. This approach is similar to that used by the major Ontario gas utilities as illustrated by the description of Enbridge's policies in Appendix 1.

The Companies propose to use the same distribution methodology for calculating the SI charge for both TGVI and TGI. TGVI would therefore use a distribution related SI charge calculated in the same manner as TGI.

The Companies propose to change the process for determining service line costs as part of a main extension test. When a new main extension is required, capital costs required to provide service to the customer will be input into the MX test and a distinction between service line and main will not be made therefore eliminating the requirement for the SLCA in these cases. The Companies also propose to eliminate the SLIF for all customers requiring a main extension as noted previously.

6 Energy Usage and Efficiency Allowance

The Companies believe that they should be encouraging efficiency on the system, encouraging conservation of energy and helping consumers of energy meet the societal goals outlined by the Energy Plan. The Companies believe that it is possible through the system extension and connection policies to influence customers' choice of energy and help meet the goals of the Energy Plan. However, at present, neither the SLCA nor the MX test make a distinction between high efficiency appliances and standard efficiency appliances. In both the MX test and the SLCA, consumption of gas is used to arrive at either revenues for the MX test or as an input to affect the SLCA. Currently, neither the MX test nor the SLCA use different volume inputs to account for the use of high efficient appliances. Perversely, if volumes were adjusted to reflect the use of high efficiency appliances instead of an average value, the MX test would result in a less profitable extension, and/or the SLCA would be lower. The Companies believe that changes to incorporate an allowance for high efficiency and conservation within both the MX test and the SLCA will result in appropriate market signals and encouragement of conservation of energy.

The Company proposes to give additional credit for using space and water heating appliances and for making energy efficient choices within the SLCA and MX test as per the following:

- Space and Water Heating – Customers who have both gas fired space and water heating as part of their appliance portfolio, will receive a credit of 5% of the volume otherwise used for said appliance. For example, if a furnace and water heater on aggregate use 80GJ/year, the Company would use the value of 84 GJ/year for consumption in the MX test.

The Companies believe that this small change will help send the appropriate signal to the market place of the right fuel at the right time and the right place. Further the Companies believe that this change will result in avoided future electricity requirements therefore helping to meet the Energy Plan goals.

- High Efficiency – Customers who have both high efficiency gas fired space and water heating would receive a credit of 10% of the volume otherwise used for both appliances. For example, if a furnace and water heater on aggregate use 80 GJ/year, the Company would use the value of 88 GJ/year for consumption in the MX test⁸.

Increasing the volume amount for high efficient appliances, within the MX test, increases the likelihood that the MX test will be positive. Increasing volume used to derive the SLCA will result in a higher SLCA. Using larger consumption values for high efficient appliances should therefore send more appropriate market signals to customers wanting to use natural gas for space and water heating and help provide a context to educate consumers on the importance of high efficiency appliance use, and again is therefore consistent with the Energy Plan.

⁸ For space heating, the Companies consider an Energy Star rated furnace or boiler as being high efficiency. For water heating, the Companies consider tankless water heaters or water heaters with an efficiency rating of 78% or greater as being high efficiency.

- Leadership in Energy and Environmental Design (“LEED™”) Building Efficiency – Customers who have both high efficiency gas fired space and water heating appliances and who attain a minimum of LEED™ General Certification will receive a credit of 15% of the volume otherwise used for both appliances. For example, if a furnace and water heater on aggregate use 80GJ./year, the Company would use the value of 92 GJ/year for consumption in the MX test.

Meeting LEED™ building requirements adds to the capital cost to construct a building. Increasing the volume amount for space and water heated appliances in LEED™ buildings, within the MX test, increases the likelihood that the MX test will be positive. Increasing the volume used to derive the SLCA will result in a higher SLCA. While the costs incurred to meet LEED™ building design are unlikely to be offset by a lower connection fee, the Companies believe it is important to send the appropriate market signals with respect to conservation and efficiency. Using slightly larger consumption values for high efficient appliances and LEED™ building design therefore sends appropriate market signals to customers wanting to use natural gas for space and water heating and is therefore consistent with the Energy Plan.

The following table outlines the proposed consumption methodology within the MX test:

Table 6.1

Appliance	TGI/VI Consumption
Pool	As per Residential End User Study
Hot tub	
Range	
Fireplace Heating	
Fireplace non-heating	
Dryer	
BBQ	
Patio Heater	
Furnace/Boiler	
Water Heater	
Furnace and Water Heating	105% X Furnace and Water Heater Value
High Efficient Space and Water Heating	110% X Furnace and Water Heater Value
High Efficient Furnace and Water Heating and LEED Building	115% X Furnace and Water Heater Value

The Companies also propose to recognize the above goals in the application of the SLCA. As the SLCA is intended to simplify the process and application of connection charges, the Company proposes to use consumption allowance credits based upon the current average residential consumption values in the MX test for space and water heating of 60GJ/year for forced air space heating and 20GJ/year for water heating. Using these values, and applying the percentage credit as noted in Table 6.1 an increase in GJ's for determining the maximum allowance used to derive the SLCA, as described in section 4 can be determined. This is summarized in the following table:

Table 6.2

<u>Energy Efficiency Credits</u>	<u>GJ Incentive</u>	<u>Increase in SLCA*</u>
Space and Water Heating	4 GJ	\$65
High Efficient Space and Water Heating	8 GJ	\$130
LEED Building and High Efficient Space and Water Heating	12 GJ	\$195

The Companies believe that these changes will be positive for both new and current customers. Current customers will benefit because the system and extension tests and policies will not discourage attachment to the system for customers who consider conservation and efficiency. New customers benefit because they will not be penalized due to the selection of gas for heating or for more efficient appliance and building design. It should be noted that existing customers who upgrade to more efficient appliances or upgrade their buildings reduce their annual consumption and arguably impose a cost on all customers, however in the interests of both energy efficiency and environmental performance this type of behavior is encouraged. The Companies believe that the changes are beneficial to all energy consumers in the province and help to achieve the goals of the Energy Plan.

7 Summary and Approvals

The Companies believe that the changes proposed in this Application will help send the appropriate market signals to developers and customers and offset some of the barriers deterring customers from connecting to natural gas. The changes will also simplify the current test and process and make them easier for customers to understand. The Companies also believe that the changes proposed will help BC meet targets as set out in the Energy Plan.

The Companies respectfully seek approval for the following changes to their system and connection policies:

- With respect to Connection Fees and Charges for Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.:
 - To eliminate the Service Line Installation Fee of \$215.
 - To implement a Service Line Cost Allowance of \$1,535.
 - To cease using the Service Line Cost Allowance for new main extension applications.
 - To increase the Service Line Cost Allowance to recognize the benefits of energy efficiency.
- With respect to the Main Extension Tests for Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.:
 - To continue using the discounted cash flow main extension test.
 - To use distribution related costs to determine the System Improvement Charge for Terasen Gas (Vancouver Island) Inc.
 - To use a Profitability Index of 0.80 as the lower economic threshold for passing individual main extensions.
 - To use an aggregate Profitability Index of 1.10 as the threshold for all main extensions completed on an annual basis.
 - To eliminate the Service Line Installation Fee and the Service Line Cost Allowance for new main extensions.
- With respect to the proposed Energy Usage and Efficiency Allowance for Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.:
 - To approve the proposed allowances in the Main Extension Test and the Service Line Cost Allowance to encourage gas fired space and water heating, high efficient space and water heating, and high efficient space and water heating in Leadership in Energy and Environmental Design (“LEED™”) Building.

Appendix 1

Atco Gas*Main Extension Policy*

The Atco Gas main extension policy is based largely on a principle of non-discriminatory access to service, rather than on any overriding concern for the potential subsidization of new customers by existing customers. *Atco Gas' Terms and Conditions for Distribution Service Connections* states that if an applicant's premise is within a municipality with a franchise agreement with Atco, then Atco will extend the pipeline system at no charge. This is based on the condition that the municipality must have extended or will extend the water and sewer services to the applicant as well.

If the customer is not within a municipality, and the main extension (excluding the service line) does not exceed 50 metres in length, and an easement is provided, then Atco Gas will provide the extension at no charge.

If the extension is greater than 50 metres, the applicant must pay the difference between the total estimated costs, and the total revenue that Atco Gas expects to receive from the customer for the first three years.

Service Line Extension Policy

As per the *Terms and Conditions for Distribution Service Connections Schedule C Non Discretionary Charges*, there is a \$100 Basic Charge to apply for service connection, and specific pipe installation charges based on service line diameter and season.

Avista Utilities - Washington*Gas Extension Policy*

Schedule 151A of Avista Utilities – Washington ("Avista Washington") tariff Naming Rates for Natural Gas Service and Containing Rules and Regulations Governing Service states

that for a residential customer, an extension is no cost if the annual revenue is not less than one-third of the extension cost, (which includes the cost of mains, service lines and pressure regulating equipment).

If the annual revenue is more than one-sixth, but less than one-third of the extension cost, an extension will still be supplied only if the applicant agrees to pay an annual amount for gas service for a period of five years that is not less than one-third the extension cost.

Avista Utilities - Oregon

Main Extension Policy

Avista Utilities – Oregon’s (“Avista Oregon”) *Tariff Schedules Applicable to the Gas Service of Avista Utilities Rule 15* states that if the estimated cost does not exceed three times the estimated annual gross revenue as determined by Avista, then the main extension is free. There is also a condition that the requested area must be of permanence to warrant the expenditure by Avista Oregon.

If the estimated cost does exceed three times the estimated annual gross revenue, then the applicant may choose to advance in cash the difference between the total cost and three times the estimated annual gross revenue.

If upon completion, it is determined that the actual cost is less than the estimated cost, then the money is refunded without interest.

Service Line Extension Policy

Avista Oregon's *Tariff Schedules Applicable to the Gas Service of Avista Utilities Rule 16* states that the service line is free if the extension is less than 40 feet.

Any extension in excess of 40 feet requires an advance from the customer. If the applicant's building is located at a large distance from the main or is coming off of a high pressure main, then Avista may waive the additional charge.

Northwest Natural Gas Company ("NW Natural") – Washington and Oregon

Main Extension Policy

As per Northwest Natural's *Schedule E - Distribution of Facilities Extensions for Applicant-Requested Services and Mains*, an applicant for a main receives a construction allowance equal to five times the delivery margin for the applicable rate schedule, which is then multiplied by the annual estimated energy usage (five year net revenue test).

The construction allowance is equal to 5.0 times the delivery margin for the applicable rate schedule, times the annual estimated energy usage attributable to the applicants installation characteristics. The estimated energy usage is determined from structure characteristics, demographics, heating degree days, and type and number of appliances installed.

The estimated cost to construct the main extension offsets the applicant's construction allowance. If the allowance is greater than the cost of construction, then the main extension is free. If the cost to construct the main extension is greater than the allowance, the applicant must pay a construction contribution equal to the difference between the cost to construct and the construction allowance, plus the estimated tax effects on the construction contribution amount at 22.859%.

Northwest Natural, at their discretion, may perform a 30 DCF test. If the DCF is performed and it results in a reduction in the required construction contribution, the applicant has the choice of paying the reduced contribution and waiving the right to any future refunds, or paying a higher contribution, which would then be subject to a refund.

A representative from Northwest Natural confirmed that very few main and service line attachments do not pass and require customer contributions. Builders also have the

opportunity to provide a trench to the property to save costs, and thus ensure everyone passes the test.

The service line extension policy is the same as the main extension policy.

Enbridge Gas

Main Extension Policy

Enbridge's 2007 Test Year Rate Case *Economic Feasibility Procedure and Policy* handles system expansion on a project-by-project basis requiring an individual project profitability index of 0.80 or greater and the overall investment portfolio (the costs and revenues associated with all new distribution customers who are forecast to be attached to new and existing mains in the fiscal year) at a profitability index greater than 1.0 with a safety margin.

Each project has an impact on the rolling 12 month cumulative net present value profitability index, which must be maintained at a net present value of zero or greater, and a targeted profitability index ratio of 1.0 or greater. For negative net present values, a contribution in aid of construction must be provided to bring the net present value to a viable level.

For residential customers, "Budget Average Unit Costs" are used for pricing mains for subdivision customers unless more information is available to obtain field estimates.

Revenue is calculated based on a revenue horizon of 40 years from the in-service date of the initial mains.

Service Line Extension Policy

Enbridge Gas will install a service line free of charge up to 30 meters from the property line.

FortisBC Inc. (“FortisBC”)*Main Extension Policy*

As outlined FortisBC *Electric Tariff B.C.U.C. No. 1 For Service in the West Kootenay and Okanagan Areas Schedule 74 – Extensions*, FortisBC will contribute a transformer (which includes transformers, cutouts, lightning arrestors and associated equipment, and labour to install), drop service (which includes that portion of an overhead service connection extending not more than 30 meters onto the applicant's property and not requiring any intermediate support on the applicant's property), and metering equipment, toward new services operating at distribution voltage (35 kV or less). When the applicant requests an underground service, the FortisBC contribution will be limited to an amount for an equivalent overhead transformer, drop service, and metering equipment. The customer must then pay the Customer Portion of Costs "CPC" - Extension Cost plus the Operation and Maintenance Surcharge, (applicable for system extensions costing more than \$2,000 per customer).

Extension Cost – FortisBC estimates the cost of constructing an extension including the cost of labour, material and construction equipment. Extension costs include the cost of connecting the extension to the FortisBC distribution system, inspection costs, survey costs, permit costs and do not include the cost of the transformer, drop service and metering equipment. According to the tariff, applicants are charged an incremental operation and maintenance surcharge on a one-time basis for extensions costing more than \$2,000 per customer.

Special Contracts

An applicant may also be required to make a contribution in addition to the CPC where additional investment is made to provide service at a phase and voltage not presently available or for a large non-residential customer where new or upgraded substation and transmission facilities may be required.

Service Line Extension Policy

According to *Section 2.4 Connection of Service of the FortisBC Electric Tariff*, FortisBC will connect an overhead drop service to the customer's premises after receipt of an application; payment of connection and installation charges. For extensions requiring more than a drop service, connection will be made under the provisions of the applicable extension schedule.

Schedule 82 - Charges for Installation of New/Upgraded Services of the FortisBC electric tariff outlines that the connection charge for single phase is \$200, and there is an incremental charge of \$3.00 per ampere above 100 amperes for single phase.

BC Hydro

BC Hydro's current system extension test ("SET") was developed in response to the BCUC System Extension Guidelines and was implemented at the beginning of 1998. The BC Hydro SET uses an incremental analysis approach and employs discounted cash flow principles. BC Hydro's current SET model is thorough in the range of costs and revenues it considers in the economic analysis of system extensions. While the BC Hydro SET model potentially maintains similar economic rigor to the model used by TGI, in the administration of the SET certain key input factors have not been updated since the introduction of the model in 1998.

BC Hydro's proposed approach to system extensions in the 2007 Rate Design Application ("RDA") moves away from a detailed incremental approach using a discounted cash flow model. BC Hydro has proposed a model that employs simplified maximum contribution that it will make towards a system extension. The maximum system extension contribution will be \$1,900 per customer for residential customers and \$425/kW of peak demand for commercial and general service customers. These allowances were developed using information from the Fully Allocated Cost of Service ("FACOS") study in the 2007 RDA. For example, the \$1,900 was based on a twenty-year present value of allocated residential Distribution demand-related costs (per customer).

For the residential class the \$1,900 per customer allowance is independent of the annual customer loads. The same allowance of \$1,900 per customer will apply to larger volume residential accounts as to smaller volume accounts. Another aspect of the proposed system extension approach is that it does not give direct consideration to incremental upstream costs.

The chief benefit of BC Hydro's proposed system extension model is in its simplicity and ease of administration. The calculation of customer contributions will be very straightforward and easy to explain to developers and customers.

Appendix 2



Energy Market Competitive Assessment

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1 INTRODUCTION

The purpose of this Study is to identify and quantify the potential for increased natural gas sales and the competitive risks that could reduce natural gas sales. The study is divided into opportunities and threats. Opportunities are categorized as customer choices which would lead to an increase in natural gas sales and threats are categorized as customer choices which would lead to a decrease in natural gas sales.

It is important to note that a threat, defined as a risk of decreased natural gas sales may not necessarily be a business threat to Terasen Gas. In fact, it may be a business opportunity in that it may provide Terasen Gas with an opportunity to sell another type of service. Similarly, an opportunity defined as a potential for increased natural gas sales, may not be a good business opportunity due to the profile of the gas use connected with the sale.

For both the opportunities and threats, gas sale increases and decreases are estimated in annual volumes over a five-year time window. For example, an estimated impact of 1.0 PJ means that over a five-year period annual gas sales would be increased or decreased by 1.0 PJ.

In the retrofit case, a 1.0 PJ impact amount means the expected equipment retrofits that would occur over a five-year period which would result in a change in gas sales of 1.0 PJ annually. In the new construction case the impact amount is also an annual sales volume but it is based on the number of facilities that are expected to be built over the next five years. For example, if it is forecast that 1,000 buildings of a particular type will be built over the next five years and that the gas load in these buildings due to a particular opportunity is expected to be five percent higher than current forecast, then the increase in annual sales volume would be five percent multiplied by the estimated gas use in the 1,000 buildings multiplied by five.

The purpose of this study is to assist Terasen Gas to rank the competitive threats and opportunities to their markets. The values estimated are based on observed trends and not detailed market studies. The model developed in conducting this study, is available for analyzing different future market scenarios.

2 SUMMARY

There is a significant competitive threat to natural gas sales in British Columbia due to an electricity pricing and practices advantage. The prices that BC consumers pay for electricity is based mainly on the cost of “Heritage” power while the price of natural gas is mainly due to a value for gas based on a North American market derived value. “Heritage” power is the electricity generated by hydroelectric projects that were built 25 to 70 years ago. This discrepancy between the cost of “heritage” power and the current market price for energy was not a major factor until recently.

For approximately 15 years from 1985 to 2000, the price of electricity was relatively stable at six cents/kWh for residential customers and the price of natural gas was about four dollars per GJ. Electricity and natural gas as energy forms have relative advantages and disadvantages over each other; however, a key advantage to natural gas over this period was that natural gas was significantly less expensive. On a direct energy comparison four dollars per GJ is equal to 1.4 cents/kWh, therefore even though electric appliances, furnaces and boilers may be more efficient than their gas counterparts; for many energy applications such as space heating, natural gas dominated the market largely because of overall cost advantages.

Currently however, the price of electricity for residential customers has only gone up slightly to 6.2 cents/kWh, or \$17.43/GJ, but natural gas at the retail level is 4.5 cents/kWh or \$12.50/GJ. Taking efficiency

into consideration, and the differences in capital costs, natural gas is no longer the obvious low-cost alternative.

The fact that natural gas is an energy source that can address the energy capacity needs of the Lower Mainland and Vancouver Island is important with respect to provincial energy planning. The major part of British Columbia's energy requirements are in the Lower Mainland and the southern part of Vancouver Island. However, the major sources of energy are in the interior and the north part of the province. The British Columbia Transmission Corporation (BCTC) is presently studying alternatives to meeting the need for increased transmission capacity into the Lower Mainland. If natural gas' share of the Lower Mainland and Vancouver Island space and water heating market were increased, the requirement for electricity capacity into the Lower Mainland would be reduced.

2.1 Residential Opportunities and Threats

Opportunities were assessed in terms of what promotional programs and in some cases financial incentives could accomplish in terms of increasing natural gas sales. For example, one of the most significant threats is loss of water heater market share. Gas water heaters however, could also be an opportunity for increased sales if a promotional program was combined with a joint BC Hydro/Terasen Gas incentive. It is suggested that a BC Hydro incentive could be justified in terms of reducing the electric utility's need to meet capacity in Lower Mainland and Vancouver Island.

The table below provides an estimate of the increase in gas sales due to different identified residential opportunities.

Table 1 - Estimate of Increase in Residential Annual Sales Due to Opportunities (PJ/yr)

Opportunity	Lower Mainland (LM)	Interior	Vancouver Island (VI)	Opportunities Total
Gas Water Heaters-Tanks	0.6	0.5	0.9	2.0
MURB Space Heating	1.5	0.2	0.1	1.9
Gas Water Heaters-Instantaneous	0.3	0.3	0.6	1.2
Outdoor Uses	0.2	0.1	0.2	0.5
Market Share Increase In Clothes Dryers	0.2	0.1	0.1	0.3
Jacuzzi-Hot Tubs	0.2	0.1	< 0.1	0.3
Driveway-Parking Lot Heating	0.1	0.1	< 0.1	0.2
Gas Fired District Heating	0.1	< 0.1	< 0.1	0.1
Total	3.1	1.4	2.0	6.5

Natural gas has a number of advantages which provide opportunities for increasing gas sales. The water heating "Opportunities" are generally recognized as lifestyle advantages to natural gas. Due to the capacity of natural gas water heaters, customers have the benefit of hot water when they need it. The other Opportunities are seen as opportunities in that they represent a large energy load where marketing programs should be able to increase natural gas' market share.

The following table provides explanations of the Impact Opportunities. SFD represents Single Family Dwellings. Section 8.1 provides more detail.

Table 2 – Residential Opportunity Impact Explanation Summary

Opportunity	Retrofit Explanations	New Construction
Gas Water Heaters – Tank and Instantaneous	Increase gas share of domestic water heaters in SFDs in all regions by 5 percentage points	Increase gas market share in SFDs for all regions to 80%.
MURB Space Heating	No impact on existing housing stock	Increase space heating gas market share from approximately 5% to 50% for Low Rise, High Rise buildings in all regions.
Outdoor Uses	Increase existing gas outdoor use in SFD stock by 20%.for all regions	Increase expected gas use in new construction SFDs for all regions by a factor of 2.
Gas Clothes Dryers	Increase existing market share in SFD stock by 5 percentage points.	Obtain 20% of market share in SFDs for new construction in all regions.
Jacuzzi – Hot Tubs	An increase in units in existing housing stock by 2,000 in Lower Mainland, 1,000 in the interior and 500 on VI.	An increase in units in New Construction by 1,000 in the Lower Mainland, 500 in the interior and 300 on VI.
Driveway Parking Lot Heating	An increase in units in existing housing stock by 1,000 in Lower Mainland, 500 in the interior and 200 on VI.	An increase in units in New Construction by 1,000 in the Lower Mainland, 500 in the interior and 200 on VI.
District Heating	No impact on existing housing stock.	Increase by 10 percentage points the gas hydronic market share in new high-rise construction for all regions.

For the Opportunities, it is suggested that the sum of all of the Opportunities is in the order of seven percent. This means that promotional programs to address the opportunities could result in sales being seven percent. greater with respect to the residential sector than the value estimated in the TGI and TGVI Resource Plans for 2016.

It is suggested that the key market for Terasen Gas is the single family residential market. In this market segment, natural gas still holds a dominant position, Given a more level playing field in terms of price, natural gas should still be able to maintain its position. The Multi-Unit Residential Buildings (MURBs) are a much tougher competitive environment for gas and it is less clear as to the marketing strategy that would be successful in terms of significantly reducing the threats and increasing the opportunities.

As indicated previously, since the price advantage of natural gas has been significantly reduced, there are a number of threats to the residential gas market. The table below indicates the magnitude of these threats.

Table 3 – Estimate of Decrease in Residential Annual Sales Due to Threats (PJ/yr)

Threats	Lower Mainland	Interior	Vancouver Island	Threats Total
Increase in Market Share Air to Air Heat Pumps	4.3	1.2	1.0	6.5
Reduction in Market Share for Gas Water Heaters versus Electric Water Heaters	3.3	1.2	1.0	5.5
Improved Electric Space Heating Control	1.9	0.4	0.6	2.9
Geothermal	0.4	0.1	0.2	0.7
Wood Pellets	0.3	0.2	0.1	0.6
Reduction in Market Share for Gas Fireplaces versus Electric Fireplaces	0.2	< 0.1	< 0.1	0.3
Total	10.5	3.1	2.8	16.5

It is not strictly logical to combine all the Threats because some of them will overlap each other. However, it is suggested that the sum of all of the Threats is in the order of 17% of Terasen's residential gas market. This means that the Threats could result in Terasen sales being 17% less than the value estimated in the TGI and TGI Resource Plans for year 2016.

The table below provides explanations with respect to the threat impact values.

Table 4 – Residential Threat Impact Explanation Summary

Threat	Retrofit Explanations	New Construction
Air to Air Heat Pumps	Five percent of existing gas heating market (high-rise excluded) will be converted to heat pumps within 10-year period for all regions	Reduce natural gas space heating market share in new construction (high-rise excluded) by 10% in all regions.
Electric Water Heaters versus Gas Water Heaters	The existing gas market share in all regions will be reduced by 10% (example existing market share in SFDs in Lower Mainland is reduced from 83% to 73%)	Forecast market dominance of gas water heaters is reversed and electric water heaters dominate new construction (example in the Lower Mainland gas water heaters are forecast to capture 74% of the new construction market-this threat analysis assumes that gas' share will be reduced to 19%).
Improved Electric Space Heating Control	No impact on existing housing stock	<ul style="list-style-type: none"> - No impact on housing types other than SFDs - Assumes reduction in market share of gas space heating in Lower Mainland for SFDs from 57% to 37%. - Reduction in gas SFD market in interior from 55% to 40%¹. - Reduction in Vancouver Island market by 11%.
Geothermal	No impact on existing housing stock	<ul style="list-style-type: none"> - Impact on SFDs and High Rises not on other housing types. - Threat assumes 5% reduction in gas heat market share for all regions.
Wood Pellets	0.5 % reduction in SFD space heating for Lower Mainland and Vancouver Island, 1% for Interior. No impact for other housing types.	For new construction 0.5% reduction in expected space heating load for SFD in Lower Mainland, 1.0 % on Vancouver Island and 2.0% in the interior
Electric Fireplaces vs. Gas Fireplaces	No impact on existing housing stock.	<ul style="list-style-type: none"> - No impact on new SFDs - Assumes forecast for gas fireplaces in MURBs is reduced by 50%.

Sections eight and nine provide further explanation to the estimated Opportunities and Threat values.

2.2 Commercial Opportunities and Threats

¹ Market share is based on 2006 BC Hydro 2006 Residential Use Study. Reported market share of is derived from regional breakdown of forced-air only gas units.

There are a limited number of opportunities to increase Terasen gas sales in the commercial sector; the largest involves cogeneration and district heating. The table below indicates the magnitude.

Table 5 – Estimate of Increase in Commercial Annual Sales Due to Opportunities (PJ/yr)

Opportunity	Lower Mainland	Interior	Vancouver Island	Opportunities Total
Small-Scale Cogeneration at Commercial facilities	1.3	0.1	0.1	1.5
District Heating and Cooling – Integrated Complexes	0.2	0.1	0.1	0.4
Jacuzzi-Hot Tubs	0.1	< 0.1	< 0.1	0.1
Instantaneous Hot Water	< 0.1	< 0.1	< 0.1	0.1
Total	1.6	0.3	< 0.3	2.1

The table below provides explanations of the impact analysis for the commercial opportunities and section 8.2 provides more extensive explanations.

Table 6 - Commercial Opportunity Impact Explanation Summary

Opportunity	Retrofit Explanations	New Construction
Small-Scale Cogeneration at Commercial facilities	There is a potential for small-scale cogeneration projects connected to base-loaded water heating at commercial and institutional facilities. Economics appear reasonable if gas price risk can be dealt with.	Similar to retrofit opportunities, except smaller market.
District Heating and Cooling – Integrated Complexes	Opportunity to expand heating/cooling systems of existing hospital/institutional district systems.	New commercial developments which are close to institutional district systems would be target market.
Hot Tubs	In certain sub-segments in the commercial sector there is an opportunity to increase the number of gas fired hot tubs. The hotel and the recreation sectors are prime examples.	Opportunity in new construction is similar to retrofit opportunity
Instantaneous Hot Water	There is an opportunity to promote instantaneous gas water heaters in the commercial sector because there are a number of applications which require relatively small amounts of hot water for short periods of time. Hotels and recreation facilities are examples.	Opportunity in new construction is similar to retrofit opportunity

The threats in the commercial sector are not as significant as the ones in the residential sector. Three threats were identified and their potential impacts are outlined in the table below.

Table 7 - Estimate of Decrease in Commercial Annual Sales Due to Threats (PJ/yr)

Threats	Lower Mainland	Interior	Vancouver Island	Threats Total
Air-to-Air Heat Pumps	1.0	0.6	0.1	1.7
Electric Control	0.6	0.3	0.1	1.0
Geo-Exchange	0.1	< 0.1	< 0.1	0.2
Total	1.8	0.9	0.2	2.8

The table below provides explanations of the threats and section 9.2 provides more extensive explanations.

Table 8 – Commercial Threat Impact Explanation Summary

Threat	Retrofit Explanations	New Construction
Air-to-Air Heat Pumps	Impact assumes five percent loss of natural gas load in commercial sub-sectors with small to medium size buildings	Impact assumes 20% loss of natural gas space heating load in commercial sub-sectors with small to medium size buildings.
Electric Control	No impact is assumed in retrofit market	Impact assumes 30% loss of natural gas space heating load in most commercial sub-sectors.
Geo-Exchange	No impact is assumed in retrofit market	Impact assumes 20% loss of natural gas space heating load in the commercial sub-sectors where large buildings tend to dominate

2.3 Industrial Opportunities and Threats

There are significant opportunities in the industrial sector to increase natural gas sales, mainly in the area of cogeneration.

Table 9 - Estimate of Increase in Industrial Annual Sales Due to Opportunities (PJ/yr)

Opportunity	Lower Mainland	Interior	Vancouver Island	Opportunities Total
General Industrial Cogeneration	0.6	1.6	0.6	2.8
Greenhouse Cogeneration	2.0	-	-	2.0
Gas Fired Infrared	<.1	0.1	<.1	0.2
Total	2.7	1.7	0.7	5.0

The following table provides explanations of these opportunities.

Table 10 – Industrial Opportunity Impact Explanation Summary

Opportunity	Retrofit Explanations	New Construction
General Industrial Cogeneration	A portion of existing boiler supplied process steam generation could be replaced by cogeneration projects which would generate steam and electricity.	The new construction component was ignored.
Greenhouse Cogeneration	Greenhouses in the Lower Mainland are interested in cogeneration. They can probably be justified on an economic basis if BC Hydro gives them the appropriate transmission benefits for their location.	The new construction component was ignored because there is some uncertainty as to the rate of growth for the greenhouse industry.
Gas Fired Infrared	A small percentage of industrial comfort heating load could be supplied by gas fired infrared systems.	The new construction component was ignored.

There is a general trend in the industrial sector to reduce natural gas use.
The Table below summarizes an estimate of the sales impact of these reductions.

Table 11 - Estimate of Decrease in Industrial Annual Sales Due to Threats – (PJ/vr)

Threats	Lower Mainland	Interior	Vancouver Island	Threats Total
Wood Waste Boilers	2.5	4.4	2.6	9.4
Lime Kiln Alternatives	Estimate is for all of B.C.			1.0
Wood Waste Kilns	< 0.1	0.2	< 0.1	0.3
Total	2.6	4.6	2.7	10.7

The table below provides explanations for these threats and section 9.3 provides more extensive explanations.

Table 12 – Industrial Threat Impact Explanation Summary

Threat	Retrofit Explanations	New Construction
Wood Waste Boilers	Assume five percent reduction in gas use in pulp mill power boilers due to improved boiler control.	New construction impact was ignored because of uncertain growth in pulp and paper industry.
Lime Kiln Alternatives	Pulp mills are investigating alternative fuels to natural gas for lime kilns. It is estimated that two of them will convert to alternative fuels within five years.	New construction impact was ignored because of uncertain growth in pulp and paper industry.
Wood Waste Kilns	Assumes 20 % reduction in the number of gas fired kilns over the next five years.	New construction impact was ignored.

3 BC DOMESTIC ENERGY USE

The purpose of this section is to provide a background understanding of the overall energy use in British Columbia in terms of fuel type, customer sector and end-use. The fuel types are electricity, natural gas, oil/propane, wood, coal/other. The customer sectors are Residential, Commercial/Institutional and Industrial, while the end-use breakdowns vary from customer sector to customer sector.

In compiling the data, an attempt was made to use the most recent data available which was generally 2005 or 2004.

3.1 Overall Energy Use Breakdown

The table below indicates the total energy used directly by consumers in British Columbia. The natural gas used to produce electricity is not included in this analysis. Natural Gas is a dominant fuel for all three sectors.

Table 13 - 2004 Annual BC Total Energy Consumption by Sector and Fuel Source (PJ).

Sector	All Fuel Sources		Electricity		Natural Gas*		Wood		Oil/Propane		Coal/Other	
Residential	168.6	100%	63.1	37%	96.7	57%	6.6	4%	1.2	1%	1.0	1%
Commercial/Institutional	119.0	100%	50.1	42%	55.3	46%	-	-	10.5	9%	3.1	3%

Industrial	393.7	100%	109.7	28%	105.9	27%	162.1	41%	-	-	16.0	4%
Total	681.3		222.9		257.9		168.7		11.7		20.1	

Sources: Natural Resources Canada. Secondary Energy Use and GHG Emissions by Energy Source – British Columbia

Notes: *includes reported energy use and uses not purchased from regulated utilities.

Figures 1 and 2 provide an overview of the BC Energy Market.

Figure 1 - Overall BC Energy Use by Fuel Source

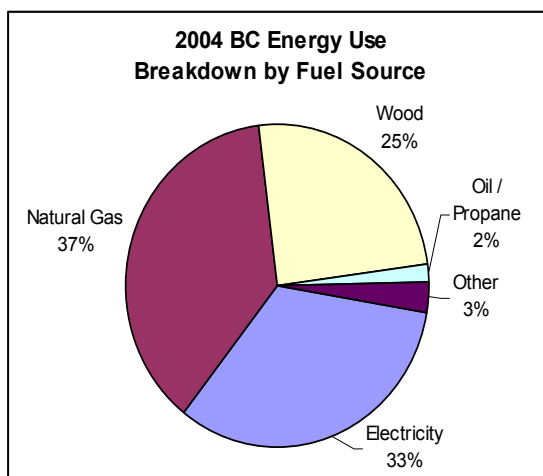
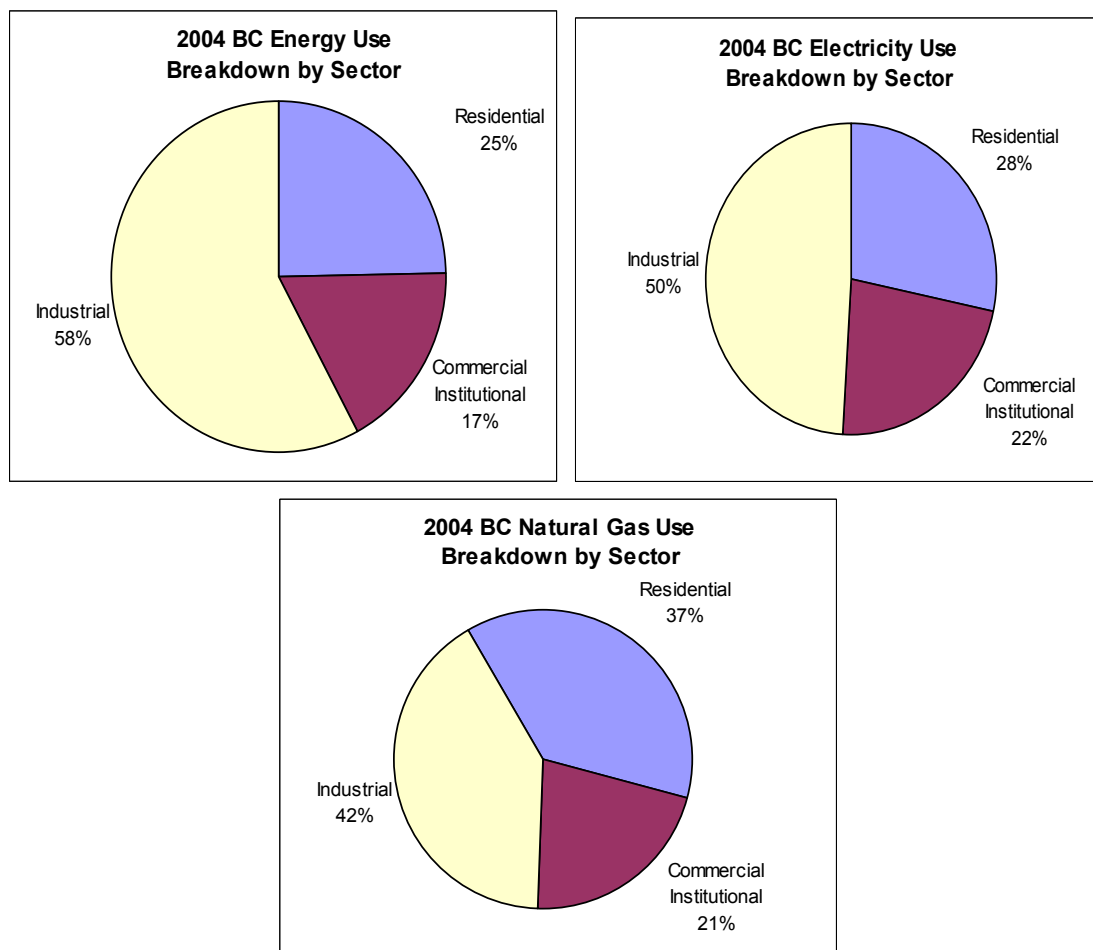


Figure 2 - Overview of BC Energy Market by Sector



3.2 Breakdown by Building and Facility Type

The table below provides a breakdown for the Residential sector by housing type. The breakdown for natural gas is only provided for the Terasen Gas served regions. There is approximately 10 PJ/yr used by the residential sector in regions not served by Terasen Gas, mostly Pacific Northern Gas service territory.

From a competitive market assessment perspective these sector breakdowns are important because they provide a background analysis to assist in estimating what fuel switches could occur in the future; from a sector basis.

Table 14 - Annual Residential Sector Consumption by Building Type and Fuel Source (PJ)

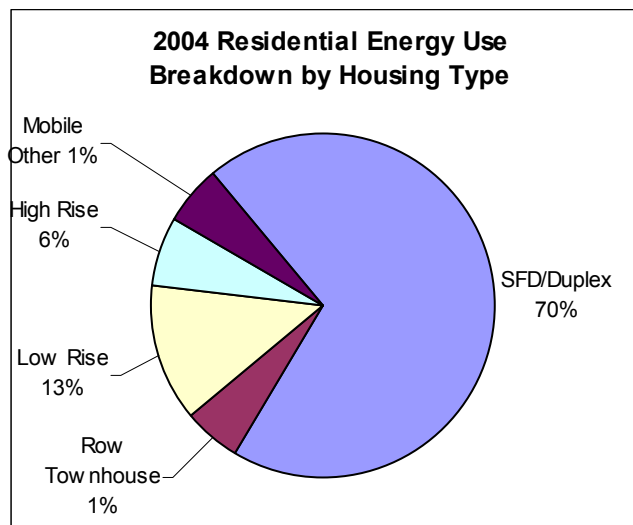
Residential Building Type	All Fuel Sources		Electricity*		Natural Gas **		Wood & Other ***		Oil†	
SFD/Duplex	117.7	100%	43.5	37%	65.8	56%	7.6	6%	0.8	1%
Row/Townhouses	8.7	100%	3.8	44%	4.8	56%	-	-	0.1	1%
Low Rise	22.3	100%	7.6	34%	14.5	65%	-	-	0.2	1%
High Rise	10.6	100%	3.8	36%	6.8	64%	-	-	0.1	1%
Mobile/Other	9.3	100%	4.4	47%	4.8	52%	-	-	0.1	1%
Total	168.6	-	63.1	-	96.7	-	7.6	-	1.2	-

Source: BC Hydro CPR 2002 – Residential Sector

Notes: Terasen Gas – 2004 Conservation Potential Review – Residential Sector
 *Building Type breakdown is same as BC Hydro 2002 CPR – Residential Sector
 **Building Type breakdown is same as Terasen Gas 2004 CPR – Residential Sector
 ***Assumption: wood and other fuel used entirely in SFD.
 †Building Type Breakdown same as Terasen Gas 2004 CPR - Residential Sector

Figure 3 below provides a breakdown for the Residential sector by housing type. The breakdown is provided by all fuel sources.

Figure 3 - Residential Energy Use by Housing Type



The table below provides a breakdown by building type for the Commercial/Institutional sector

Table 15 - Annual Commercial/Institutional Sector Consumption by Sub-Sector and Fuel Source (PJ)

Commercial Sub-Sector	All Fuel Sources		Electricity*		Natural Gas**		Wood		Oil***		Other***	
Small Commercial	53.7	100%	24.0	45%	23.8	44%	-	-	4.5	8%	1.3	2%
Recreation Facilities and Other	6.9	100%	-	-	5.5	80%	-	-	1.1	15%	0.3	4%
Large Office	10.0	100%	6.5	65%	2.8	28%	-	-	0.5	5%	0.2	2%
Medium Office	2.9	100%	1.5	52%	1.1	38%	-	-	0.2	7%	0.1	2%
Large Non-Food Retail	7.3	100%	4.5	62%	2.2	30%	-	-	0.4	6%	0.1	2%
Medium Non-Food Retail	1.7	100%	1.0	59%	0.6	33%	-	-	0.1	6%	< 0.1	2%
Food Retail	2.7	100%	2.0	74%	0.6	21%	-	-	0.1	4%	< 0.1	1%
Large Hotel	3.1	100%	1.0	33%	1.7	54%	-	-	0.3	10%	0.1	3%
Medium Hotel/Motel	1.2	100%	0.5	42%	0.6	46%	-	-	0.1	9%	< 0.1	3%
Hospital	1.7	100%	1.0	59%	0.6	33%	-	-	0.1	6%	< 0.1	2%
Nursing Homes	0.9	100%	0.2	22%	0.6	63%	-	-	0.1	12%	< 0.1	4%
Large School	4.9	100%	1.5	30%	2.8	56%	-	-	0.5	11%	0.2	3%
Medium School	3.8	100%	1.0	27%	2.2	59%	-	-	0.4	11%	0.1	3%
University/College	6.1	100%	2.0	33%	3.3	54%	-	-	0.6	10%	0.2	3%
Restaurant/Tavern	3.6	100%	1.5	42%	1.7	46%	-	-	0.3	9%	0.1	3%
Warehouse/Wholesale	4.3	100%	1.5	35%	2.2	52%	-	-	0.4	10%	0.1	3%

Commercial Sub-Sector	All Fuel Sources		Electricity*		Natural Gas**		Wood		Oil***		Other***	
Mixed Use	1.0	100%	0.3	31%	0.6	56%	-	-	0.1	11%	< 0.1	3%
Miscellaneous	3.4	100%	-	-	2.8	80%	-	-	0.5	15%	0.2	4%
Total	119.0	-	50.1	-	55.3	-	n/a		10.5	-	3.1	-

Source: BC Hydro CPR 2002 - Commercial Sector Breakdown by Building Segment (Exhibit E5)

Terasen Gas - 2004 Conservation Potential Review. Commercial Sector (Exhibit E3)

Notes: *Building Type breakdown same as BC Hydro 2002 CPR - Commercial Sector

**Building Type breakdown is same as Terasen Gas 2004 CPR - Commercial Sector.

***Assumption: wood and other fuel building segment breakdown same as Terasen Gas 2004 CPR – Commercial Sector

The table below indicates the energy use breakdown by industry facility type.

Table 16 - Annual Industrial Sector Energy Consumption by Facility Type and Fuel Source (PJ)

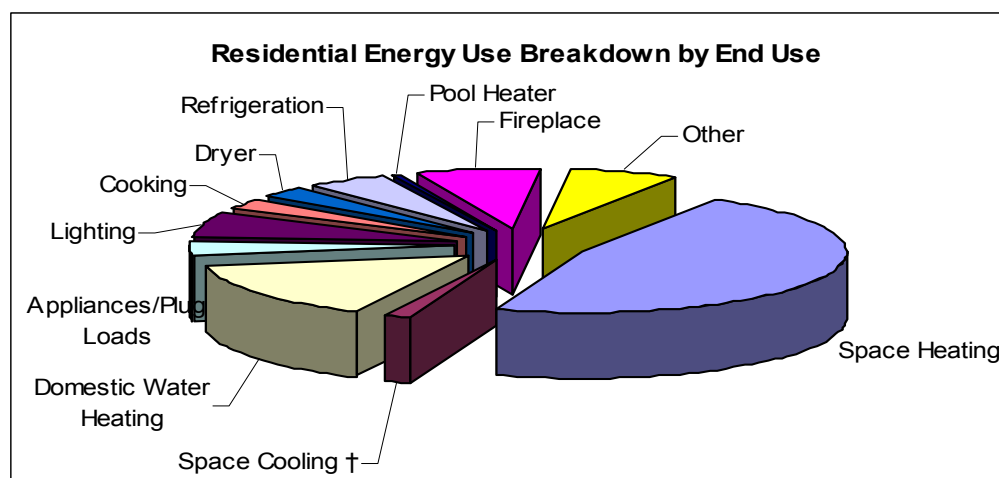
Industrial Facility	All Fuel Sources		Electricity		Natural Gas		Wood		Other	
Pulp and Paper	222.6	100%	34.1	15%	33.2	15%	155.3	70%	-	-
Mining	17.9	100%	10.4	58%	7.5	42%	-	-	-	-
Wood Products	33.8	100%	10.2	30%	16.9	50%	6.8	20%	-	-
Chemicals	32.7	100%	6.0	18%	26.7	82%	-	-	-	-
Petroleum Refining	1.8	100%	1.8	100%	-	-	-	-	-	-
Mfg & Light Industry	46.2	100%	8.6	19%	21.6	47%	-	-	16.0	35%
Alcan/Cominco/FortisBC	38.7	100%	38.7	100%	-	-	-	-	-	-
Total	393.7	-	109.7	-	105.9	-	162.1	-	16.0	-

Sources: *BC Hydro CPR 2002 – Industrial Sector

3.3 End-Use Breakdown

Figure 4 below provides an overall end-use breakdown for the residential sector for all fuel Sources.

Figure 4 - Residential Sector Energy Consumption by End-Use



As further detail to the above figure, the table below indicates the residential end-use breakdown by fuel type.

Table 17 - Residential Sector Energy Consumption by End-Use and Fuel Source (PJ)

Residential End Use	All Fuel Sources		Electricity*		Natural Gas**		Wood****		Oil***		Other***	
Space Heating	79.3	100%	12.9	16%	58.5	74%	6.6	8%	0.7	1%	0.6	1%
Space Cooling †	2.6	100%	2.6	100%	< 0.1	0%	-	-	-	-	-	-
Domestic Water Heating	25.8	100%	5.0	20%	20.3	79%	-	-	0.3	1%	0.2	1%
Appliances/Plug Loads	7.3	100%	7.3	100%	< 0.1	0%	-	-	-	-	-	-
Lighting	10.7	100%	10.7	100%	< 0.1	0%	-	-	-	-	-	-
Cooking	5.1	100%	3.2	61%	1.9	38%	-	-	< 0.1	0%	< 0.1	0%
Dryer	4.6	100%	3.8	83%	0.8	17%	-	-	< 0.1	0%	< 0.1	0%
Refrigeration	8.2	100%	8.2	100%	-	-	< 0.1	0%	-	-	-	-
Pool Heater	1.0	100%	-	-	1.0	98%	-	-	< 0.1	1%	< 0.1	1%
Fireplace	12.6	100%	n/a	-	12.3	98%	-	-	0.2	1%	0.1	1%
Other	11.4	100%	9.5	83%	1.9	17%	-	-	< 0.1	0%	< 0.1	0%
Total	168.6	-	63.1	-	96.7	-	6.6	-	1.2	-	1.0	-

Source: BC Hydro CPR 2002 - Residential Sector Breakdown by Building Segment (Exhibit E5)

Terasen Gas - 2004 Conservation Potential Review. Residential Sector (Exhibit E3)

Notes: *End Use breakdown same as BC Hydro 2002 CPR - Residential Sector

**End Use breakdown is same as Terasen Gas 2004 CPR - Residential Sector.

***Assumption: wood and other fuel building segment breakdown same as Terasen Gas 2004 CPR – Residential Sector

****Paul Willis Assumption

†Includes HVAC

The table below indicates the End-Use breakdown for the Commercial/Institutional sector.

Table 18 - Commercial/Institutional Sector Energy Consumption by End-Use and Fuel Source (PJ)

Commercial/ Institutional End Use	All Fuel Sources		Electricity*		Natural Gas**		Oil/Propane***		Other***	
Space Heating	54.4	100%	2.0	4%	42.0	77%	8.0	15%	2.4	4%
Space Cooling†	9.5	100%	9.5	100%	-	-	-	-	-	-
Water Heating	10.1	100%	0.5	5%	7.7	76%	1.5	14%	0.4	4%
Aux. Equipment & Motors	-	-	-	-	-	-	-	-	-	-
Lighting	24.5	100%	24.5	100%	-	-	-	-	-	-
Street Lighting	-	-	-	-	-	-	-	-	-	-
Commercial Cooking	6.9	100%	-	-	5.5	80%	1.1	15%	0.3	4%
Office Equipment and Plug loads	5.0	100%	5.0	100%	-	-	-	-	-	-
Food & Refrigeration	3.5	100%	3.5	100%	-	-	-	-	-	-
Miscellaneous	5.0	100%	5.0	100%	-	-	-	-	-	-
Total	119.0	-	50.1	-	55.3	-	10.5	-	3.1	-

Source: BC Hydro CPR 2002 - Commercial Sector Breakdown by Building Segment (Exhibit E5)

Terasen Gas - 2004 Conservation Potential Review. Commercial Sector (Exhibit E3)

Notes: *End Use breakdown same as BC Hydro 2002 CPR - Commercial Sector

**End Use breakdown is same as Terasen Gas 2004 CPR - Commercial Sector.

***Assumption: wood and other fuel building segment breakdown same as Terasen Gas 2004 CPR – Commercial Sector

†Includes HVAC

The following table is the end-use breakdown by fuel type for the industrial sector.

Table 19 - Industrial Sector Energy Consumption by End-Use and Fuel Source (PJ)

Industrial End Use	All Fuel Sources		Electricity		Natural Gas		Wood		Other	
Motor Drive Systems	63.0	100%	63.0	100%	-	-	-	-	-	-
Electric Process	35.7	100%	35.7	100%	-	-	-	-	-	-
Boilers	229.1	100%	-	-	70.5	31%	155.3	68%	3.2	1%
Drying Equipment	37.8	100%	-	-	31.0	82%	6.8	18%	-	-
Industrial Process Heat (non-steam)	22.6	100%	5.5	24%	4.3	19%	-	-	12.8	57%
Light	5.5	100%	5.5	100%	-	-	-	-	-	-
Total	393,703	-	109,700	-	105,900	-	162,100	-	16,000	-

Source: BC Hydro CPR 2002 – Industrial Sector Breakdown by Building Segment

Terasen Gas – 2004 Conservation Potential Review – Manufacturing Sector

4 ENERGY USE TRENDS AND MAJOR FORECAST ELEMENTS

4.1 Sales Forecast

The Resource Plans and Annual Review reports for Terasen Gas Inc. (TGI) and Terasen Gas Vancouver Island (TGVI) provide existing gas sales and a forecast sales growth rate for Terasen Gas per region. Table 20 indicates the sales volume in 2005, and Table 21 indicates the projected growth in sales over the period 2006 to 2015.

Table 20 – Annual 2005 Terasen Gas Sales for TGI and TGVI (PJs)

	Lower Mainland	Interior	Vancouver Island	Total
Residential	71.5	21.8	5.7	99.0
Commercial	26.7	9.5	8.3	44.4
Industrial	23.0	27.8	11.0	61.7
Total	121.1	59.0	25.0	205.2

Table 21 – Forecast Growth in Sales 2006 to 2015

	Lower Mainland		Interior		Vancouver Island		% Change	
	Growth (PJ/yr)	% Change	Growth (PJ/yr)	% Change	Growth (PJ/yr)	% Change	Growth (PJ/yr)	% Change
Residential	11.7	16.4%	2.6	12.0%	1.7	29.1%	16.0	16.2%
Commercial	1.1	4.2%	1.1	11.7%	2.4	29.1%	4.6	10.4%
Industrial	0.6	2.6%	0.1	0.4%	0.2	1.4%	0.9	1.4%
Total	13.4	11.1%	3.8	6.5%	4.2	16.9%	21.5	10.5%

4.1.1 Residential - Lower Mainland and Interior

The main assumption behind the assumed growth in sales to residential customers in the TGI jurisdiction is the strong current housing boom. The growth forecast assumes 12,000 to 14,000 new customer additions per year most of which will be new houses. On a use per customer basis the forecast assumes very little change for the next 10-year period. There was a slight decline in actual use per customer in the 2003 to 2005 period attributed mainly to the price spike in 2001.

The forecast was based on a forecast wholesale natural gas price of \$8.00 U.S per million Btu in 2006 declining to \$6.00 U.S. per million Btu in 2011 and staying relatively flat for the following 10 years. All prices were in 2006 Constant dollars. The most important aspect of the price forecast is the predicted competitiveness of natural gas with electricity. The forecast assumed a recent proposed BC Hydro rate increase of 7.5% by April 2007. Recently the BCUC has reduced this projected increase by about 2%.

It should be noted that the forecast does not appear to assume that there will be a significant impact due to:

- A trend from single family dwellings to multi-family units, and
- An apparent change in market share from natural gas to electricity in multi-family dwellings.

The TGI Resource Plan mentions the attractiveness from a sustainability perspective of district heating systems. This technology would result in an increase in natural gas use and could offset the apparent loss in the multi-family market.

Most of the industrial load in TGI's jurisdiction is transportation customers. The forecast indicates almost no change in this market segment over the next ten years. One of the main reasons for a status quo forecast is the projected increase in use of wood waste within the forest and agricultural industries.

4.1.2 Residential - Vancouver Island

Natural gas became available to the Vancouver Island (VI) market in 1991 and there was a large increase in natural gas usage from 1991 to 1998. From 1998 to the present, the growth has stabilized at about 1200 new customers per year.

The 2006 TGVI Resource Plan indicated that in 2003-2004 there were 1,400 new accounts per year and the Resource Plan forecasts that new account addition will level off to 1,200 per year over the long term. In percent growth terms, the long-term growth is forecast to be slightly over two percent.

As with the TGI Resource Plan the forecast does not appear to assume that there will be a significant impact due to:

- A trend from single family dwellings to multi-family units, and
- An apparent change in market share from natural gas to electricity in multi-family dwellings.

4.2 Commercial – Lower Mainland, Interior and Vancouver Island

The Commercial sector consists of a wide variety of types of customers from small stores to large universities. Growth in this sector normally follows general economic growth and due to an expected strong growth in the British Columbia economy, this sector is forecast to have a significant expansion over the next 10 years.

The following are key trends within this sector:

- A long-term shift in BC from a goods-based to a more service-based economy. From an energy perspective this means a shift away from process energy demands and more towards building services.
- An aging and growing population, resulting in a growing demand in health care services and certain types of recreational facilities.
- The 2010 Olympics is at the forefront of major infrastructure and service growth.
- The growing trend towards urbanization will result in more building complexes being integrated communities, which will include residential units, stores, recreational facilities and health care services.
- Tourism is expected to continue to grow and be a larger component of our economy; there will be many new large hotel complexes and the trend will be towards luxury type facilities.
- Due to aging population, expanded tourism, climate change and a general interest in more comfortable buildings there is going to be an increasing demand for air conditioning.
- Being "green" is going to be a significant factor. Many sub-sectors within the overall commercial/institutional sector are affected by changing societal values and society's current strong interest in environmental issues is going to be important to educational institutions, hotels, and public recreational facilities.

4.3 Industrial Sector – Lower Mainland, Interior and Vancouver Island

4.3.1 *Pulp and Paper*

The Pulp and Paper industry and the associated electro-chemicals are expected to have at best stagnant growth over the next ten years. The Woodfibre pulp mill at Squamish recently shutdown and there is expected to be further rationalization in the industry. The pulp and paper market is world-wide and mills in B.C. are competing on that basis. New pulp mills being built in Asia and South America are relatively large at 3,000 tons of paper per day (compared to mills in BC at around 1,000 tons/day) and considerably more efficient because of their use of state of the art equipment.

From an energy perspective, BC mills are expected to further reduce their consumption of natural gas. Catalyst over the last 10 years have re-built and purchased a new boiler at their mills in Port Alberni and Powell River so that both of these facilities have significantly reduced their consumption of natural gas. The Vancouver Island Joint Venture consisting of the six pulp mills on the Sunshine Coast and Vancouver Island have reduced their gas usage by 50% over the last 10 years. All the pulp mills are continually looking at methods for reducing the gas consumption in their Power/Steam boilers and are expected to further reduce the amount that they are presently using.

Another major use of natural gas in some pulp mills is for lime kilns at kraft mills. Mills are also seriously investigating methods for using alternative fuels for energy intensive applications. For example, they are looking at Petroleum Coke and woodwaste by means of a gasification process.

4.3.2 *Wood Products*

The wood products industry in terms of production is expected to be relatively stable over the next seven years with some possibility of expansion. The expansion would be due to the need to harvest pine beetle kill trees at an accelerated rate. However, due to the current recession in U.S. house building there is a question of how the product from the accelerated production could be sold at a profitable value. After seven years, it appears that there could be a significant drop-off in production due to the long-term impact of the Pine Beetle Kill. Eventually the Annual Allowable Cut will have to be drastically reduced.

The wood products industry uses a considerable amount of natural gas for lumber dry kilns, veneer and oriented strand board dryers. It is expected that some of this use is going to be replaced by wood waste units. Tolko's Heffley plant has installed a wood waste gasifier to supply heat to one of its veneer dryers and has significantly reduced its gas consumption. There is a possibility of similar types of facilities over the next 10-years. There is also the potential for more energy plants that transfer heat from wood waste combustion units by means of a circulating hot oil system. In addition, due to BC Hydro's announced intention to purchase electricity from plants that use wood waste, there is the potential for cogeneration facilities that would supply steam to lumber kilns.

4.3.3 *Mining*

The mining industry is experiencing a rapid expansion at the present time due to the increase in the price of copper, gold, molybdenum and coal. It is difficult to forecast how extensive and long this growth will last. Mining facilities use natural gas mainly for drying concentrate or in the case of coal, the clean product that is exported. If natural gas is available, it is expected that it will continue to be the fuel of choice.

5 ENERGY CHOICES

Customers have energy choices and these choice areas and items are the keys to the opportunities and threats that face the natural gas market. Customer decision factors are governed by comfort, costs, interest in the environment, reliability, safety, ease of use and prestige or appearance.

5.1 Residential

With the residential sector, the energy choices are often made by developers and real estate marketers. They are ultimately affected by what individual customers value but the decisions that are made at the development stage are based on what the marketers think customers will be willing to purchase. A good example is fireplaces. Developers will select gas fireplaces if they believe that they will add to the purchase attractiveness and selling price of a residence.

5.1.1 *Space Heating*

The table below indicates the space heating options for residential units. The units with and without fireplaces are separated because a fireplace can significantly affect the natural gas used by the major space heating unit.

Table 22 - Residential Space Heating Options

Auxiliary Space Heating	Major Space Heating Equipment
Units with Gas Fireplace	Gas Force Air
	Gas Hydronic
	Electric Baseboard
	Electric Forced Air
	Electric Radiant Surface
	Ground Source Heat Pump
	Air Source Heat Pump
	Hot Air Other
	Hydronic Other
Units with No Gas Fireplace	Gas Force Air
	Gas Hydronic
	Electric Baseboard
	Electric Forced Air
	Electric Radiant Surface
	Ground Source Heat Pump
	Air Source Heat Pump
	Hot Air Other
	Hydronic Other

5.1.2 *Space Cooling*

For residential use, it is suggested that the only choices involve electricity use:

- Air to air heat pump/conditioning
- Geo-exchange

The only impact that these choices have on the natural gas market is that if air conditioning is required, it does effectively reduce the capital cost of an electric heat pump or geo-exchange system.

5.1.3 Domestic Water Heating

The choices for Domestic Water Heating are:

- Natural gas
- Electric
- Solar
- Geo-exchange system with temperature boost.

5.1.4 Appliance/Plug Loads

These loads do not involve natural gas as a choice. There however, is an indirect impact in that as plug loads increase in a residence, they reduce the need for space heating.

5.1.5 Lighting

Lighting essentially involves electricity, although there is a market for outdoor gas lamps.

5.1.6 Pool/Spa heaters

The choices are:

- Natural Gas
- Electric
- Solar

5.2 Commercial/Institutional

5.2.1 Space Heating

The space heating choices for this sector are very much affected by building type but considering the whole sector, the alternatives are as follows:

- | | |
|--|--------------------------------------|
| • Gas Fired Central Building Boiler | • Gas Fired District Heating System |
| • Electric Central Building Boiler | • Wood Fired District Heating System |
| • Gas Fired Furnace (mostly roof top unit) | • Geo-exchange System |
| • Electric Heat Pumps Unit | • Electric Baseboard |

5.2.2 Space Cooling

The alternatives are:

- | | |
|------------------------------------|--|
| • Electric Central Chiller | • Geo-exchange System |
| • Roof-Top Or Window Electric Unit | • Gas Fired (Steam) Absorption Chiller |

5.2.3 Domestic Water heating

The choices are:

- Sub-system of gas fired central boiler system
- Locational electric unit
- Solar in certain situations

5.2.4 Commercial Cooking

The dominant choices are:

- Gas fired unit
- Electric unit
- Propane unit where natural gas is not available.

5.3 Industrial Sector

5.3.1 Boilers

The dominant choices are gas fired or wood waste units.

5.3.2 Drying Equipment

The options vary according to type of facility; the table below indicates the choices versus industrial facility type:

Table 23 - Industrial Drying Equipment Options

Sector	Equipment Alternatives
Pulp and Paper	Gas Fired Pulp Dryers
	Steam/Wood Waste
	Cogen Gas Fired Pulp Dryers
Mining	Gas Fired Coal Dryers
	Coal Fired Dryers
	Gas Fired Ore Dryers
Wood Products	Gas Fired Lumber And Veneer Kilns/Dryers
	Wood Waste Energy Systems
	Wood Waste Gasifiers
	Steam Kilns
Mfg & Light Industry	Stone Dryers For Asphalt – Gas Fired
	Stone Dryers For Asphalt – Oil Fired

5.3.3 Industrial Process Heat

The table below indicates the different options for specific industrial facilities.

Table 24 - Industrial Process Heat Options

Industrial Facility	Equipment Option
Cement Industry	Gas Fired Kilns
	Coal Fired Kilns
Foundries	Electric Furnaces
	Gas Furnaces

6 MODELLING APPROACH

The model structure that was used to analyze opportunities and threats is provided in Appendix A. Using this model estimates were developed of the existing market shares of energy equipment.

The model was then used to provide estimates of deviations from a base condition. An opportunity would be a trend which would lead to increased natural gas use. An example is a situation where BC Hydro and Terasen Gas provide a combined incentive to encourage customers to select gas fired water heaters as opposed to electric water heaters. The model would be used to estimate the magnitude in annual gas sales of such an opportunity.

After the model is used to estimate the value of an opportunity or threat on a Province wide basis, the value would be further broken down into regional estimates.

7 TERASEN RESOURCE PLAN DISCUSSION

This Competitive Market Assessment generally uses Terasen Gas' 2006 Resource Plan forecasts as the base case. In other words, opportunities for more gas sales are analyzed in terms of an increase compared to the forecast base case and, threats which would reduce gas sales are analyzed in terms of a decrease compared to the base case. However, Willis in reviewing the forecast suggests that there are two detailed methodology items in which for future forecasts further study would be useful:

- Estimating the growth in accounts on a household basis, and
- Gas use per account.

On page 41 of the TGI 2006 Resource Plan, Section 3.3.3 indicates that the primary predictor variable used in the account additions model is household growth rate by Local Health Authority. It is suggested that household growth relates to the full spectrum of housing types: single family, townhouses, and apartments. As indicated on Page 33 of the Resource Plan in the section on electricity, it is recognized that there is a strong shift towards apartments and townhouses (MURBs) from Single Family Dwellings (SFDs). One of the concerns from a forecasting perspective is that the recent housing boom in Vancouver may mask some long-term trends in Terasen's gas sales. In other words, due to the recent boom there has been a significant increase in SFDs, but on a ten-year horizon the growth in SFDs may be much lower than expected due to the shift towards MURBs. This has significant implication to Terasen in that at the present time, their share of the MURB space heating market is relatively low.

Accordingly, Terasen Gas' opportunity for increased sales due to an increased share of the MURB market cannot be compared directly to the Resource Plan forecast because the forecast for gas sales to this specific market is not addressed separately in the Resource Plan.

The other item is gas use per account. In Appendix E of Terasen Gas' 2006 Resource Plan (Coastal Region, Page E-1), the annual use rate per customer per rate class is listed as being relatively flat over the long-term at 106.7 GJ. However, on Page 43 of the Resource Plan, it indicates that on a normalized basis there has been a decline in use per account from 103.1 to 97.4 from 2003 to 2005. It is recognized that the relatively sharp drop in 2005 was due in part to customer reaction to recent price increases. However, considering upcoming legislation on the use of high-efficiency furnaces for new homes, and eventual need for replacement furnaces for existing homes, this general trend of a reduction in use per account will most likely continue. Accordingly even if the use per account was frozen at 98 GJ, the long term forecast based on 106.7 GJ per residential coastal region customers appears to be approximately 9% too high (106.7/98).

The values for the Opportunities and Threats in this Competitive Market Assessment should still be considered with respect to the forecast values. For example, a threat of a 0.5 PJ/year decrease should be considered as a reduction in the forecast sales amount. However, it should be noted that there is an overriding question on the forecast in terms of this use per account issue.

8 OPPORTUNITIES ANALYSIS

Despite a dramatic pricing change, natural gas still has a number of advantages which provide some opportunities for increasing gas sales. Most of these “Opportunities” are due to the capacity advantage of natural gas. At the household level or the regional level, energy capacity is much less expensive than electricity. In a detached house, a natural gas water heaters provide faster recovery than electric because it has much more heating capacity. At the regional level, it is usually much easier and less costly to install an additional gas pipeline than an additional high voltage transmission line.

In analyzing opportunities the following was taken into consideration:

- Size of target market (for example space heating and domestic hot water are the two largest market segments in terms of energy sold)
- Market evidence that natural gas has been promoted and accepted by customer groups (for example, it is known that customers do choose gas water heaters because of their fast response time).
- Equipment and installation cost barriers (since the installation of natural gas appliances is often more expensive than corresponding electric alternatives)
- Market inertia and distribution infrastructure (how easily can sales of a particular piece of equipment be increased in terms of sales and delivery effort).

Market and cost information for the list of opportunities was obtained through numerous site visits to new developments in the lower mainland; interviews with developers, HVAC contractors, retail customer service representatives and Terasen Gas staff.

The fact that natural gas is an energy source that can address the energy capacity needs of the Lower Mainland and Vancouver Island is important with respect to provincial energy planning. The major part of British Columbia’s energy requirements is in the Lower Mainland and the southern part of Vancouver Island. However, the major sources of energy are in the interior and north part of the province. The British Columbia Transmission Corporation (BCTC) is presently studying alternatives to meeting the need for increased transmission capacity into the Lower Mainland.

The following is a quotation from the BCTC web site. “The transmission circuits that bring power from where it is generated in the BC Interior to the Lower Mainland are some of the most critical paths in the transmission grid. The amount of electricity transferred on these circuits continues to be high and with potential increases in generation resources located in the North and the Southern Interior, the capacity of these vital paths will be maximized”.

In considering options for meeting the Lower Mainland capacity needs, it is suggested that fuel choice policy should be considered. For example, a policy of maximizing natural gas use relative to electricity use could have a significant impact on reducing the electricity capacity dilemma. However, the current uneven electricity-natural gas pricing structure will tend to maximize electricity consumption relative to natural gas use, further stressing the electricity capacity situation.

8.1 Residential

8.1.1 Increase in Market Share for Natural Gas Water Heater- Tanks

The table below indicates a potential increase in annual natural gas sales for each region if the market share for natural gas water heaters was increased relative to electric water heaters.

Table 25 - Impact of Natural Gas Water Heater Program (PJ/yr)

	Retrofit	New Construction
Lower Mainland	0.5	0.1
Interior	0.2	0.3
Vancouver Island	0.2	0.7
Total	0.9	1.1

Retrofit

The opportunity impact values in the table above are based on converting five percent of the existing Single Family Dwelling market to gas water heaters over a five-year period. It is suggested that an aggressive promotional campaign with a moderate incentive could persuade consumers to convert to gas water heaters at the time that their electric heater needs replacement.

New Construction

The new construction impact values were based on increasing the new market share from 74% to 80% in the Lower Mainland, from 29% to 80% on Vancouver Island and from 51% to 80% in the interior. Our analysis indicates that the existing market share for gas water heaters in the interior and Vancouver Island is significantly lower than in the Lower Mainland.

Table 26 - Gas and Electric Water Heaters - Annual Energy Costs

	Gas Water Heaters Mid-Efficiency	Electric Mid-Efficiency
Lower Mainland	\$282	\$299
Interior	\$231	\$245
Vancouver Island	\$281	\$245

Capital and installation costs are provided in Appendix C. The assumptions used in calculating annual energy costs are provided in Appendix D.

Table 27 –Gas and Electric Water Heater – Cost Assumptions

	Comments
Initial Cost Comparison	The equipment cost of gas and electric water heaters is approximately the same with prices ranging between \$400 to \$600 depending on the model and the distributor.

	Comments
Installation Costs	The installation cost difference for new construction is not significant if B-Vents can be used (\$150 per house). New regulations will require high efficiency furnaces to be direct vented and it is estimated that the difference will be \$500 to \$1,000. In the case of retrofits, if B-venting is possible the installation difference will be approximately \$500. If B-venting is not possible, the difference will be in the order of \$1,000.
Annual Operation and Maintenance	It is assumed that the operating and maintenance costs for gas and electric will be similar.

8.1.2 Multi Unit Residential Building (MURB) Market

Most of the low-rise and high-rise space heating market is going electric. One of the main reasons is the normal common gas metering arrangement for all the suites in a building. In this arrangement, the gas costs are shared equally among all suites within a strata-title complex. This can be inherently unfair because prudent users of fireplaces will pay as much as wasteful users in the same building. Terasen is promoting and facilitating individual suite metering.

The MURB market has other challenges with respect to natural gas versus electricity. Openings in the building envelope for fireplace exhaust, is an example of the specific challenge in this market segment. Architects and building design engineers are very conscious of potential water ingress to buildings and reducing envelope openings tends to reduce the risk. Another challenge, is building construction cost, electric baseboards are considerably less expensive than hydronic heating systems.

However, there are “lifestyle” advantages that can be promoted such as gas fireplaces and gas cooking. The table below is an estimate of the impact in added gas sales if low-rise and high-rise new construction market share for gas space heating could be increased from 5% to 50%.

Table 28 - Impact of Increasing Natural Gas Share of MURB (PJ/yr)

	Retrofit	New Construction
Lower Mainland	-	1.5
Interior	-	0.2
Vancouver Island	-	0.1
Total	-	1.9

Table 29 – Economic Comparison Gas Hydronic vs. Electric Resistance Heating

	Comments
Building heating infrastructure	The gas fired hydronic heating is \$4.00 to \$6.00 per foot more expensive than electric resistance heating.
Annual Operation and Maintenance	Hydronic heating will also have a higher annual maintenance cost but for a large building this will be insignificant.

8.1.3 Increase in Market Share for Natural Gas Water Heater – Instantaneous

Instantaneous or demand water heaters are also referred to as tankless systems since they do not continuously heat and store water. A gas burner or electric element automatically ignites when a faucet is turned on and hot water is delivered on demand, thus allowing for a reduction in stand-by heat losses. While gas demand heaters typically have a higher hot water output than electric models, their one overall limitation is the flow rate. Heated water flow rates range from 7 to 15 litres/minute (US DOE, 1995). As a result, demand water heaters are best suited for households with low simultaneous demands. The initial unit cost is higher than either electric or natural gas conventional storage water heaters, but operating costs for the gas demand models are lower. Fuel consumption for gas-powered units can be higher if pilots remain lit, but units are now produced with electronic ignitions that reduce this cost.

The table below indicates a potential increase in annual natural gas sales for each region if the market share for natural gas water heaters was increased relative to electric water heaters. It is also suggested that an incentive could persuade consumers to select gas water heaters.

Table 30 - Impact of Instantaneous Natural Gas Water Heater Program (PJ/yr)

	Retrofit	New Construction
Lower Mainland	0.2	0.1
Interior	0.1	0.2
Vancouver Island	0.1	0.6
Total	0.4	0.8

Instantaneous water heaters are new to the residential market in BC and we were not able to obtain data on their uptake within that market. A number of field visits to various retail stores has yielded anecdotal information that customers have been installing them as secondary uses.

The opportunity impact values in the table above are based on converting approximately 2% of the existing single family dwelling market to instantaneous gas water heaters over a five-year period. For new construction in the Lower Mainland it was assumed that the market share for gas water heaters could be increased from 74% to 80%, for Vancouver Island 29% to 70% and for Vancouver Island 51% to 70%. It is suggested that an aggressive promotional campaign with a moderate incentive could persuade consumers to purchase instantaneous gas water heaters.

For the new construction values, there is a definite overlap between the opportunity for tank gas water heaters and instantaneous gas water heaters.

Table 31 - Gas and Electric Instantaneous Water Heaters - Annual Energy Costs

	Gas Water Heaters	Electric
Lower Mainland	\$190	\$299
Interior	\$156	\$245
Vancouver Island	\$189	\$245

Capital and installation costs are provided in Appendix C. The assumptions used in calculating annual energy costs are provided in Appendix D.

Table 32 –Gas and Electric Instantaneous Water Heater – Cost Assumptions

	Gas Instantaneous Water Heater	Electric
Initial Cost Comparison	\$950	\$700-1,300
Annual Operation and Maintenance	\$100-200	\$100-200

8.1.4 Increase in Market Share for Outdoor Uses (Lighting and Barbeques)

The table below indicates a potential increase in annual natural gas sales for each region if the market share for natural gas outdoor uses was increased.

Outdoor uses of natural gas include the following:

- Patio heaters
- Campfires
- Outdoor fireplaces
- Grills
- Lights

Table 33 - Impact of Outdoor Uses Program (PJ/yr)

	Retrofit	New Construction
Lower Mainland	0.1	0.1
Interior	0.1	< 0.1
Vancouver Island	0.1	0.1
Total	0.2	0.3

Retrofit & New Construction

About 45% of residences in B.C. use gas to fuel various outdoor applications. The bulk of these residences are using gas grills. The above impacts are based on increasing this percentage to 60%.

8.1.5 Increase in Market Share for Natural Gas Clothes Dryers

The table below indicates a potential increase in annual natural gas sales for each region if the market share for natural gas dryers was increased relative to electric dryers.

Table 34 - Impact of Natural Gas Clothes Dryer Program (PJ/yr)

	Retrofit	New Construction
Lower Mainland	0.1	0.1
Interior	< 0.1	< 0.1
Vancouver Island	< 0.1	< 0.1
Total	0.2	0.1

Retrofit

Based on visits to new development in the Lower Mainland and interviews with customer representatives at appliance retail shops, the market share for gas dryers is very low compared to electric dryers. Gas dryer sales

account for approximately 15-20% of total dryer sales at Home Depot. They are most common in low rise buildings with shared laundry facilities. Interviews with sales representatives have noted that the small uptake is likely due to poor promotion of dryers and also because gas dryers are generally less available to the consumer market. The appliance cost for gas dryers is roughly the same as electric dryers (\$699 for gas compared to \$650 for electric, comparable models at Sears).

The impact table above assumed that the market share in existing houses could be increased by five percent.

The table below indicates that the annual energy cost for gas versus electric is approximately the same.

Table 35 - Gas and Electric Dryer - Annual Energy Costs

	Gas Dryer Mid Efficiency	Electric Mid Efficiency
Lower Mainland	\$54	\$61
Interior	\$44	\$61
Vancouver Island	\$56	\$61

Capital and installation costs are provided in Appendix C. The assumptions used in calculating annual energy costs are provided in Appendix D.

Table 36 – Gas and Electric Dryer – Cost Assumptions

	Comments
Equipment and Installation Costs	The cost of gas dryers is assumed to be 10% higher than electric units mainly because the volume of sales for gas units is so low that the distribution costs are higher. The cost of installation will be very similar because the cost of the gas connection and exhaust venting will be similar to the cost of the wiring connection for an electric unit.
Maintenance Costs	No data was collected on the relative maintenance costs between electric and gas. It is assumed that they would be similar.

According to Natural Resources Canada, natural gas dryers can dry approximately three loads with the same amount of energy it takes for an electric dryer to dry 1 load. New gas dryers are designed for efficiency with features such as pilotless ignition and automatic shutoff.

New Construction

For new Single Family Homes, gas dryers will be an easier sell. The promotional program will still probably require some type of incentive. The impact table assumes that a promotional program could capture 20% of the new homes over the next 10 years.

8.1.6 Increase in Market Share for Hot Tubs

The table below indicates a potential increase in annual natural gas sales for each region if the market share for hot tubs was increased.

Table 37 - Impact of Hot tub Program (PJ/yr)

	Retrofit	New Construction
Lower Mainland	0.1	0.1
Interior	0.1	< 0.1
Vancouver Island	< 0.1	< 0.1
Total	0.2	0.1

Retrofit

Approximately 20% of residences in BC have pools and hot tubs heated by natural gas. It is difficult to determine the amount of gas and electricity that is used in Jacuzzi/Hot Tubs, therefore instead of using market share change to calculate the impact, a typical impact was calculated based on increasing the number of units in existing single family homes by 2,000 in the Lower Mainland, 1,000 in the Interior and 500 on Vancouver Island.

New Construction

For the impact on new construction, it was assumed that an additional 1,000 units could be sold in the Lower Mainland, 500 in the interior and 300 on Vancouver Island. It is suggested that an aggressive promotional campaign with a moderate incentive could persuade consumers to purchase gas heaters for their pools and hot tubs.

The table below indicates the annual energy cost:

Table 38 - Gas and Electric Hot Tub - Annual Energy Costs

	Gas	Electric
Lower Mainland	\$635	\$446
Interior	\$677	\$446
Vancouver Island	\$673	\$446

In reviewing the economics for gas versus electric hot tubs, equipment distributors were contacted. Their response was that they were no longer selling gas fired hot tubs because natural gas was considered too expensive a fuel. Accordingly, because of the low existing market share of gas fired units it was not practical to get a fair equipment and installation cost comparison.

The assumptions used in calculating annual energy costs are provided in Appendix D.

8.1.7 Pavement and Driveway Heating

Table 39 - Impact of Pavement and Driveway Heating Program (PJ/yr)

	Retrofit	New Construction
Lower Mainland	0.1	1.0
Interior	< 0.1	< 0.1
Vancouver Island	< 0.1	< 0.1
Total	0.1	0.1

Retrofit & New Construction

Both of these market segments are relatively similar for the purposes of this opportunity.

The opportunity impact values in the table above are based on converting five percent of the existing Single Family Dwelling market to gas heating for pavement and driveway over a five-year period. It is suggested that an aggressive promotional campaign with a moderate incentive could persuade consumers to purchase gas heaters.

Table 40 - Gas and Electric Pavement and Driveway Heating - Annual Energy Costs

	Pavement/Driveway and Heating	Electric
Lower Mainland	\$638	\$802
Interior	\$1,014	\$1,276
Vancouver Island	\$775	\$802

The assumptions used in calculating annual energy costs are provided in Appendix D.

Table 41 –Gas and Electric Pavement and Driveway Heating - Cost Assumptions

	Comments
Equipment and Installation Costs	The cost of installing hot water piping system is assumed to be similar to the cost of installing electric heat tracing system.
Maintenance Costs	No data was collected on the relative maintenance costs between electric and gas. It is assumed that they would be similar.

8.2 Commercial

8.2.1 District Heating and Cooling Systems – Integrated Complexes

There is a significant opportunity to expand the development of district heating/cooling systems in areas where institutional and commercial properties are in close proximity to one another. An example would be a new commercial development beside an existing hospital complex. The hospital complex already most likely has a district heating and cooling system with a trained operating staff in place. It is suggested that there would be an opportunity for the hospital district system to be expanded to serve the new commercial development. In this situation there would also be an opportunity to employ absorption chillers to serve the chilled water system.

These types of developments would favour the use of natural gas over electricity, because some of the options for new commercial developments are ground source heat pumps, air to air heat pumps or electricity resistance heating in combination with centrifugal chillers. The table below is an estimate of the gas sales impact for this opportunity.

Table 42 - Estimated Impact of District Heating Systems – Integrated Complexes (PJ/yr)

	Retrofit	New Construction
Lower Mainland	-	0.2
Interior	-	0.1
Vancouver Island	-	0.1
Total	-	0.4

Retrofit & New Construction

For the purposes of this discussion, the designation between retrofit and new construction is not clear. In some cases new developments would be targeted that are next to existing district heating systems; in which case the additional gas demand would be due mainly to the requirement of the new development but the existing system would require some retrofit work. In other situations the potential district system would only involve new construction properties.

The realization of this opportunity would require a marketing program which would target specific types of new developments. The impact values above are based on the following assumptions:

- New developments involving large hotels, large offices, retail malls, recreational complexes and educational institutions would be the target facilities; and
- Eight percent of the energy use in these developments with respect to space heating, domestic hot water and space cooling would be changed from electricity to natural gas.

It is estimated that the annual energy costs for these developments which generally would involve purchasing hot and chilled water from a district heating complex would be comparable to the cost of purchasing electricity and gas for use in their own equipment.

From a capital cost consideration, there would be considerable savings to the new development because they would not have to pay for boiler and chiller equipment in their own complex.

8.2.2 Natural Gas Cogeneration in Commercial Institutional Facilities

There is a potential for cogeneration in connection with base loaded water heating. The major barrier to cogeneration has been that the sale of the electricity from a cogeneration facility has been on a long-term fixed price basis whereas it has not been practical to obtain a long term fixed price for the additional gas required. However, due to BC Hydro's need for power it is suggested that it may be possible to obtain a price for the electricity sold to BC Hydro that would be indexed to natural gas prices. The main argument for such a BC Hydro policy is that the electricity produced by a cogeneration facility is generated at a very high rate of efficiency (80% compared to 50% for conventional electricity generation from natural gas).

The opportunity suggested involves base loaded water heating and not space heating. The water heating load is relatively continuous throughout the year and a cogeneration project could be base loaded. One of the keys to this opportunity is the development of micro-cogen equipment (30 kW to 100 kW projects).

Table 43 – Estimated Impact of Commercial Cogeneration Program (PJ/yr)

	Retrofit	New Construction
Lower Mainland	1.2	< 0.1
Interior	0.1	< 0.1
Vancouver Island	< 0.1	< 0.1
Total	1.4	0.1

The above impacts are based on the following assumptions:

- Previous studies done by Willis Energy with respect to cogeneration projects at hospitals, universities and some commercial institutions, mostly universities in the Lower Mainland.
- 25% of the potential water heating systems would be cogeneration projects for the following new types of facilities: Recreation, Food Retail, Large Hotel, Hospital, University/College and Restaurant/Tavern.

An important consideration with this opportunity is the fuel cost of the electricity produced by micro-cogeneration projects. The table below indicates this cost, assuming different gas prices and a plant efficiency of 75%.

Table 44 – Fuel Cost of Electricity from Commercial Natural Gas Project

Natural Gas Cost in \$/GJ	Fuel Cost of Electricity \$/MWh
\$10	\$48.0
\$11	\$52.8
\$12	\$57.6

Besides fuel cost, there is a considerable capital and operating and maintenance cost to these type of projects. The table below provides approximate information on the breakdown between these components and the resulting total cost of electricity generated.

Table 45 –Electricity Generation

	Cost of Electricity Produced from Commercial Cogeneration \$/MWh
Capital Cost	\$39
Operating & Maintenance	\$22
Fuel Cost	\$50
Total	\$111

In considering this cost it is important to consider that most of these projects would be located in the Lower Mainland and would provide transmission and distribution benefits to BC Hydro.

8.2.3 Increase in Market Share for Natural Gas Water Heater – Instantaneous

Instantaneous or tankless water heater systems were identified as an opportunity in the residential sector. There is also an opportunity in the commercial/institutional sector due to a number of applications which require relatively small amounts of hot water, infrequently for short periods of time.

The table below indicates a potential increase in annual natural gas sales for each region if the market share for natural gas water heaters was increased relative to electric water heaters. It is also suggested that an incentive could persuade consumers to select gas water heaters.

Table 46 - Impact of Instantaneous Natural Gas Water Heater Program (PJ/yr)

	Retrofit	New Construction
Lower Mainland	< 0.1	< 0.1
Interior	< 0.1	< 0.1
Vancouver Island	< 0.1	< 0.1
Total	< 0.1	< 0.1

Instantaneous water heaters are new on the market in B.C. and we were not able to obtain data on their uptake within this market. The above impacts are based on the following assumptions:

- For all of the existing building types within the Commercial sector, that two percent of the existing electricity use in water heating could be changed to gas consumption.
- With respect to all new buildings within the Commercial sector, that four percent of the forecast electricity use in water heating could be changed to gas consumption.

The table below provides the annual energy cost difference between conventional electric water heaters and instantaneous gas units. The gas water heaters for all regions have a slightly lower annual energy cost than electric conventional tank water heaters.

Table 47 - Gas and Electric Water Heaters - Annual Energy Costs

	Gas Water Heaters Mid-Efficiency	Electric Mid-Efficiency
Lower Mainland	\$282	\$299
Interior	\$231	\$245
Vancouver Island	\$281	\$245

The assumptions used in calculating annual energy costs are provided in Appendix D.

Table 48 –Gas and Electric Water Heater – Cost Assumptions

	Gas Water Heater	Electric
Initial Cost Comparison	\$670	\$420
Annual Operation and Maintenance	\$150-1,000	\$250-350

Capital and installation costs are provided in Appendix C.

8.2.4 Increase in Market Share for Hot Tubs

In certain sub-segments in the commercial sector there is an opportunity to increase the number of gas fired hot tubs. The hotel and recreation sectors are prime examples.

The table below indicates a potential increase in annual natural gas sales for each region if the market share for hot tubs was increased relative to electric units in the commercial sector.

Table 49 - Impact of Jacuzzi/Hot tub Program Commercial Sector (PJ/yr)

	Retrofit	New Construction
Lower Mainland	0.1	< 0.1
Interior	< 0.1	< 0.1
Vancouver Island	< 0.1	< 0.1
Total	0.1	< 0.1

New Construction

For the impact on new construction, the annual energy costs are provided in the table below:

Table 50 - Gas and Electric Hot Tubs- Annual Energy Costs

	Gas	Electric
Lower Mainland	\$635	\$446
Interior	\$677	\$446
Vancouver Island	\$673	\$446

The assumptions used in calculating annual energy costs are provided in Appendix D.

8.3 Industrial

8.3.1 General Industrial Cogeneration

Besides the greenhouse industry, there are a number of other opportunities for industrial cogeneration using natural gas. As with commercial and greenhouse cogeneration opportunities, the major barrier is the gas price risk.

The table below indicates the impact on gas sales if approximately five percent of the existing process steam loads in the Pulp & Paper, Wood Products, Chemical, Mining & Manufacturing industrial sub-sectors could be converted from conventional boilers to gas turbines and heat recovery steam generator projects.

Table 51 - Estimated Impact of Cogeneration (PJ/yr)

	Retrofit	New Construction
Lower Mainland	0.6	-
Interior	1.0	-
Vancouver Island	0.6	-
Total	2.2	-

The table below indicates the fuel cost component of the electricity that would be generated by these types of facilities.

Table 52 – Fuel Cost of Electricity from General Industrial Natural Gas Projects

Natural Gas Cost in \$/GJ	Fuel Cost of Electricity \$/MWh
\$8	\$38
\$9	\$43
\$10	\$48

The table below provides a rough estimate of the total cost of electricity from these types of projects.

Table 53 –Electricity Generation

	Cost of Electricity Produced from Commercial Cogeneration \$/MWh
Capital Cost	\$27
Operating & Maintenance	\$20
Fuel Cost	\$43
Total	\$90

In considering this cost it is important to consider that a significant portion of these projects would be located in the Lower Mainland and would provide transmission and distribution benefits to BC Hydro.

8.3.2 Greenhouse Cogeneration

The greenhouse industry in particular in the Lower Mainland has been interest in Cogeneration for a number of years. One of the main reasons for their interest is the large use of cogeneration by the greenhouse industry in the Netherlands. Greenhouse cogeneration is extremely efficient because of the use of high efficiency heat exchangers and because the CO₂ in the exhaust gas can be used to stimulate plant growth. In fact, greenhouses burn natural gas specifically just to produce CO₂.

The major barrier to this type of cogeneration, is that a long-term contract for the sale of electricity is based on a fixed price whereas it is not practical to purchase natural gas at a fixed price on a similar type of long-term contract. Accordingly, a cogeneration project would require a greenhouse owner to take the long-term gas price risk escalation.

Willis Energy has worked with the Greenhouse industry on a number of occasions and the impact table below is based on that work.

Table 54 - Estimated Impact of Greenhouse Cogeneration (PJ/yr)

	Additional Gas Sales for Greenhouse Cogeneration PJ/yr
Lower Mainland Greenhouses	2.0

A key aspect of this opportunity is the fuel cost component of the electricity that would be generated by these types of facilities. The table below indicates this fuel cost component for different natural gas prices.

Table 55 – Fuel Cost of Electricity from Commercial Natural Gas Project

Natural Gas Cost in \$/GJ	Fuel Cost of Electricity \$/MWh
\$8	\$26.2
\$9	\$29.5
\$10	\$32.7

The table below provides a rough estimate of the total cost of electricity from these types of projects.

Table 56 –Electricity Generation

	Cost of Electricity Produced from Commercial Cogeneration \$/MWh
Capital Cost	\$33
Operating & Maintenance	\$25
Fuel Cost	\$30
Total	\$88

In considering this cost it is important to consider that all of these projects would be located in the Lower Mainland and would provide transmission and distribution benefits to BC Hydro.

8.3.3 Infra-Red

For many industrial applications, radiant heating is the most effective and efficient heating for human comfort. There are situations where it is not practical to enclose the workplace but a radiant heater can direct heat onto individuals in the space. Electric radiant heating is often the type of equipment selected. However, it is suggested that the market share of gas-fired units could be increased with a promotional effort.

It was not practical to properly estimate the market for this opportunity. However, Willis's experience has indicated that in very rough terms about two percent of industrial steam load is used for space heating where gas fired radiant heating would be applicable. The table below indicates the impact on gas sales if half of this load or 1% of the process load was converted to gas fired radiant heat.

Table 57 - Impact of Infra-Red Heating (PJ/yr)

	Retrofit	New Construction
Lower Mainland	<.1	-
Interior	0.1	-
Vancouver Island	<.1	-
Total	0.2	-

The table below indicates an approximate economic comparison between gas and electric infrared heat.

Table 58 –Gas and Electric Infra-Red Heating – Economic Comparison

	Comments
Initial Cost Comparison	The capital cost comparison is dependent on the availability of gas throughout a site but in general it is estimated that gas-fired infrared will be 50% more expensive.
Energy Costs	Gas and electricity costs vary depending on the size of the industrial site. At \$8.00 per GJ, Gas Infrared would cost the equivalent of 3.2 cents/kWh, which is about 15% less than BC Hydro's transmission electricity rate and 35% less than BC Hydro's industrial distribution rate.
Annual Operation and Maintenance	It is estimated that the annual operating and maintenance costs would be similar.

9 THREATS ANALYSIS

There is a significant threat to natural gas sales in British Columbia due to an electricity pricing advantage. The prices that BC consumers pay for electricity is based mainly on the cost of “Heritage” power while the price of natural gas is mainly due to a value for gas based on a North American market derived value. “Heritage” power is the electricity generated by hydroelectric projects that were built 25 to 70 years ago. This discrepancy between the cost of “Heritage” power and the current market price for energy was not a major factor until recently.

For approximately 15 years from 1985 to 2000 the price of electricity was relatively stable at six cents/kWh for residential customers and the price of natural gas was about four dollars per GJ. The market share for electricity and natural gas in the British Columbia market developed over this time period, based on these base price levels. Electricity and natural gas as energy forms have relative advantages and disadvantages over each other; however, a key advantage to natural gas over this period was price. On a direct energy comparison four dollars per GJ is equal to 1.4 cents/kWh so that even though electric appliances, furnaces and boilers may be more efficient than their gas counterparts, for many energy applications such as space heating, natural gas dominated the market because of price.

Currently however, the price of electricity for residential customers has only gone up slightly to 6.2 cents/kWh, or \$17.43/GJ, but natural gas at the retail level is 4.5 cents/kWh or \$12.50/GJ. Taking efficiency into consideration, and the differences in capital costs, natural gas is no longer the obvious low-cost alternative.

In analyzing threats the following was taken into consideration:

- Size of target market (for example space heating and domestic hot water are the two largest market segments in terms of energy sold)
- Market evidence that natural gas advantages have been promoted and accepted by customer groups (for example, it is known that heat pump supplier and contractors are very busy at the present time).
- Equipment and installation cost (for example, air to air heat pumps are relatively inexpensive) compared to gas furnace and central electric air conditioning systems.
- Market inertia and distribution infrastructure (how easily can sales of a particular piece of equipment be increased in terms of sales and delivery effort).

Market and cost information for the list of Threats was obtained primarily through site visits to new developments in the Lower Mainland; interviews with developers, HVAC contractors, retail customer service representatives and Terasen Gas staff.

9.1 Residential

9.1.1 *Increase in Market Share Air to Air Heat Pumps*

The table below indicates a potential decrease in annual natural gas sales for each region if the market share for air to air heat pumps was decreased.

Table 59 - Impact of Air to Air Heat Pump Program (PJ/yr)

	Retrofit	New Construction
Lower Mainland	3.1	1.2
Interior	0.9	0.2
Vancouver Island	0.6	0.4
Total	4.6	1.8

Retrofit

For the Retrofit values the impact values are based on 5% of all the housing types except for high-rises being converted from gas heating to air to air heat pumps over the next five years. This seems like a high number, however air to air heat pumps do provide an air conditioning benefit and there is not a penalty with respect to annual energy costs.

Natural Resources Canada data indicated that the heat pump share of the space heating market grew from 1.7% in 1997 to 2.6% in 2004 and the market activity of heat pump suppliers appears to have dramatically increased recently. Accordingly, a 5% increase in the retrofit market over the next 10 years appears reasonable. However, the 5% value is not based on a market analysis.

New Construction

For new Single Family Homes, air to air heat pumps will be an easier sell.

The opportunity impact values in the table above are based on the market share for air to air heat pumps being increased by 10% over the existing forecast values.

In comparing the overall economics of an air to air heat pump to a gas furnace with air conditioning, it is important to consider a number of factors such as:

- The type and efficiency of the heat pump.
- The type and efficiency of the furnace and air conditioning unit.
- Specific gas and electricity rates

The table below compares the annual energy costs of an air-to-air heat pump with a gas furnace.

Table 60 - Air-to-Air Heat Pump vs. Gas Furnace

	Air to Air Heat Pump	High Efficiency Gas Furnace
Lower Mainland	\$275	\$783
Interior	\$275	\$651
Vancouver Island	\$334	\$647

The assumptions used in calculating annual energy costs are provided in Appendix D.

In comparing the equipment and installation costs of air to air heat pumps with high efficiency gas furnaces it is necessary to also consider the cost of conventional air conditioning. The table below is an estimate of the capital costs of the two alternatives.

Table 61 - Equipment and Installation Cost Comparison: Air-to-Air Heat Pumps

Air to Air Heat Pump	High Efficiency Gas Furnace with Air Conditioning
\$6,000	\$4,000

9.1.2 Reduction in Market Share Residential Water Heaters

The table below indicates a potential decrease in annual natural gas sales for each region if the market share for water heaters was decreased relative to electric water heaters.

Table 62 - Impact of Reduced Natural Gas Water Heaters (PJ/yr)

	Retrofit	New Construction
Lower Mainland	1.7	1.7
Interior	0.8	0.5
Vancouver Island	0.6	0.4
Total	3.0	2.5

Retrofit & New Construction

Terasen Gas' account manager noted that new regulations concerning gas condensing furnace efficiency will come into effect in 2008. The impact on gas water heaters is due to the increased costs of venting requirements. It is anticipated that developers will opt for electrical space heating, given the new the efficiency standard for gas furnaces. As such, venting would only be required for water heating purposes. Notes from the field in Vancouver Island, already show that customers undertake costly ventilation when space and water heating can be combined. Should ventilation be required solely for the purposes of water heating, it is expected that both customers and developers will choose electrical water heating.

A very aggressive program should be developed to retain this market. Benefits of using gas as the fuel of choice for water heating should be promoted heavily (i.e. better ability to meet capacity).

Table 63 - Gas and Electric Water Heater - Annual Energy Costs

	Gas Water Heater (Mid Efficiency)	Electric
Lower Mainland	\$282	\$299
Interior	\$231	\$245
Vancouver Island	\$281	\$245

Capital and installation costs are provided in Appendix C. The assumptions used in calculating annual energy costs are provided in Appendix D.

9.1.3 Increase in Electric Space Heating Market Share – Due to Improved Controls

This threat is based on the potential for developers to use improved control techniques for new construction and build all-electric homes. The impact values in the table below are based on the electric heating share for single family homes being increased by 20% over forecast values.

Table 64 - Impact of Improved Controls (PJ/yr)

	Retrofit	New Construction
Lower Mainland	-	1.9
Interior	-	0.4
Vancouver Island	-	0.6
Total	-	2.9

Retrofit & New Construction

For the purposes of this study, the impact of retrofits was considered negligible. The major potential lies with the new construction market.

In this comparison of electric heat to gas heat, it is assumed that there is no capital cost difference. Conventional electric base board is considerably less expensive than a hot air furnace. However, in the improved control situation it is assumed that the improved control scenario consists of a combination of radiant floors, baseboards and electric hot air furnaces combined with computer control.

9.1.4 Reduction in Market Share Residential Space Heating – Gas to Wood Pellets (Interior)

The table below indicates a potential increase in annual natural gas sales for each region if the market share for natural gas dryers was increased relative to electric dryers.

Table 65 - Impact of Wood Pellets Heating (PJ/yr)

	Retrofit	New Construction
Lower Mainland	0.2	0.1
Interior	0.1	< 0.1
Vancouver Island	0.1	< 0.1
Total	0.4	0.2

Retrofit & New Construction

Interview with the Wood Pellet Association of Canada noted that data on total percentage of residences in BC using wood pellet stoves was not available. It is still a fuel that is used primarily for commercial operations. In BC, residential use is strongest in the Interior and northern regions especially in proximity to woodwaste availability. Their main benefit is cost effectiveness and price stability.

Fuel for the stoves is produced from dried, finely ground wood waste that is compressed into hard pellets about the diameter of a pencil and up to 2 cm (1 in.) in length. Once a 18.1-kg (40-lb.) bag of pellets is loaded into its hopper, a stove can run automatically for up to 24 hours as the pellets are metered gradually into a small combustion chamber.

Table 66 - Wood Pellets and Electric Stoves - Annual Energy Costs

	Wood Pellets	Gas Furnace High-Efficiency
Lower Mainland	\$808	\$783
Interior	\$672	\$942
Vancouver Island	\$550	\$647

9.1.5 Reduction in Market Share for Gas Fireplaces versus Electric Fireplaces

The table below indicates a potential decrease in annual natural gas sales for each region if the market share for natural gas fireplaces was decreased relative to electric fireplaces.

Table 67 - Impact of Gas Fireplaces Program (PJ/yr)

	Retrofit	New Construction
Lower Mainland	-	0.2
Interior	-	< 0.1
Vancouver Island	-	< 0.1
Total	-	0.3

Retrofit & New Construction

For the purposes of this discussion, we have assumed that retrofit opportunities are non-existent. Site visits and interviews revealed retrofits are very unlikely once the fireplace has been installed. Although natural gas fireplaces make up the majority of fireplaces currently installed in low-rise and high-rise apartments buildings (60% of residences in BC), the popularity of electric fireplaces is increasing.

Electric fireplaces are easier to install as they are generally freestanding, portable units. They simply need to be plugged into a conventional outlet and there is no need for additional piping or venting. Electric fireplaces are gaining popularity in condominiums or apartments that don't have access to gas lines, or have limited renovation capability. It is suggested that this threat is not significant for the SFD market. The threat impact values are based on the number of gas fireplace installations in new construction for other housing types being reduced by 50% from the projected values

The value of 50% appears high, however in surveying new high-rise buildings being marketed, it was noted that a number of them either do not have fireplaces or they are electric, examples are the Donovan and the Shangri-la in downtown Vancouver and the Pier in North Vancouver. The 50% is not based on an extensive market analysis but a preliminary survey of the market.

Annual energy costs between gas and electric fireplaces are not an important consideration with respect to market share. However, an estimate of the comparable annual costs is provided below.

Table 68 – Gas and Electric Fireplaces - Annual Energy Costs

	Gas Fireplaces	Electric
Lower Mainland	\$163	\$77
Interior	\$166	\$78
Vancouver Island	\$198	\$77

The assumptions used in calculating annual energy costs are provided in Appendix D.

9.1.6 Increase in Geothermal Space Heating Market Share

The table below indicates a potential decrease in annual natural gas sales for each region if the market share for geothermal space heating was increased by five percent for single family dwellings and high-rise MURBs with respect to new construction. Geothermal is not considered competitive in the retrofit market although there have been some conversions such as the Mole Hill project in Vancouver.

New Construction

For the luxury market, especially large single family dwelling and high-rise MURBs, installation of geothermal systems can be used as an added selling feature. According to an interview conducted with Terasen Gas customer representatives, this opportunity is not considered a very large threat. Any incentives should be targeted to the developer who would incur additional engineering costs at the project planning stage

Table 69 - Impact of Increase Geothermal Space Heating (PJ/yr)

	Retrofit	New Construction
Lower Mainland	-	0.4
Interior	-	0.1
Vancouver Island	-	0.1
Total	-	0.6

Table 70 - Geothermal and Natural Gas Space Heating - Annual Energy Costs

	Geothermal	Natural Gas High-Efficiency
Lower Mainland	\$207	\$783
Interior	\$207	\$651
Vancouver Island	\$252	\$647

9.2 Commercial

9.2.1 Air to Air Heat Pumps

In the Commercial sub-sectors where small to medium size buildings dominate, air-to-air heat pumps will replace at least a small percentage of the gas fired roof-top units or small gas fired boilers. The table below is an estimate of the impact.

Table 71 - Estimated Impact of Air-to-Air Heat Pumps (PJ/yr)

	Retrofit	New Construction
Lower Mainland	0.8	0.2
Interior	0.5	0.1
Vancouver Island	0.1	< 0.1
Total	1.4	0.3

Retrofit

Customers will probably not remove the existing gas units but will add an air to air heat pump which will provide some air conditioning as well as provide some space heating in the shoulder season.

The impact values in the table above are based on a five percent loss of gas load in the following commercial sub-sectors:

- Small Commercial
- Medium Office
- Medium Hotel/Motel
- Nursing Homes
- Restaurant/Tavern
- Mixed Use

New Construction

For new construction it is expected that the air to air heat pumps will make a more significant penetration because developers of new projects will be attracted to the heat pump option because it can provide air conditioning. In some of the small/medium sized buildings heat pumps in combination with electric resistance heating could provide all of the heating energy required. The impact values in the table above are based on the same sub-sectors but a 10% reduction in the forecast gas load for this sector.

The capital cost comparison will be similar to the comparison in the residential situation.

9.2.2 Electric Control

The table below indicates a potential decrease in annual natural gas sales for each region if the market share for natural gas space heating was decreased compared to electric space heating.

Table 72 - Impact of Electric Control (PJ/yr)

	Retrofit	New Construction
Lower Mainland	-	0.7
Interior	-	0.3
Vancouver Island	-	0.1
Total		1.0

Retrofit

No impact is assumed in the retrofit market.

New Construction

The impact table above is based on a 30% decrease in natural gas space heating, with respect to new construction in the following sub-sectors:

- Small Commercial
- Recreation Facilities
- Large Office
- Medium Office
- Large Non-Food Retail
- Medium Non-Food Retail
- Food Retail
- Large Hotel
- Medium Hotel/Motel
- Warehouse/Wholesale
- Mixed Use

For the new construction market the estimated impact is due to more developers and HVAC engineers deciding that the design of an all electric heating system is less expensive. Through improved controls and building management systems, the cost difference between electricity and natural gas would be minimized.

On an annual energy cost basis the electricity option is expected to be in the order of only 10% more expensive. However, from a capital cost perspective the gas alternative is expected to be \$4.00 to \$6.00 more expensive per square foot of building space.

9.2.3 Geo-Exchange in Large Commercial Buildings

As with large residential strata-title buildings, geo-exchange is continually becoming more popular in the commercial sector. Over the last six months, hotels, institutions and large commercial parks have indicated their intention to install geo-exchange systems. The table below is an estimate of the impact in reduced natural gas sales.

Table 73 – Estimated Impact of Geo-Exchange Large Commercial Buildings (PJ/yr)

	Retrofit	New Construction
Lower Mainland	-	0.1
Interior	-	< 0.1
Vancouver Island	-	< 0.1
Total		0.2

Retrofit

For the purposes of this study, retrofitting existing buildings for geo-exchange systems was not considered practical.

New Construction

The impact values above are based on a 20% increase in geo-exchange systems and a 20% decrease in natural gas space heating systems. The sub-sectors that were assumed to be affected were:

- Recreation Facilities
- Large Office
- Large Hotel
- Hospital
- Mixed Use

The impact values may appear relatively small considering the 20% change in buildings. However, it is important to note that space heating does not make up the same percentage of energy use in commercial buildings as in residential units. For example, lighting and plug loads actually provide most of the space heating load in commercial buildings. Accordingly, a change from gas to geo-exchange is not as big an impact as would be expected.

With respect to economics, geo-exchange proponents are indicating a significant savings in energy costs. Willis has not reviewed these comparisons in detail and is not confident enough to indicate a fair comparison. One of the concerns is that if geo-exchange systems are undersized, a significant portion of the space heating will actually revert back to electric resistance heating.

Capital cost comparisons of geo-exchange systems relative to natural gas hydronic and all electric are very site dependent. The following table is a rough estimate developed by Willis Energy.

Table 74 – Large Commercial Building Heating System Capital Cost Comparison

Cost Item	Electric	Natural Gas	GSHP
Major Mechanical Cost	161%	152%	100%
Distribution System Cost	63%	119%	100%
Ground Loop Cost	0%	0%	100%
Total Cost	84%	92%	100%

9.3 Industrial

9.3.1 *Wood Waste Boilers*

Most pulp and paper mills utilize power boilers to produce steam for electricity and process steam production. The fuel for these units is a combination of wood waste and natural gas. The percentage of natural gas ranges from 10% to 40%. The ones that use a higher percentage of natural gas usually do so for control reasons. The process steam requirement in most mills fluctuates from hour to hour and it is easier to control a boiler by varying gas use versus wood waste. Therefore the boiler operators tend to prefer to operate with a high gas consumption level so that they can easily turn the boiler up or down.

However, due to the increase in gas prices, mills are employing more sophisticated control measures in order to reduce the gas percentage. Some mills have succeeded in significantly reducing their use. The table below indicates the impact on reduced gas sales based on a five percent reduction in the natural gas used in existing pulp mill power boilers.

Table 75 - Estimated Impact of Wood Waste Boilers (PJ/yr)

	Retrofit	New Construction
Lower Mainland	2.5	-
Interior	4.4	-
Vancouver Island	2.6	-
Total	9.4	-

The capital cost of improving boiler control is not available. It is estimated that the annual fuel cost savings between natural gas and wood waste is approximately \$6.00 per GJ.

9.3.2 *Lime Kiln Alternatives*

All the kraft pulp mills in BC have lime kilns as part of their process. Each kiln uses 1,000 to 2,000 GJ of natural gas per day. A number of the mills are investigating fuel alternatives to natural gas including petroleum coke and gasified wood waste. It should be noted that it is estimated that many of the gas fired kilns are operating at an efficiency level considerably below optimum.

The table below indicates the impact if two of these kilns are converted from natural gas to an alternative fuel over the next five years.

Table 76 - Reduced Natural Gas Sales Due to Conversion of Lime Kilns

	Annual Reduction in Gas Sales PJ/yr
All of BC	1.0 PJ/yr

The capital cost of converting kiln to an alternate fuel is not available. It is estimated that the annual fuel cost savings in a conversion is \$5.00 per GJ resulting in an annual savings per kiln of \$2,600,000.

9.3.3 Wood-Waste Kilns

Most sawmill and other wood product plants dry their finished product. Natural gas is the dominant fuel that is used in this drying process. However, there is a strong interest in a variety of wood waste fired equipment. The most common are thermal energy systems that burn wood waste in a combustion chamber and distribute the heat generated to the dry kilns by means of a hot oil piping network. Wood waste gasifiers are another technology as well as wood waste fired cogeneration plants.

The table below indicates the impact if 20% of the existing dry kilns in the wood products sector were converted from natural gas to wood waste.

Table 77 - Impact of Wood Waste Kilns (PJ/yr)

	Retrofit	New Construction
Lower Mainland	< 0.1	-
Interior	0.2	-
Vancouver Island	< 0.1	-
Total	0.3	-

Assuming \$8.00 per GJ as the natural price, the payback in converting a gas kiln to a wood waste unit is approximately four years. One item that mills may miss in this economic comparison is the increased maintenance costs for wood waste units.

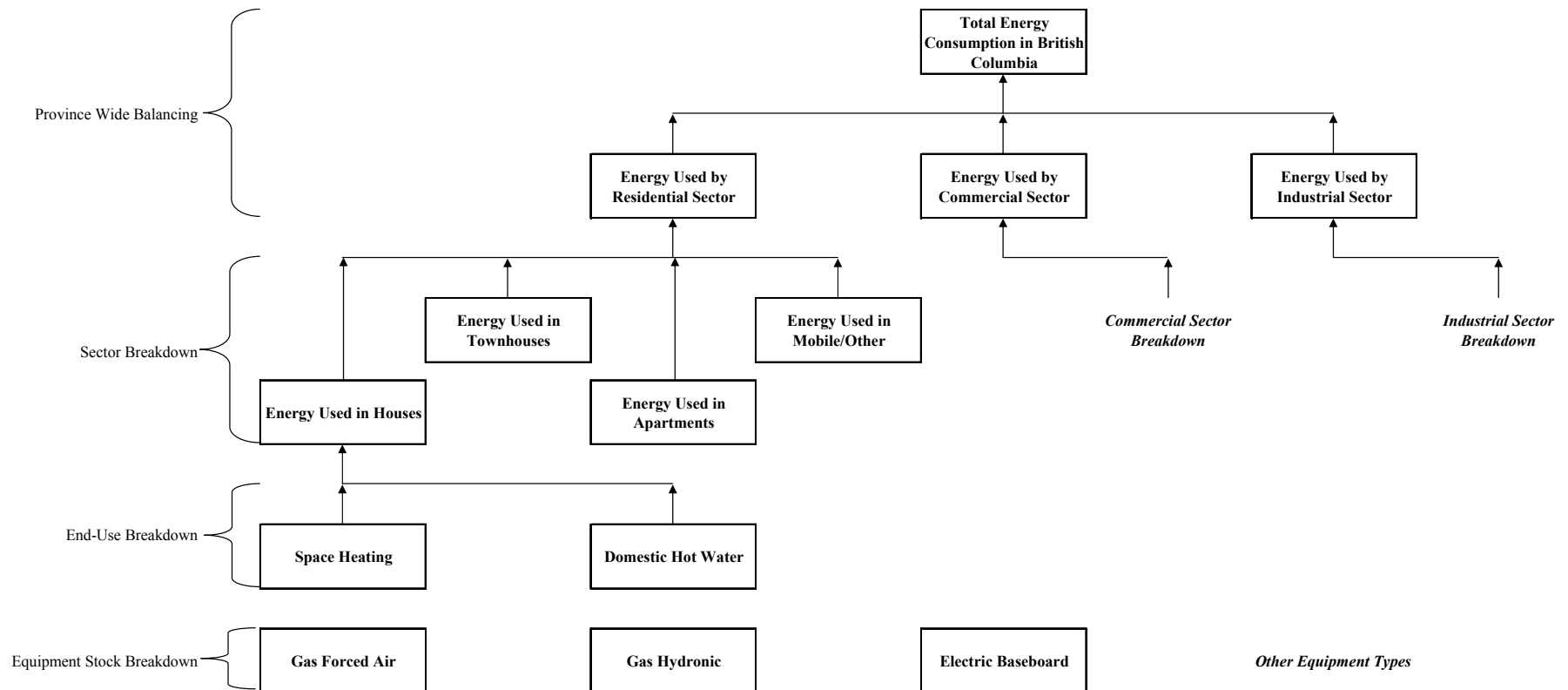
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APPENDIX A – MODEL EXPLANATION AND HIERARCHY

The retrofit market and the new construction market will be treated separately.

Retrofit Model



New Construction Market

Similar type of model as retrofit model except the total market will be treated as the total buildings or facilities that will be constructed over the next ten years.

APPENDIX B – REGIONAL ENERGY USE BREAKDOWN

Lower Mainland - Sector Energy Use Breakdown TJ/yr

Sector	All Fuel Sources (TJ)		Electricity (TJ)		Natural Gas* (TJ)		Wood (TJ)		Oil/Propane (TJ)		Other (TJ)	
Residential	224,130	61%	40,211	41%	122,760	70%	46,021	62%	5,569	70%	9,568	70%
Commercial/Institutional	88,351	24%	32,365	33%	33,321	19%	18,557	25%	1,512	19%	2,597	19%
Industrial	56,819	15%	25,500	26%	19,291	11%	9,650	13%	875	11%	1,503	11%
Total	369,300		98,076		175,372		74,228		7,956		13,668	

Vancouver Island - Sector Energy Use Breakdown TJ/yr

Sector	All Fuel Sources (TJ)		Electricity (TJ)		Natural Gas* (TJ)		Wood (TJ)		Oil/Propane (TJ)		Other (TJ)	
Residential	46,160	39%	20,618	37%	8,846	49%	15,605	37%	401	49%	689	49%
Commercial/Institutional	24,992	21%	8,916	16%	8,304	46%	6,748	16%	377	46%	647	46%
Industrial	47,027	40%	26,191	47%	903	5%	19,822	47%	41	5%	70	5%
Total	118,179		55,725		18,053		42,175		819		1,407	

Interior - Sector Energy Use Breakdown TJ/yr

Sector	All Fuel Sources (TJ)		Electricity (TJ)		Natural Gas* (TJ)		Wood (TJ)		Oil/Propane (TJ)		Other (TJ)	
Residential	71,024	36%	15,692	22%	38,685	60%	11,876	22%	1,755	60%	3,015	60%
Commercial/Institutional	29,522	15%	8,559	12%	12,895	20%	6,478	12%	585	20%	1,005	20%
Industrial	97,191	49%	47,076	66%	12,895	20%	35,629	66%	585	20%	1,005	20%
Total	197,737		71,328		64,475		53,984		2,925		5,025	

Lower Mainland - Residential Building Type Breakdown TJ/yr

Residential Building Type	All Fuel Sources (TJ)		Electricity* (TJ)		Natural Gas ** (TJ)		Wood*** (TJ)		Oil† (TJ)		Other*** (TJ)
SFD/Duplex	117,044	68%	25,227	63%	82,249	67%		63%		67%	9,568
Row/Townhouses	11,077	6%	3,711	9%	7,366	6%	-	9%		6%	-
Low Rise	25,646	15%	6,005	15%	19,642	16%	-	15%		16%	-
High Rise	13,943	8%	3,632	9%	10,312	8%	-	9%		8%	-
Mobile/Other	4,583	3%	1,637	4%	2,946	2%	-	4%		2%	-
Total	172,294		40,211		122,760		46,021		5,569		9,568

Vancouver Island - Residential Building Type Breakdown TJ/yr

Residential Building Type	All Fuel Sources (TJ)		Electricity* (TJ)		Natural Gas ** (TJ)		Wood*** (TJ)		Oil† (TJ)		Other*** (TJ)
SFD/Duplex	34,345	74%	15,667	76%	5,862	66%	11,858	76%	269	67%	689
Row/Townhouses	1,830	4%	835	4%	339	4%	632	4%	24	6%	-
Low Rise	5,203	11%	1,973	10%	1,672	19%	1,494	10%	64	16%	-
High Rise	1,675	4%	671	3%	464	5%	508	3%	32	8%	-
Mobile/Other	3,103	7%	1,471	7%	510	6%	1,114	7%	8	2%	-
Total	46,156		20,618		8,846		15,605		401		689

Interior - Residential Building Type Breakdown TJ/yr

Residential Building Type	All Fuel Sources (TJ)		Electricity* (TJ)		Natural Gas ** (TJ)		Wood*** (TJ)		Oil† (TJ)		Other*** (TJ)
SFD/Duplex	40,076	70%	11,142	71%	25,919	70%		71%		70%	3,015
Row/Townhouses	2,709	5%	388	2%	2,321	2%	-	2%		2%	-
Low Rise	7,355	13%	1,165	7%	6,190	11%	-	7%		11%	-
High Rise	3,678	6%	429	3%	3,250	3%	-	3%		3%	-
Mobile/Other	3,496	6%	2,567	16%	928	14%	-	16%		14%	-
Total	57,315		15,692		38,685		11,876		1,755		3,015

Lower Mainland - Commercial/Institutional Building Type Breakdown (Annual Energy Used in Year 2004 in TJ)

Sub Sector	All Fuel Sources (TJ)		Electricity* (TJ)		Natural Gas** (GJ)		Wood (TJ)		Oil*** (TJ)		Other*** (TJ)	
Small Commercial	29,753	43%	13,284	41%	14,661	44%	-	41%	665	44%	1,143	44%
Recreation Facilities and Other	2,994	4%	-	0%	2,666	8%	-	0%	121	8%	208	8%
Miscellaneous	749	1%	-	0%	666	2%	-	0%	30	2%	52	2%
Large Office	6,562	9%	5,439	17%	1,000	3%	-	17%	45	3%	78	3%
Medium Office	1,829	3%	1,080	3%	666	2%	-	3%	30	2%	52	2%
Large Non-Food Retail	4,260	6%	3,137	10%	1,000	3%	-	10%	45	3%	78	3%
Medium Non-Food Retail	1,549	2%	800	2%	666	2%	-	2%	30	2%	52	2%
Food Retail	1,361	2%	987	3%	333	1%	-	3%	15	1%	26	1%
Large Hotel	1,495	2%	746	2%	666	2%	-	2%	30	2%	52	2%
Medium Hotel/Motel	688	1%	314	1%	333	1%	-	1%	15	1%	26	1%
Hospital	4,218	6%	849	3%	2,999	9%	-	3%	136	9%	234	9%
Nursing Homes	866	1%	118	0%	666	2%	-	0%	30	2%	52	2%
Large School	2,445	4%	947	3%	1,333	4%	-	3%	60	4%	104	4%
Medium School	1,885	3%	388	1%	1,333	4%	-	1%	60	4%	104	4%
University/College	4,343	6%	1,723	5%	2,332	7%	-	5%	106	7%	182	7%
Restaurant/Tavern	2,119	3%	997	3%	1,000	3%	-	3%	45	3%	78	3%
Warehouse/Wholesale	2,213	3%	1,389	4%	733	2%	-	4%	33	2%	57	2%
Mixed Use	317	0%	167	1%	133	0%	-	1%	6	0%	10	0%
Total	69,646		32,365	100.00%	33,321	100%	n/a	n/a	1,512	100%	2,597	100%

Vancouver Island - Commercial/Institutional Building Type Breakdown (Annual Energy Used in Year 2004 in TJ)

Building Segment	All Fuel Sources (TJ)		Electricity* (TJ)		Natural Gas** (GJ)		Wood (TJ)		Oil*** (TJ)		Other*** (TJ)	
Small Commercial	7,764	43%	3,659	41%	3,654	44%	-	41%	166	44%	285	44%
Recreation Facilities and Other	746	4%	-	0%	664	8%	-	0%	30	8%	52	8%
Miscellaneous	187	1%	-	0%	166	2%	-	0%	8	2%	13	2%
Large Office	1,778	10%	1,498	17%	249	3%	-	17%	11	3%	19	3%
Medium Office	484	3%	298	3%	166	2%	-	3%	8	2%	13	2%
Large Non-Food Retail	1,144	6%	864	10%	249	3%	-	10%	11	3%	19	3%
Medium Non-Food Retail	407	2%	220	2%	166	2%	-	2%	8	2%	13	2%
Food Retail	365	2%	272	3%	83	1%	-	3%	4	1%	6	1%
Large Hotel	392	2%	206	2%	166	2%	-	2%	8	2%	13	2%
Medium Hotel/Motel	180	1%	87	1%	83	1%	-	1%	4	1%	6	1%
Hospital	1,074	6%	234	3%	747	9%	-	3%	34	9%	58	9%
Nursing Homes	219	1%	32	0%	166	2%	-	0%	8	2%	13	2%
Large School	634	3%	261	3%	332	4%	-	3%	15	4%	26	4%
Medium School	480	3%	107	1%	332	4%	-	1%	15	4%	26	4%
University/College	1,128	6%	475	5%	581	7%	-	5%	26	7%	45	7%
Restaurant/Tavern	554	3%	275	3%	249	3%	-	3%	11	3%	19	3%
Warehouse/Wholesale	588	3%	383	4%	183	2%	-	4%	8	2%	14	2%
Mixed Use	83	0%	46	1%	33	0%	-	1%	2	0%	3	0%
Total	18,208		8,916	100%	8,304	100%	n/a	n/a	377	100%	647	100%

Interior - Commercial/Institutional Building Type Breakdown (Annual Energy Used in Year 2004 in TJ)

Sub Sector	All Fuel Sources (TJ)		Electricity* (TJ)		Natural Gas** (GJ)		Wood (TJ)		Oil*** (TJ)		Other*** (TJ)	
Small Commercial	13,405	58%	5,656	66%	6,898	53%	-	66%	313	53%	538	53%
Recreation Facilities and Other	1,025	4%	-	0%	913	7%	-	0%	41	7%	71	7%
Miscellaneous	1,152	5%	-	0%	1,025	8%	-	0%	47	8%	80	8%
Large Office	320	1%	171	2%	133	1%	-	2%	6	1%	10	1%
Medium Office	338	1%	185	2%	136	1%	-	2%	6	1%	11	1%
Large Non-Food Retail	1,021	4%	585	7%	389	3%	-	7%	18	3%	30	3%
Medium Non-Food Retail	393	2%	219	3%	155	1%	-	3%	7	1%	12	1%
Food Retail	530	2%	370	4%	142	1%	-	4%	6	1%	11	1%
Large Hotel	160	1%	117	1%	38	0%	-	1%	2	0%	3	0%
Medium Hotel/Motel	319	1%	117	1%	180	1%	-	1%	8	1%	14	1%
Hospital	614	3%	117	1%	442	3%	-	1%	20	3%	34	3%
Nursing Homes	134	1%	44	1%	80	1%	-	1%	4	1%	6	1%
Large School	1,215	5%	346	4%	773	6%	-	4%	35	6%	60	6%
Medium School	1,077	5%	224	3%	759	6%	-	3%	34	6%	59	6%
University/College	555	2%	136	2%	373	3%	-	2%	17	3%	29	3%
Restaurant/Tavern	530	2%	195	2%	299	2%	-	2%	14	2%	23	2%
Warehouse/Wholesale	211	1%	73	1%	123	1%	-	1%	6	1%	10	1%
Mixed Use	46	0%	5	0%	37	0%	-	0%	2	0%	3	0%
Total	23,045		8,559	100.00%	12,895	100%	n/a	n/a	585	100%	1,005	100%

APPENDIX C – OPPORTUNITIES & THREATS COST ASSUMPTIONS

Water Heaters

Table 78 Gas Water Heater Costs

	Cost	Comment	Sources
Initial Retail Cost	\$670	Kenmore Power Miser 9 50 (U.S.)/42 (Imp.) Gallon 42,500 Btu/hr Mid Efficiency	Survey of major home appliance stores and floor model available at Sears, downtown Vancouver location. Visited March 2007
Installation Costs	\$150-1000	Costs vary depending on size of new tank (in case of tank replacement) and upcoming venting requirements	Oral interview while visiting Sears retail store, downtown Vancouver Location. Visited March 2007.
Annual Operation and Maintenance	-	Not Applicable	Not Applicable

Table 79 – Electric Water Heater Costs

	Cost	Comment	Source
Initial Retail Cost	\$420	Kenmore Power Miser 9 42.1 (Imp.) Gallon 3800 or 5500 W Mid Efficiency	Survey of major home appliance stores and floor model available at Sears, downtown Vancouver location. Visited March 2007
Installation Costs	\$250-350	Costs vary depending on size of new tank (in case of tank replacement)	Oral interview while visiting Sears retail store, downtown Vancouver Location. Visited March 2007.
Annual Operation and Maintenance	-	Not Applicable	Not Applicable

Table 80 –Gas and Electric Water Heater – Cost Assumptions

	Other Assumptions
Initial Cost Comparison	The equipment cost of gas and electric water heaters is approximately the same with prices ranging between \$400 to \$600 depending on the model and the distributor.
Installation Costs	The installation cost difference for new construction is not significant if B Vents can be used (\$150 per house). However, with the requirement for high efficiency furnaces direct venting will be required and it is estimated that the difference will be \$500 to \$1,000. In the case of retrofits, if B – venting is possible the installation difference will be approximately \$500. If B – venting is not possible, the difference will be in the order of \$1,000.
Annual Operation and Maintenance	It is assumed that the operating and maintenance costs for gas and electric will be similar.

Water Heater – Instantaneous

Table 81 - Natural Gas Instantaneous Water Heater Cost

	Cost	Comment	Sources
Initial Retail Cost	\$950	Bosch AquaStar Tankless Water Heater 1600H LP	Floor model available at Home Depot, North Vancouver location. Visited March 2007
Installation Costs	\$100-200	Cost assumes building can meet venting requirements	Oral interview while visiting Home Depot retail store, North Vancouver Location. Visited March 2007.
Annual Operation and Maintenance	\$50-100	Manufacturers' recommendations vary. It should be noted that average tankless water heaters have a life expectancy of 20 years	Oral interview while visiting Home Depot retail store, North Vancouver Location. Visited March 2007.

Table 82 –Electric Instantaneous Water Heater – Cost Assumptions

	Cost	Comment	Sources
Initial Retail Cost	\$700-1300	Bosch Aquastar, American Tankless Water Heaters	No floor or online models available at Major home appliance stores. Cost was determined through internet search and direct contact with Bosch manufacturing.
Installation Costs	\$100-200	Cost assumes building can meet venting requirements	Oral interview with Bosch representative. February 2007.
Annual Operation and Maintenance	\$50-100	Costs deemed negligible, provided first installation is done correctly.	Oral interview with Bosch representative. February 2007.

Clothes Dryers

Table 83 Gas Dryers Costs Assumptions

	Cost	Comment	Sources
Initial Retail Cost	\$620	Kenmore Front Load Gas Dryer 5.7 cu.ft capacity 20,000 BTU	Survey of major home appliance stores and highest “value” selling floor model available at Sears, downtown Vancouver location. Visited March 2007
Installation Costs	\$100-150	Costs vary depending on venting requirements/upgrades	Oral interview while visiting Sears retail store, downtown Vancouver Location. Visited March 2007.
Annual Operation and Maintenance	\$50	Large retail stores offer maintenance agreements	Oral interview while visiting Sears retail store, downtown Vancouver Location. Visited March 2007.

Table 84 – Electric Water Heater Costs

	Cost	Comment	Source
Initial Retail Cost	\$550	Kenmore Front Load Gas Dryer 5.7 cu.ft capacity 4500 W	Survey of major home appliance stores and highest “value” selling floor model available at Sears, downtown Vancouver location. Visited March 2007
Installation Costs	\$100-\$150	Costs vary depending on wiring requirements	Oral interview while visiting Sears retail store, downtown Vancouver Location. Visited March 2007.
Annual Operation and Maintenance	\$50	Large retail stores offer maintenance agreements	Oral interview while visiting Sears retail store, downtown Vancouver Location. Visited March 2007.

Table 85 – Gas and Electric Dryer – Other Cost Assumptions

	Comments
Equipment and Installation Costs	The cost of gas dryers is assumed to be 10% higher than electric units mainly because the volume of sales for gas units is so low that the distribution costs are higher. The cost of installation will be very similar because the cost of the gas connection and exhaust venting will be similar to the cost of the wiring connection for an electric unit.
Maintenance Costs	No data was collected on the relative maintenance costs between electric and gas. It is assumed that they would be similar.

Pavement and Driveway Heating

Table 86 - Gas and Electric Pavement and Driveway Heating - Annual Energy Costs

	Pavement/Driveway and Heating	Electric
Lower Mainland	\$638	\$810
Interior	\$1,469	\$1,288
Vancouver Island	\$775	\$810

Table 87 –Gas and Electric Pavement and Driveway Heating - Cost Assumptions

	Comments
Equipment and Installation Costs	The cost of installing hot water piping system is assumed to be similar to the cost of installing electric heat tracing system.
Maintenance Costs	No data was collected on the relative maintenance costs between electric and gas. It is assumed that they would be similar.

Cogeneration in Commercial Institutional Facilities

Table 88 – Fuel Cost of Electricity From Commercial Natural Gas Project

Natural Gas Cost in \$/GJ	Fuel Cost of Electricity \$/MWh
\$10	\$48.0
\$11	\$52.8
\$12	\$57.6

Table 89 –Electricity Generation

	Cost of Electricity Produced from Commercial Cogeneration \$/MWh
Operating & Maintenance	\$22
Fuel Cost	\$50
Total	\$111

Water Heater – Instantaneous

Table 90 - Gas and Electric Water Heaters - Annual Energy Costs

	Gas Water Heaters	Electric
Lower Mainland	\$261	\$292
Interior	\$225	\$247
Vancouver Island	\$189	\$247

Table 91 Natural Instantaneous Water Heater Cost Assumptions

	Cost	Comment	Sources
Initial Retail Cost	\$950	Bosch AquaStar Tankless Water Heater 1600H LP	Floor model available at Home Depot, North Vancouver location. Visited March 2007
Installation Costs	\$100-200	Cost assumes building can meet venting requirements	Oral interview while visiting Home Depot retail store, North Vancouver Location. Visited March 2007.
Annual Operation and Maintenance	\$50-100	Manufacturers' recommendations vary. It should be noted that average tankless water heaters have a life expectancy of 20 years	Oral interview while visiting Home Depot retail store, North Vancouver Location. Visited March 2007.

Table 92 –Electric Instantaneous Water Heater – Cost Assumptions

	Cost	Comment	Sources
Initial Retail Cost	\$700-1300	Bosch Aquastar, American Tankless Water Heaters	No floor or online models available at Major home appliance stores. Cost was determined through internet search and direct contact with Bosch manufacturing.
Installation Costs	\$100-200	Cost assumes building can meet venting requirements	Oral interview with Bosch representative. February 2007.
Annual Operation and Maintenance	\$50-100	Costs deemed negligible, provided first installation is done correctly.	Oral interview with Bosch representative. February 2007.

Fireplaces

Table 93 – Gas and Electric Fireplaces - Annual Energy Costs

	Gas Fireplaces	Electric
Lower Mainland	\$163	\$77
Interior	\$240	\$79
Vancouver Island	\$198	\$77

Table 94 – Gas Fireplaces Costs Assumptions

	Cost	Comment	Source
Initial Retail Cost	\$850-2500	Initial cost vary dramatically according to size, venting type	Visits to fireplace specialty store (Solace Home Heating and Fireplaces). Visited February 2007.
Installation Costs	\$100-\$150	Costs vary depending on wiring requirements	Oral interview while visiting fireplace specialty store (Solace Home Heating and Fireplaces). February 2007.
Annual Operation and Maintenance	\$50	Large retail stores offer maintenance agreements	Oral interview while visiting fireplace specialty store (Solace Home Heating and Fireplaces). February 2007.

Table 95 – Electric Fireplaces Costs Assumptions

	Cost	Comment	Source
Initial Retail Cost	\$550	Chimney Free Vent Free Electric Fireplace 4,600 BTU 1350 W	Best selling and available floor model home depot, North Vancouver location. Visited February 2007
Installation Costs	n/a	Unit plugs into standard 110 V electric outlet	Oral interview while visiting Sears retail store, downtown Vancouver Location. Visited February 2007.
Annual Operation and Maintenance	n/a	n/a	Oral interview while visiting Sears retail store, downtown Vancouver Location. Visited February 2007.

Infra-Red

Table 96 –Gas and Electric Infra-Red Heating – Economic Comparison

	Comments
Initial Cost Comparison	The capital cost comparison is dependent on the availability of gas throughout a site but in general it is estimated that gas-fired infrared will be 50% more expensive.
Energy Costs	Gas and electricity costs vary depending on the size of the industrial site. At \$8.00 per GJ, Gas Infrared would cost the equivalent of 3.2 cents/kWh, which is about 15% less than BC Hydro's transmission electricity rate and 35% less than the BC Hydro's industrial distribution rate.
Annual Operation and Maintenance	It is estimated that the annual operating and maintenance costs would be similar.

APPENDIX D – FUEL COST COMPARISON

Fuel Cost Comparison

Lower Mainland

Gas	Efficiency	Consumption GJ/Year	Basic Charge	Delivery Charge	Rider 3	Rider 5	Commodity Charge	Rider 1	Midstream Charge	Rider 6	Rider 9	Subtotal	PST	Annual Cost
Space heating (forced air)														
Standard efficiency	65%	94.7		\$259	-\$10	\$14	\$725	\$0	\$81	\$0	\$0	\$1,069	\$75	\$1,144
Mid-efficiency	80%	76.9		\$210	-\$8	\$11	\$589	\$0	\$66	\$0	\$0	\$869	\$61	\$930
High-efficiency	90%	68.4		\$187	-\$7	\$10	\$524	\$0	\$59	\$0	\$0	\$772	\$54	\$826
High-efficiency	95%	64.8		\$177	-\$7	\$9	\$496	\$0	\$56	\$0	\$0	\$732	\$51	\$783
Domestic water heating														
Average stock efficiency	55%	26.3		\$72	-\$3	\$4	\$202	\$0	\$23	\$0	\$0	\$297	\$21	\$318
Standard efficiency	59%	24.5		\$67	-\$3	\$4	\$188	\$0	\$21	\$0	\$0	\$277	\$19	\$297
Mid-efficiency	62%	23.4		\$64	-\$3	\$3	\$179	\$0	\$20	\$0	\$0	\$264	\$18	\$282
High-efficiency	85%	17.0		\$47	-\$2	\$2	\$131	\$0	\$15	\$0	\$0	\$192	\$13	\$206
Domestic water heating														
Instantaneous Water Heaters	92%	15.7		\$43	-\$2	\$2	\$121	\$0	\$14	\$0	\$0	\$178	\$12	\$190
Clothes Dryers (SFD)		4.4		\$12	\$0	\$1	\$34	\$0	\$4	\$0	\$0	\$50	\$4	\$54
Hot Tubs/pool heater		52.5		\$144	-\$6	\$8	\$402	\$0	\$45	\$0	\$0	\$593	\$42	\$635
Pavement & Driveway Heating		52.8		\$144	-\$6	\$8	\$405	\$0	\$45	\$0	\$0	\$596	\$42	\$638
Fireplaces		13.5		\$37	-\$1	\$2	\$103	\$0	\$12	\$0	\$0	\$152	\$11	\$163
Air to Air Heat Pump		22.7		\$62	-\$2	\$3	\$174	\$0	\$20	\$0	\$0	\$257	\$18	\$275
Geothermal		17.2		\$47	-\$2	\$2	\$132	\$0	\$15	\$0	\$0	\$194	\$14	\$207

Assumptions:
Space heating end-use output consumption: 62 GJ/yr
Domestic water heating end-use output consumption: 14 GJ/yr

Rates used are:
Electricity : BC Hydro Rate Schedule 1101, effective February 1, 2007
Gas: Terasen Gas Rate 1 (Lower Mainland), effective January 1, 2007

Interior

Gas	Efficiency	Consumption GJ/Year	Basic Charge	Delivery Charge	Rider 3	Rider 5	Commodity Charge	Rider 1	Midstream Charge	Rider 6	Rider 9	Subtotal	PST	Annual Cost
Space heating (forced air)														
Standard efficiency	65%	78.8		\$216	-\$9	\$11	\$604	\$0	\$67	\$0	\$0	\$889	\$62	\$951
Mid-efficiency	80%	64.0		\$175	-\$7	\$9	\$490	\$0	\$54	\$0	\$0	\$722	\$51	\$773
High-efficiency	90%	56.9		\$156	-\$6	\$8	\$436	\$0	\$48	\$0	\$0	\$642	\$45	\$687
High-efficiency	95%	53.9		\$147	-\$6	\$8	\$413	\$0	\$46	\$0	\$0	\$608	\$43	\$651
Domestic water heating														
Average stock efficiency	55%	21.6		\$59	-\$2	\$3	\$165	\$0	\$18	\$0	\$0	\$244	\$17	\$261
Standard efficiency	59%	20.1		\$55	-\$2	\$3	\$154	\$0	\$17	\$0	\$0	\$227	\$16	\$243
Mid-efficiency	62%	19.2		\$52	-\$2	\$3	\$147	\$0	\$16	\$0	\$0	\$216	\$15	\$231
High-efficiency	85%	14.0		\$38	-\$2	\$2	\$107	\$0	\$12	\$0	\$0	\$158	\$11	\$169
Domestic water heating														
Instantaneous Water Heaters	92%	12.9		\$35	-\$1	\$2	\$99	\$0	\$11	\$0	\$0	\$146	\$10	\$156
Clothes Dryers (SFD)		3.7		\$10	\$0	\$1	\$28	\$0	\$3	\$0	\$0	\$41	\$3	\$44
Hot Tubs/pool heater		56.0		\$153	-\$6	\$8	\$429	\$0	\$48	\$0	\$0	\$632	\$44	\$677
Pavement & Driveway Heating		84.0		\$230	-\$9	\$12	\$644	\$0	\$71	\$0	\$0	\$948	\$66	\$1,014
Fireplaces		13.7		\$38	-\$1	\$2	\$105	\$0	\$12	\$0	\$0	\$155	\$11	\$166
Air to Air Heat Pump		22.7		\$62	-\$2	\$3	\$174	\$0	\$19	\$0	\$0	\$257	\$18	\$275
Geothermal		17.2		\$47	-\$2	\$2	\$132	\$0	\$15	\$0	\$0	\$194	\$14	\$207

Assumptions:

Space heating end-use consumption:

51 GJ/yr

Domestic water heating end-use consumption:

12 GJ/yr

Rates used are:
Electricity : BC Hydro Rate Schedule 1101, effective February 1, 2007
Gas: Terasen Gas Rate 1 (Lower Mainland), effective January 1, 2007

Vancouver Island

Gas	Efficiency	Consumption GJ/Year	Basic Charge	Energy Charge	Rider D							Subtotal	PST	Annual Cost
Space heating (forced air)														
Standard efficiency	65%	64.4		\$884	\$0							\$884	\$62	\$946
Mid-efficiency	80%	52.4		\$718	\$0							\$718	\$50	\$768
High-efficiency	90%	46.5		\$638	\$0							\$638	\$45	\$683
High-efficiency	95%	44.1		\$605	\$0							\$605	\$42	\$647
Domestic water heating														
Average stock efficiency	55%	21.6		\$296	\$0							\$296	\$21	\$317
Standard efficiency	59%	20.1		\$276	\$0							\$276	\$19	\$295
Mid-efficiency	62%	19.2		\$263	\$0							\$263	\$18	\$281
High-efficiency	85%	14.0		\$192	\$0							\$192	\$13	\$205
Domestic water heating														
Instantaneous Water Heaters	92%	12.9		\$177	\$0							\$177	\$12	\$189
Clothes Dryers (SFD)		3.8		\$52	\$0							\$52	\$4	\$56
Hot Tubs/pool heater		45.8		\$629	\$0							\$629	\$44	\$673
Pavement & Driveway Heating		52.8		\$724	\$0							\$724	\$51	\$775
Fireplaces		13.5		\$185	\$0							\$185	\$13	\$198
Air to Air Heat Pump		22.7		\$312	\$0							\$312	\$22	\$334
Geothermal		17.2		\$235	\$0							\$235	\$16	\$252

Assumptions:

Space heating end-use consumption:

42 GJ/yr

Domestic water heating end-use consumption:

12 GJ/yr

Rates used are:
Electricity : BC Hydro Rate Schedule 1101, effective February 1, 2007
Gas: Terasen Gas Rate 1 (Lower Mainland), effective January 1, 2007

Lower Mainland

Electric	Efficiency	Consumption kWh/Year	Basic Charge	Energy Charge	Subtotal	Rider	PST	Annual Cost
Space heating								
Electric furnace	100%	17,096		\$1,072	\$1,072	\$21	\$75	\$1,169
Air-source heat pump	200%	8,548		\$536	\$536	\$11	\$38	\$584
Geothermal heat pump	265%	6,451		\$405	\$405	\$8	\$28	\$441
Domestic water heating								
Standard efficiency	86%	4,678		\$293	\$293	\$6	\$21	\$320
Mid-efficiency	92%	4,373		\$274	\$274	\$5	\$19	\$299
High-efficiency	95%	4,234		\$266	\$266	\$5	\$19	\$290
Domestic water heating								
Instantaneous Water Heaters	92%	4,373		\$274	\$274	\$5	\$19	\$299
Clothes Dryers		886		\$56	\$56	\$1	\$4	\$61
Hot Tubs/Pool Heaters		6,530		\$410	\$410	\$8	\$29	\$446
Pavement & Driveway Heating		11,733		\$736	\$736	\$15	\$52	\$802
Fireplaces		1,123		\$70	\$70	\$1	\$5	\$77
Air to Air Heat Pump		6,319		\$396	\$396	\$8	\$28	\$432
Geothermal		4,769		\$299	\$299	\$6	\$21	\$326

Notes:

1GJ: 278 kWh

Interior

Electric	Efficiency	Consumption kWh/Year	Basic Charge	Energy Charge	Subtotal	Rider	PST	Annual Cost
Space heating								
Electric furnace	100%	14,223		\$892	\$892	\$18	\$62	\$973
Air-source heat pump	200%	7,112		\$446	\$446	\$9	\$31	\$486
Geothermal heat pump	265%	5,367		\$337	\$337	\$7	\$24	\$367
Domestic water heating								
Standard efficiency	86%	3,835		\$241	\$241	\$5	\$17	\$262
Mid-efficiency	92%	3,585		\$225	\$225	\$4	\$16	\$245
High-efficiency	95%	3,472		\$218	\$218	\$4	\$15	\$237
Domestic water heating								
Instantaneous Water Heaters	92%	3,585		\$225	\$225	\$4	\$16	\$245
Clothes Dryers		886		\$56	\$56	\$1	\$4	\$61
Hot Tubs/Pool Heaters		6,530		\$410	\$410	\$8	\$29	\$446
Pavement & Driveway Heating		18,667		\$1,171	\$1,171	\$23	\$82	\$1,276
Fireplaces		1,145		\$72	\$72	\$1	\$5	\$78
Air to Air Heat Pump		6,319		\$396	\$396	\$8	\$28	\$432
Geothermal		4,769		\$299	\$299	\$6	\$21	\$326

Notes:

1GJ: 278 kWh

Vancouver Island

Electric	Efficiency	Consumption kWh/Year	Basic Charge	Energy Charge	Subtotal	Rider	PST	Annual Cost
Space heating								
Electric furnace	100%	11,634		\$730	\$730	\$15	\$51	\$796
Air-source heat pump	200%	5,817		\$365	\$365	\$7	\$26	\$398
Geothermal heat pump	265%	4,390		\$275	\$275	\$6	\$19	\$300
Domestic water heating								
Standard efficiency	86%	3,835		\$241	\$241	\$5	\$17	\$262
Mid-efficiency	92%	3,585		\$225	\$225	\$4	\$16	\$245
High-efficiency	95%	3,472		\$218	\$218	\$4	\$15	\$237
Domestic water heating								
Instantaneous Water Heaters	92%	3,585		\$225	\$225	\$4	\$16	\$245
Clothes Dryers		886		\$56	\$56	\$1	\$4	\$61
Hot Tubs/Pool Heaters		6,530		\$410	\$410	\$8	\$29	\$446
Pavement & Driveway Heating		11,733		\$736	\$736	\$15	\$52	\$802
Fireplaces		1,123		\$70	\$70	\$1	\$5	\$77
Air to Air Heat Pump		6,319		\$396	\$396	\$8	\$28	\$432
Geothermal		4,769		\$299	\$299	\$6	\$21	\$326

Notes:

1GJ: 278 kWh

Appendix 3

BC GAS UTILITY LTD.
RESPONSE TO BCUC STAFF
INFORMATION REQUEST #1Response to Item 4.2 (cont'd)

BC GAS UTILITY LTD - 1996 SERVICE LINE INSTALLATIONS							
Service Line Cost	# of Installations	% of Total	Cum %	Total Service Line Costs	% of Total	Cum %	Average Cost /Service
<\$300	1042	20%		\$208,400	6%		
\$300-399	1261	24%	44%	\$441,350	13%	19%	
\$400-499	692	13%	57%	\$311,400	9%	28%	
\$500-599	503	10%	66%	\$276,650	8%	36%	\$353.86
\$600-699	333	6%	72%	\$216,450	6%	42%	\$379.60
\$700-799	256	5%	77%	\$192,000	6%	47%	\$402.80
\$800-899	195	4%	81%	\$165,750	5%	52%	\$423.17
\$900-999	187	4%	84%	\$177,650	5%	57%	\$445.21
\$1,000-1,099	153	3%	87%	\$160,650	5%	62%	\$465.23
>\$1,100	668	13%	100%	\$1,336,000	38%	100%	\$659.04
Total	5290	100%		\$3,486,300			

Note: In the table above the "Total Service Line Costs" are determined by multiplying the number of installations in each cost grouping by the mid-point value in that cost grouping (e.g. \$300-399 uses \$350). For the >\$1,100 grouping an average cost of \$2,000 is used.

It is evident from the analysis of 1996 year-to-date service line installation costs, which BC Gas believes is typical of previous construction periods, that an SLCA of \$1,100 would result in a yearly average installation cost of approximately \$465, less than the \$516 determined in the LRIC for a typical residential customer. However, an SLCA over \$1,100 results in an average cost in excess of \$600. BC Gas, therefore, recommends the SLCA for new Residential (Rate 1) and Small Commercial (Rate 2) customers, proposed for implementation effective January 1, 1997, be set at \$1,100 for the 1997 calendar year. New Rate 3 (Large Commercial) and above customer service line charges will be determined on an individual basis. The Company will review the actual service line installation costs near the end of 1997 and will apply to the Commission prior to January 1, 1998 to adjust the SLCA if necessary.

Schedule 2: New Mains Costs per Service Analysis

TERASEN GAS INC (TGI)

Year	Company	New Mains Installed	New Mains Dollars Spent	New Mains per metre Unit Cost	Services Installed Same Year	New Mains to New Service Ratio	Total Average New Mains Cost per Service
2006	TGI	164,550	\$7,765,000	\$47	12,525	13	\$620
2005	TGI	174,003	\$7,211,000	\$41	12,401	14	\$581
2004	TGI	156,604	\$5,264,000	\$34	13,201	12	\$399
2003	TGI	122,121	\$4,150,190	\$34	9,969	12	\$416
2002	TGI	127,532	\$4,574,000	\$36	9,035	14	\$506

TERASEN GAS Vancouver Island (TGVI)

Year	Company	New Mains Installed	New Mains Dollars Spent	New Mains per metre Unit Cost	Services Installed Same Year	New Mains to New Service Ratio	Total Average New Mains Cost per Service
2006	TGVI	41,529	\$3,399,000	\$82	3,131	13	\$1,086
2005	TGVI	48,568	\$3,604,000	\$74	3,944	12	\$914
2004	TGVI	37,993	\$2,437,000	\$64	3,593	11	\$678

Schedule 3

TERASEN GAS - 2006 SERVICE LINE INSTALLATIONS

JAN 1 - DEC 31

For Rates : 1 & 2

Service Line Costs	Number of Services	Percentage of Total	Cummulative Percentage	Total Service Line Costs	Percentage of Total	Cummulative Percentage	Average Cost per Service
< \$300	478	4%	4%	63,869	0%	0%	134
\$300 - 399	94	1%	5%	33,015	0%	1%	351
\$400 - 499	220	2%	7%	96,865	1%	2%	440
\$500 - 599	786	7%	14%	445,737	3%	5%	567
\$600 - 699	1814	16%	31%	1,177,142	9%	14%	649
\$700 - 799	2081	19%	50%	1,543,172	12%	26%	742
\$800 - 899	1263	11%	61%	1,041,663	8%	34%	825
\$900 - 999	638	6%	67%	602,463	5%	39%	944
\$1,000 - 1,099	524	5%	72%	547,577	4%	43%	1,045
\$1,100 - 1,199	326	3%	75%	373,294	3%	46%	1,145
\$1,200 - 1,299	277	3%	77%	346,108	3%	49%	1,249
\$1,300 - 1,399	260	2%	79%	283,202	2%	51%	1,089
\$1,400 - 1,499	170	2%	81%	246,397	2%	53%	1,449
\$1,500 - 1,599	140	1%	82%	215,037	2%	55%	1,536
\$1,600 - 1,699	133	1%	83%	200,664	2%	56%	1,509
\$1,700 - 1,799	128	1%	85%	224,274	2%	58%	1,752
\$1,800 - 1,899	126	1%	86%	236,544	2%	60%	1,877
\$1,900 - 1,999	99	1%	87%	191,135	1%	61%	1,931
\$2000 - 2,499	409	4%	90%	809,017	6%	68%	1,978
\$2,500 - 2,999	278	2.52%	93%	763,119	6%	74%	2,745
\$3,000 - 3,499	157	1%	94%	512,380	4%	78%	3,264
> \$3,500	<u>627</u>	<u>6%</u>	100%	<u>2,849,742</u>	<u>22%</u>	100%	<u>4,545</u>
Total	11,028	100%		12,802,415	100%		1,161

Contributions for Services > \$1,100

-4,097,452**Adjusted Total****8,704,963****100%****789**

Footnotes :

1) Total Service line costs include costs that were accumulated in orders that did not have specific risers posted ie standing jobs (\$1,728.813 , Incl \$2,227 for TGS .

These misc costs have been allocated based on the \$ balance of those jobs with riser counts (approx \$157 per order) .

Schedule 4

TERASEN GAS Vancouver Island (TGVI) - 2006 SERVICE LINE INSTALLATIONS

JAN 1 - DEC 31

For Rates : LCS-1, RGS, SCS-1, SCS-2

Service Line Costs	Number of Services	Percentage of Total	Cummulative Percentage	Total Service Line Costs	Percentage of Total	Cummulative Percentage	Average Cost per Service
< \$300	181	6%	6%	24,987	1%	1%	138
\$300 - 399	45	1%	8%	15,634	0%	1%	347
\$400 - 499	22	1%	8%	9,890	0%	1%	450
\$500 - 599	76	3%	11%	42,259	1%	2%	556
\$600 - 699	149	5%	16%	97,709	2%	4%	656
\$700 - 799	303	10%	26%	230,184	5%	9%	760
\$800 - 899	307	10%	36%	258,855	5%	14%	843
\$900 - 999	220	7%	43%	210,578	4%	19%	957
\$1,000 - 1,099	205	7%	50%	216,387	5%	23%	1,056
\$1,100 - 1,199	134	4%	55%	152,720	3%	27%	1,140
\$1,200 - 1,299	136	5%	59%	171,107	4%	30%	1,258
\$1,300 - 1,399	109	4%	63%	147,612	3%	33%	1,354
\$1,400 - 1,499	121	4%	67%	175,865	4%	37%	1,453
\$1,500 - 1,599	68	2%	69%	105,445	2%	39%	1,551
\$1,600 - 1,699	68	2%	71%	111,807	2%	42%	1,644
\$1,700 - 1,799	79	3%	74%	139,237	3%	45%	1,762
\$1,800 - 1,899	51	2%	76%	96,479	2%	47%	1,892
\$1,900 - 1,999	44	1%	77%	85,595	2%	49%	1,945
\$2,000 - 2,499	197	7%	84%	437,444	9%	58%	2,221
\$2,500 - 2,999	155	5%	89%	418,834	9%	67%	2,702
\$3,000 - 3,499	75	2%	91%	243,150	5%	72%	3,242
> \$3,500	258	9%	100%	1,331,248	28%	100%	5,160
Total	3,003	100%		4,723,029	100%		1,573

Contributions for Services > \$1,100

-780,603**Adjusted Total****3,942,426****100%****1,313**

Footnote :

- 1) Total Service line costs include costs that were accumulated in orders that did not have specific risers posted ie standing jobs (\$821,735). These misc costs have been allocated based on the \$ per orders with a riser count .
- 2) Categorization by cost per service based on the column labelled : Financial Unit Cost incl `no riser count` portion. This is due the fact that for the first few months of 2006 the services for TGVI were accounted for in blanket type orders ie... many units to one order number.

Schedule 5

Terasen Gas Inc.

Terasen Gas (Vancouver Island) Inc.

2007 Main Extension Test Results

Terasen Gas Inc.

ID Number (last 4 digits)	Company	Rate Class	# of Services	Total Direct Costs - 20 Yr. NPV	Main - Direct Cost	Services - Direct Cost	Meters & Regs - Direct Cost	Delivery Margin - 20 Yr. NPV	Original Cash Inflow - 20 Yr. NPV	Original Cash Outflow - 20 Yr. NPV	Original P.I
0543	TGI	1	6	\$ 6,617	\$ 2,507	\$ 3,450	\$ 660	\$ 33,710	\$ 16,019	\$ 7,485	2.14
1182	TGI	1	1	\$ 925	\$ 186	\$ 650	\$ 89	\$ 10,294	\$ 5,229	\$ 1,011	5.17
6937	TGI	1	4	\$ 5,144	\$ 1,200	\$ 3,492	\$ 452	\$ 20,815	\$ 9,768	\$ 5,956	1.64
5413	TGI	1	2	\$ 2,760	\$ 1,022	\$ 1,518	\$ 220	\$ 9,889	\$ 4,599	\$ 3,239	1.42
3443	TGI	1	38	\$ 41,759	\$ 11,792	\$ 27,280	\$ 2,687	\$ 181,256	\$ 85,086	\$ 47,534	1.79
3341	TGI	1	8	\$ 9,746	\$ 4,178	\$ 4,840	\$ 728	\$ 36,815	\$ 16,872	\$ 11,173	1.51
6603	TGI	1	9	\$ 13,550	\$ 6,035	\$ 6,525	\$ 990	\$ 63,691	\$ 31,212	\$ 16,006	1.95
2262	TGI	1	18	\$ 25,658	\$ 11,978	\$ 11,700	\$ 1,980	\$ 105,133	\$ 50,234	\$ 30,080	1.67
0221	TGI	1	5	\$ 5,144	\$ 1,749	\$ 2,950	\$ 445	\$ 26,448	\$ 12,430	\$ 5,755	2.16
5618	TGI	1	8	\$ 18,688	\$ 10,800	\$ 7,008	\$ 880	\$ 50,003	\$ 24,103	\$ 22,955	1.05
3771	TGI	1	32	\$ 12,379	\$ 4,327	\$ 4,532	\$ 3,520	\$ 170,089	\$ 80,859	\$ 14,702	5.50
1527	TGI	1	14	\$ 4,587	\$ 854	\$ 2,193	\$ 1,540	\$ 61,928	\$ 28,549	\$ 5,438	5.25
9556	TGI	1	2	\$ 3,044	\$ 1,372	\$ 1,500	\$ 172	\$ 10,757	\$ 5,190	\$ 3,629	1.43
3670	TGI	1	1	\$ 3,132	\$ 2,507	\$ 515	\$ 110	\$ 5,759	\$ 2,560	\$ 3,938	0.65
Devon St.	TGI	1	10	\$ 7,689	\$ 539	\$ 6,050	\$ 1,100	\$ 46,018	\$ 21,135	\$ 8,036	2.63
5893	TGI	1	1	\$ 1,243	\$ 443	\$ 711	\$ 89	\$ 4,462	\$ 2,032	\$ 1,431	1.42
6737	TGI	1	21	\$ 35,692	\$ 18,976	\$ 14,406	\$ 2,310	\$ 115,644	\$ 54,749	\$ 42,772	1.28
5344	TGI	1	45	\$ 54,459	\$ 22,284	\$ 27,225	\$ 4,950	\$ 355,847	\$ 165,189	\$ 94,936	1.74
24545	TGI	1	17	\$ 19,444	\$ 7,799	\$ 9,775	\$ 1,870	\$ 88,464	\$ 41,522	\$ 22,122	1.88
24305	TGI	1	4	\$ 5,719	\$ 1,922	\$ 3,357	\$ 440	\$ 21,564	\$ 10,177	\$ 6,723	1.51
22643	TGI	1	3	\$ 4,632	\$ 1,320	\$ 2,981	\$ 330	\$ 16,406	\$ 7,760	\$ 54,963	1.41
1448	TGI	1	1	\$ 2,428	\$ 1,493	\$ 825	\$ 110	\$ 6,755	\$ 3,289	\$ 3,004	1.09
1495	TGI	1	7	\$ 14,074	\$ 9,805	\$ 3,710	\$ 770	\$ 44,600	\$ 21,795	\$ 17,229	1.27
1785	TGI	1	6	\$ 5,039	\$ 929	\$ 3,450	\$ 660	\$ 33,882	\$ 16,117	\$ 5,388	2.99
1796	TGI	1	24	\$ 24,960	\$ 7,704	\$ 14,616	\$ 2,640	\$ 109,792	\$ 50,350	\$ 27,926	1.80
1812	TGI	1	51	\$ 60,023	\$ 25,088	\$ 29,325	\$ 5,610	\$ 265,392	\$ 124,560	\$ 68,607	1.82
1930	TGI	1	28	\$ 24,062	\$ 6,982	\$ 14,000	\$ 3,080	\$ 158,116	\$ 75,212	\$ 25,871	2.91
3245	TGI	1	39	\$ 51,675	\$ 17,355	\$ 30,030	\$ 4,290	\$ 228,597	\$ 109,295	\$ 60,125	1.82
3879	TGI	1	6	\$ 8,107	\$ 3,547	\$ 3,900	\$ 660	\$ 31,223	\$ 14,651	\$ 9,458	1.55
26454	TGI	1	3	\$ 5,396	\$ 1,337	\$ 2,250	\$ 1,807	\$ 20,622	\$ 10,329	\$ 6,510	1.59
26228	TGI	1	63	\$ 75,203	\$ 30,158	\$ 38,115	\$ 6,930	\$ 228,906	\$ 99,643	\$ 136,806	1.16
25893	TGI	1	1	\$ 1,243	\$ 443	\$ 711	\$ 89	\$ 4,462	\$ 2,032	\$ 1,433	1.42
25838	TGI	1	1	\$ 1,932	\$ 935	\$ 887	\$ 110	\$ 6,144	\$ 2,956	\$ 2,346	1.26
25366	TGI	1	13	\$ 21,172	\$ 10,357	\$ 9,165	\$ 1,650	\$ 69,027	\$ 31,734	\$ 25,278	1.26
24993	TGI	1	65	\$ 79,269	\$ 34,744	\$ 37,375	\$ 7,150	\$ 338,244	\$ 158,746	\$ 91,114	1.74
24947	TGI	1	18	\$ 11,077	\$ 4,272	\$ 4,825	\$ 1,980	\$ 41,707	\$ 15,879	\$ 13,614	1.17
24504	TGI	1	1	\$ 3,108	\$ 1,244	\$ 890	\$ 974	\$ 8,132	\$ 4,195	\$ 3,907	1.07
21945	TGI	1	6	\$ 13,983	\$ 2,723	\$ 5,416	\$ 5,844	\$ 36,653	\$ 18,526	\$ 17,253	1.07
18884	TGI	1	8	\$ 9,528	\$ 2,228	\$ 4,000	\$ 3,300	\$ 159,458	\$ 75,796	\$ 10,912	6.95
18549	TGI	1	2	\$ 2,693	\$ 27	\$ 1,566	\$ 1,100	\$ 52,213	\$ 24,770	\$ 3,140	7.89
18281	TGI	1	1	\$ 1,533	\$ 743	\$ 680	\$ 110	\$ 4,573	\$ 2,096	\$ 1,817	1.15
18260	TGI	1	4	\$ 10,561	\$ 5,943	\$ 4,100	\$ 518	\$ 17,799	\$ 7,523	\$ 12,955	0.58
17494	TGI	1	1	\$ 2,015	\$ 1,021	\$ 905	\$ 89	\$ 5,315	\$ 2,498	\$ 2,457	1.02
17422	TGI	1	1	\$ 2,396	\$ 1,207	\$ 1,100	\$ 89	\$ 3,860	\$ 1,507	\$ 2,963	0.51
17391	TGI	1	3	\$ 8,653	\$ 5,200	\$ 3,180	\$ 273	\$ 18,097	\$ 8,337	\$ 10,830	0.77
17328	TGI	1	1	\$ 1,291	\$ 330	\$ 741	\$ 220	\$ 10,408	\$ 4,916	\$ 1,497	3.28
16766	TGI	1	1	\$ 1,466	\$ 678	\$ 699	\$ 89	\$ 5,315	\$ 2,499	\$ 1,729	1.45
16452	TGI	1	1	\$ 5,210	\$ 2,510	\$ 705	\$ 1,995	\$ 102,003	\$ 5,322	\$ 6,695	0.79
15988	TGI	1	53	\$ 62,380	\$ 32,700	\$ 23,850	\$ 5,830	\$ 275,799	\$ 129,445	\$ 71,301	1.82
15774	TGI	1	61	\$ 32,606	\$ 7,500	\$ 18,396	\$ 6,710	\$ 123,111	\$ 43,719	\$ 38,718	1.13
15697	TGI	1	70	\$ 85,269	\$ 34,169	\$ 45,500	\$ 6,230	\$ 313,521	\$ 143,438	\$ 98,177	1.46
15571	TGI	1	2	\$ 5,760	\$ 910	\$ 3,970	\$ 880	\$ 25,126	\$ 10,673	\$ 7,209	1.48

Schedule 5 continued

Terasen Gas Inc.

Terasen Gas (Vancouver Island) Inc.

2007 Main Extension Test Results

14771	TGI	1	5	\$	5,193	\$	1,393	\$	3,250	\$	550	\$	22,675	\$	10,381	\$	5,808	1.79	
14146	TGI	1	1	\$	1,666	\$	929	\$	628	\$	110	\$	5,841	\$	2,790	\$	1,994	1.40	
13385	TGI	1	1	\$	2,714	\$	1,504	\$	1,100	\$	110	\$	7,000	\$	3,422	\$	3,385	1.01	
13250	TGI	1	2	\$	5,637	\$	3,431	\$	2,034	\$	220	\$	16,117	\$	8,033	\$	7,055	1.14	
13034	TGI	1	11	\$	10,617	\$	2,637	\$	7,480	\$	979	\$	61,930	\$	29,849	\$	11,842	2.52	
12968	TGI	1	5.98	\$	18,271	\$	3,471	\$	4,332	\$	10,468	\$	288,197	\$	139,673	\$	23,373	5.98	
12877	TGI	1	31	\$	54,491	\$	31,383	\$	20,750	\$	3,410	\$	159,512	\$	75,578	\$	65,871	1.15	
12501	TGI	1	15	\$	24,268	\$	10,093	\$	12,525	\$	1,650	\$	88,758	\$	42,483	\$	28,952	1.47	
12409	TGI	1	10	\$	10,015	\$	3,083	\$	5,833	\$	1,100	\$	52,847	\$	24,872	\$	11,125	2.24	
12234	TGI	1	10	\$	12,292	\$	3,853	\$	8,176	\$	1,081	\$	55,135	\$	26,781	\$	14,340	1.87	
11223	TGI	1	1	\$	2,041	\$	975	\$	846	\$	220	\$	10,408	\$	4,914	\$	2,492	1.97	
10321	TGI	1	24	\$	29,765	\$	11,885	\$	15,240	\$	2,640	\$	131,247	\$	62,097	\$	34,300	1.81	
9610	TGI	1	1	\$	1,884	\$	929	\$	845	\$	110	\$	5,469	\$	2,586	\$	2,283	1.13	
9570	TGI	1	1	\$	946	\$	186	\$	650	\$	110	\$	5,722	\$	2,727	\$	1,038	2.63	
9423	TGI	1	4	\$	7,922	\$	5,046	\$	2,436	\$	440	\$	24,881	\$	11,989	\$	9,645	1.24	
8646	TGI	1	52	\$	56,682	\$	18,570	\$	33,800	\$	5,720	\$	268,807	\$	127,300	\$	64,359	1.98	
8173	TGI	1	16	\$	20,991	\$	7,057	\$	9,403	\$	4,950	\$	186,888	\$	85,682	\$	79,491	3.50	
7535	TGI	1	1	\$	1,979	\$	1,290	\$	579	\$	110	\$	5,507	\$	2,606	\$	2,410	1.08	
6743	TGI	1	47	\$	50,026	\$	17,912	\$	28,623	\$	5,170	\$	197,803	\$	90,843	\$	56,713	1.60	
6403	TGI	1	31	\$	47,816	\$	17,250	\$	27,156	\$	3,410	\$	161,317	\$	75,683	\$	56,734	1.33	
5988	TGI	1	10	\$	20,590	\$	7,610	\$	6,270	\$	6,710	\$	344,466	\$	165,383	\$	25,153	6.58	
5875	TGI	1	1	\$	10,642	\$	9,879	\$	653	\$	110	\$	5,290	\$	760	\$	13,902	0.05	
5745	TGI	1	8	\$	12,350	\$	5,070	\$	6,400	\$	880	\$	56,614	\$	27,743	\$	114,654	1.89	
4549	TGI	1	48	\$	63,420	\$	24,300	\$	34,848	\$	4,272	\$	271,056	\$	128,697	\$	73,761	1.74	
9742	TGI	2	5	\$	114,977	\$	103,827	\$	5,500	\$	5,650	\$	1,005,891	\$	528,426	\$	151,411	3.49	
7235	TGI	2	1	\$	2,860	\$	1,671	\$	1,100	\$	89	\$	60,887	\$	31,680	\$	3,580	8.85	
3394	TGI	2	1	\$	3,534	\$	2,696	\$	728	\$	110	\$	54,751	\$	28,451	\$	4,473	6.36	
8959	TGI	2	12	\$	7,527	\$	4,873	\$	1,334	\$	1,320	\$	147,353	\$	73,403	\$	9,558	7.68	
3991	TGI	2	15	\$	10,912	\$	7,500	\$	1,762	\$	1,651	\$	89,371	\$	41,832	\$	14,038	2.98	
15657	TGI	2	2	\$	6,385	\$	4,432	\$	1,733	\$	220	\$	127,461	\$	66,360	\$	8,038	8.26	
1790	TGI	2	2	\$	7,780	\$	4,911	\$	1,859	\$	1,084	\$	48,636	\$	25,016	\$	9,899	2.53	
3869	TGI	2	5	\$	3,206	\$	2,072	\$	679	\$	455	\$	31,766	\$	14,959	\$	4,037	3.71	
28389	TGI	2	1	\$	1,353	\$	80	\$	1,100	\$	173	\$	5,395	\$	2,477	\$	1,579	1.57	
23041	TGI	2	17	\$	17,038	\$	3,022	\$	2,641	\$	11,374	\$	435,356	\$	224,970	\$	21,954	10.25	
22065	TGI	2	5	\$	14,368	\$	3,343	\$	9,925	\$	1,100	\$	97,353	\$	47,656	\$	17,980	2.65	
20078	TGI	2	1	\$	13,328	\$	10,233	\$	1,100	\$	1,995	\$	36,014	\$	18,890	\$	17,465	1.08	
19347	TGI	2	1	\$	5,135	\$	2,701	\$	434	\$	2,000	\$	35,214	\$	18,130	\$	6,596	2.75	
12640	TGI	2	2	\$	21,726	\$	20,126	\$	1,379	\$	220	\$	227,429	\$	118,961	\$	28,389	4.19	
11235	TGI	2	1	\$	5,521	\$	4,328	\$	1,082	\$	110	\$	7,790	\$	3,202	\$	7,108	0.45	
10828	TGI	2	1	\$	2,867	\$	2,161	\$	596	\$	110	\$	6,772	\$	3,127	\$	3,587	0.87	
8988	TGI	2	3	\$	19,590	\$	17,363	\$	1,898	\$	330	\$	268,143	\$	140,035	\$	25,340	5.53	
8908	TGI	2	8	\$	7,512	\$	5,600	\$	1,084	\$	828	\$	63,845	\$	30,791	\$	9,534	3.23	
5733	TGI	2	1	\$	11,422	\$	9,465	\$	398	\$	1,559	\$	601,878	\$	315,709	\$	14,936	21.14	
4540	TGI	2	3	\$	24,067	\$	19,016	\$	2,079	\$	2,972	\$	413,323	\$	210,507	\$	31,279	6.73	
5422	TGI	2	1	\$	8,424	\$	5,800	\$	1,100	\$	1,524	\$	134,337	\$	70,596	\$	10,959	6.44	
1022	TGI	3	1	\$	5,364	\$	4,457	\$	798	\$	110	\$	404,958	\$	208,130	\$	6,901	30.16	
27084	TGI	3	1	\$	3,143	\$	230	\$	918	\$	1,995	\$	70,961	\$	38,153	\$	3,953	9.65	
25834	TGI	3	1	\$	14,776	\$	6,702	\$	5,023	\$	3,051	\$	152,924	\$	80,636	\$	19,386	4.16	
12407	TGI	3	1	\$	10,666	\$	5,951	\$	1,123	\$	3,592	\$	139,273	\$	73,249	\$	13,934	5.26	
16168	TGI	1 & 2	2	\$	2,715	\$	867	\$	1,668	\$	180	\$	12,237	\$	5,763	\$	3,169	1.82	
15046	TGI	1 & 2	2	\$	20,176	\$	17,756	\$	2,200	\$	220	\$	31,783	\$	14,529	\$	26,333	0.55	
Total					1,266	\$	1,818,278	\$	856,477	\$	766,380	\$	202,238	\$	11,662,060	\$	5,648,088	\$	2,457,164

Aggregate P.I. - Original Data = 2.30

Schedule 5 continued

Terasen Gas Inc.

Terasen Gas (Vancouver Island) Inc.

2007 Main Extension Test Results

Terasen Gas (Vancouver Island) Inc.

ID Number (last 4 digits)	Company	Rate Class	# of Services	Total Direct Costs - 20 Yr. NPV	Main - Direct Cost	Services - Direct Cost	Meters & Regs - Direct Cost	Delivery Margin - 20 Yr. NPV	Original Cash Inflow - 20 Yr. NPV	Original Cash Outflow - 20 Yr. NPV	Original P.I.
1007	TGVI	LCS1	1	\$ 4,434	\$ 2,131	\$ 308	\$ 1,995	\$ 194,224	\$ 103,441	\$ 5,668	18.25
14571	TGVI	LCS1	1	\$ 7,397	\$ 6,700	\$ 587	\$ 110	\$ 73,627	\$ 39,374	\$ 9,597	4.10
4780	TGVI	RGS	4	\$ 7,386	\$ 4,127	\$ 2,876	\$ 383	\$ 20,094	\$ 10,220	\$ 8,810	1.16
5902	TGVI	RGS	18	\$ 20,387	\$ 13,421	\$ 4,986	\$ 1,980	\$ 73,174	\$ 35,613	\$ 23,125	1.54
3901	TGVI	RGS	2	\$ 3,194	\$ 2,067	\$ 980	\$ 148	\$ 11,585	\$ 6,042	\$ 3,848	1.57
10909	TGVI	RGS	3	\$ 5,153	\$ 3,596	\$ 1,317	\$ 241	\$ 14,486	\$ 7,414	\$ 6,230	1.19
6704	TGVI	RGS	35	\$ 54,155	\$ 29,610	\$ 21,630	\$ 2,915	\$ 215,552	\$ 111,226	\$ 64,292	1.73
Hammond Bay	TGVI	RGS	8	\$ 4,611	\$ 1,867	\$ 1,883	\$ 861	\$ 35,534	\$ 17,601	\$ 5,254	3.35
4669	TGVI	RGS	18	\$ 21,870	\$ 8,824	\$ 11,682	\$ 1,364	\$ 92,967	\$ 47,030	\$ 25,150	1.87
4455	TGVI	RGS	31	\$ 51,171	\$ 30,651	\$ 18,197	\$ 2,323	\$ 186,516	\$ 96,266	\$ 61,316	1.57
8935	TGVI	RGS	18	\$ 23,916	\$ 11,370	\$ 10,566	\$ 1,980	\$ 143,621	\$ 75,809	\$ 27,871	2.72
0473	TGVI	RGS	8	\$ 12,792	\$ 6,720	\$ 5,192	\$ 880	\$ 49,987	\$ 25,829	\$ 15,284	1.69
7533	TGVI	RGS	1	\$ 3,097	\$ 1,906	\$ 1,100	\$ 91	\$ 8,049	\$ 4,270	\$ 3,882	1.10
2473	TGVI	RGS	6	\$ 8,299	\$ 4,243	\$ 3,522	\$ 534	\$ 29,820	\$ 14,963	\$ 9,716	1.54
8115	TGVI	RGS	25	\$ 60,166	\$ 45,187	\$ 13,125	\$ 1,854	\$ 211,890	\$ 112,954	\$ 74,312	1.52
8347	TGVI	RGS	3	\$ 6,281	\$ 4,190	\$ 1,761	\$ 330	\$ 27,191	\$ 14,518	\$ 7,682	1.89
6076	TGVI	RGS	19	\$ 21,591	\$ 7,569	\$ 12,331	\$ 1,691	\$ 124,010	\$ 64,383	\$ 24,296	2.65
26764	TGVI	RGS	14	\$ 14,384	\$ 5,091	\$ 7,753	\$ 1,540	\$ 92,747	\$ 48,104	\$ 16,057	3.00
26704	TGVI	RGS	35	\$ 54,155	\$ 29,609	\$ 21,630	\$ 3,115	\$ 215,552	\$ 111,226	\$ 64,340	1.73
24490	TGVI	RGS	1	\$ 1,215	\$ 170	\$ 936	\$ 110	\$ 5,596	\$ 2,852	\$ 1,396	2.04
24238	TGVI	RGS	1	\$ 1,430	\$ 679	\$ 662	\$ 89	\$ 5,596	\$ 2,851	\$ 1,681	1.70
24238	TGVI	RGS	37	\$ 71,461	\$ 45,672	\$ 21,719	\$ 4,070	\$ 228,610	\$ 118,144	\$ 86,805	1.36
22210	TGVI	RGS	80	\$ 118,004	\$ 60,857	\$ 51,920	\$ 8,800	\$ 375,280	\$ 190,168	\$ 140,275	1.36
20722	TGVI	RGS	23	\$ 48,802	\$ 28,849	\$ 17,779	\$ 2,530	\$ 139,223	\$ 72,076	\$ 59,858	1.20
18840	TGVI	RGS	5	\$ 8,307	\$ 4,822	\$ 2,935	\$ 550	\$ 25,401	\$ 12,818	\$ 9,940	1.29
18376	TGVI	RGS	1	\$ 1,773	\$ 740	\$ 944	\$ 89	\$ 5,596	\$ 2,856	\$ 2,136	1.34
18270	TGVI	RGS	1	\$ 2,507	\$ 1,692	\$ 727	\$ 89	\$ 6,950	\$ 3,637	\$ 3,110	1.17
17610	TGVI	RGS	9	\$ 14,684	\$ 8,763	\$ 5,283	\$ 801	\$ 63,031	\$ 33,038	\$ 17,587	1.88
17514	TGVI	RGS	36	\$ 49,997	\$ 36,065	\$ 9,972	\$ 3,960	\$ 224,944	\$ 116,137	\$ 58,548	1.98
16230	TGVI	RGS	38	\$ 52,663	\$ 21,688	\$ 28,196	\$ 2,392	\$ 185,836	\$ 93,453	\$ 61,808	1.51
16081	TGVI	RGS	19	\$ 21,323	\$ 7,569	\$ 12,331	\$ 1,691	\$ 124,010	\$ 64,383	\$ 24,260	2.65
12603	TGVI	RGS	7	\$ 7,480	\$ 3,903	\$ 401	\$ 110	\$ 47,798	\$ 24,868	\$ 16,457	2.96
12560	TGVI	RGS	3	\$ 5,304	\$ 3,368	\$ 1,606	\$ 330	\$ 22,659	\$ 11,923	\$ 6,718	1.87
12476	TGVI	RGS	1	\$ 2,498	\$ 1,725	\$ 683	\$ 91	\$ 5,661	\$ 2,872	\$ 3,098	0.93
11780	TGVI	RGS	11	\$ 25,225	\$ 14,357	\$ 9,867	\$ 1,001	\$ 64,356	\$ 33,082	\$ 31,086	1.06
11358	TGVI	RGS	1	\$ 3,102	\$ 2,388	\$ 494	\$ 220	\$ 7,075	\$ 3,317	\$ 2,954	0.85
10104	TGVI	RGS	1	\$ 6,488	\$ 3,393	\$ 1,100	\$ 1,995	\$ 15,290	\$ 8,754	\$ 8,392	1.04
9707	TGVI	RGS	1	\$ 2,189	\$ 1,358	\$ 742	\$ 89	\$ 9,351	\$ 5,001	\$ 2,687	1.86
9058	TGVI	RGS	1	\$ 2,390	\$ 1,194	\$ 1,086	\$ 110	\$ 8,805	\$ 4,696	\$ 2,954	1.59
9024	TGVI	RGS	12	\$ 9,861	\$ 7,131	\$ 1,662	\$ 1,068	\$ 82,809	\$ 43,220	\$ 11,785	3.67
5764	TGVI	RGS	12	\$ 18,893	\$ 11,370	\$ 6,486	\$ 1,194	\$ 79,833	\$ 41,618	\$ 22,522	1.85
5618	TGVI	RGS	180	\$ 38,803	\$ 18,769	\$ 17,523	\$ 2,970	\$ 180,165	\$ 93,985	\$ 45,773	2.05
5130	TGVI	RGS	25	\$ 31,110	\$ 14,425	\$ 13,125	\$ 3,560	\$ 302,120	\$ 158,771	\$ 35,868	4.43
26080	TGVI	RGS	10	\$ 14,435	\$ 7,365	\$ 6,180	\$ 890	\$ 62,484	\$ 32,233	\$ 16,989	1.90
25629	TGVI	RGS	15	\$ 18,717	\$ 8,112	\$ 9,270	\$ 1,335	\$ 62,497	\$ 30,624	\$ 21,443	1.43
22708	TGVI	RGS	1	\$ 2,058	\$ 867	\$ 1,100	\$ 91	\$ 7,248	\$ 3,801	\$ 2,514	1.51
16355	TGVI	RGS	2	\$ 5,981	\$ 5,174	\$ 587	\$ 220	\$ 17,367	\$ 9,297	\$ 7,719	1.20
20722	TGVI	RGS	23	\$ 48,802	\$ 28,849	\$ 17,779	\$ 2,530	\$ 139,223	\$ 72,076	\$ 59,858	1.20
19233	TGVI	RGS	2	\$ 4,589	\$ 3,326	\$ 1,071	\$ 220	\$ 14,896	\$ 7,865	\$ 5,664	1.39
19042	TGVI	RGS	2	\$ 2,532	\$ 995	\$ 1,405	\$ 201	\$ 9,199	\$ 4,617	\$ 2,944	1.57
4139	TGVI	RGS	2	\$ 3,436	\$ 1,697	\$ 1,639	\$ 178	\$ 10,103	\$ 5,141	\$ 4,143	1.24
16905	TGVI	RGS	2	\$ 4,868	\$ 3,309	\$ 1,438	\$ 228	\$ 15,135	\$ 7,829	\$ 5,876	1.33
14571	TGVI	RGS	1	\$ 2,320	\$ 1,561	\$ 649	\$ 110	\$ 8,049	\$ 4,264	\$ 2,862	1.49
15183	TGVI	RGS	1	\$ 1,866	\$ 1,188	\$ 587	\$ 89	\$ 8,602	\$ 6,803	\$ 2,259	2.02
5441	TGVI	SCS2	1	\$ 2,530	\$ 2,162	\$ 277	\$ 91	\$ 30,487	\$ 17,485	\$ 3,139	5.57
Total				818	\$ 1,042,083	\$ 584,430	\$ 391,588	\$ 68,426	\$ 4,421,912	\$ 2,292,836	\$ 1,249,840

Aggregate P.I. - Original Data = 1.83