Terasen Gas

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June 15, 2009

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc.
2010 and 2011 Revenue Requirements and Delivery Rates Application

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Enclosed is the Terasen Gas Inc. ("Terasen Gas" or the "Company") 2010 and 2011 Revenue Requirements and Delivery Rates Application (the "Application" or "RRA"). This Application follows what has been a six year period where the Company was operating under the terms of a Performance Based Ratemaking ("PBR") settlement agreement.

Terasen Gas is seeking in this RRA an increase in its rates for delivery service for a two-year period commencing January 1, 2010. The increase sought for 2010 is 5.3%, with an additional effective base rate delivery increase of 4.1% (cumulative increase of 9.4%) in 2011. These proposed increases result in modest changes to the annual bill of an average Lower Mainland residential customer with an approximate net increase of 2.8% or $31 in 2010 and an additional 1.7% or $19 in 2011.[1]

TGI is open to a negotiated settlement of all of the issues, should the parties believe that is a possibility. Otherwise, TGI believes that this Application can be addressed efficiently and effectively through a written hearing process. There are three main reasons why this is the case.

1. The major contributors to the forecast revenue deficiency in 2010 and 2011 are external factors beyond the control of the Company. Mandatory changes to accounting standards, for instance, are the largest contributor. But for accounting changes associated with the adoption of International Financial Reporting Standards (IFRS), and additional costs related to the introduction of new codes and regulations and changes to government policy, the incremental revenue requirement outlined in this Application of $27.9 million for 2010 and $49.8 million for 2011 would have been a revenue surplus of more than $17.8 million in 2010 and a deficiency of $1.9 million in 2011. These changes in accounting policies will affect the timing of when costs are recovered and thereby affect the determination of TGI's revenue requirements and rates. Increases in the short-term are expected to be offset by lower rates in the future.

[1] Based on a typical annual consumption of a Lower Mainland residential customer consuming 95 GJ. This is also based on the current commodity and midstream charges effective April 1, 2009.

2. The total gross O&M expenses have increased from the level included in the 2009 projection; however, when considered on a per customer basis and after adjusting for inflation, the costs in both 2010 and 2011 are lower than those included in the 2003 Decision, which formed the basis for the PBR Agreement. Customers are thus obtaining permanent benefits from the efficiency gains obtained through the PBR Period.

3. A significant amount of historical and contextual information has been provided with this Application. The Commission and intervenors will have that information available to them when developing information requests. The value of having that information up front is also to allow all parties to focus on the issues rather than needing to request additional information during the IR process. TGI is also proposing a workshop for shortly after the filing of this Application, which should assist in focusing the discussion. TGI is committed to responding to relevant information requests to the best of its ability.

TGI is optimistic that the Commission will be in a position to make its determination regarding the type of hearing process following the procedural conference proposed for July 9, 2009. We believe that, at a minimum, the scope of any oral hearing should be carefully circumscribed by procedural order. The purpose of such a scoping order would be to limit an oral hearing to the most significant issues or to those issues that are anticipated to require additional process to elicit the evidence. The remaining issues would be efficiently addressed based on the written record.

Terasen Gas proposes a timetable that considers the proposed timing of all of the significant applications filed or being filed by the Terasen Utilities in 2009. The timetable acknowledges the corresponding workload required for the Commission and all parties. The proposed regulatory timetable will promote an efficient regulatory process.

The proposed timetable is as follows:

Action	Date (2009)
File Application	Monday, June 15, 2009
Procedural Order (up to Procedural Conference)	Thursday, June 18, 2009
Workshop	Monday, July 6, 2009
Intervenor Registration	Monday, July 6, 2009
Procedural Conference	Thursday, July 9, 2009
Procedural Order (Timetable and Process)	Wednesday, July 15, 2009
BCUC IR No. 1	Friday, July 17, 2009
Intervenor IR No. 1	Friday, July 24, 2009
TGI Response to IRs No. 1	Friday, August 14, 2009
BCUC IR No. 2	Friday, August 28, 2009

Action	Date (2009)
Intervenor IR No. 2	Friday, August 28, 2009
TGI Response to IRs No. 2	Friday, September 11, 2009
Negotiated Settlement Process or Hearing (proposed date range)	Monday, October 19, 2009 to Friday, October 30, 2009
TGI Final Argument Submissions	Friday, November 13, 2009
Intervenor Final Argument Submissions	Friday, November 27, 2009
TGI Reply Argument Submissions	Monday, December 7, 2009
Anticipated BCUC Decision	Friday, January 15, 2010

Since we are not expecting a Decision in time for permanent rates to be implemented for January 1, 2010, TGI respectfully requests an order pursuant to section 89 of the Act for interim rates for all non-bypass customers as proposed in this Application for 2010 effective January 1, 2010. Any refund or under-collection following the granting of interim rates would be addressed by way of a rate rider to refund or collect from customers the variance between the interim rates and the permanent rates ultimately approved.

Yours very truly,

TERASEN GAS INC.

Original signed:

Tom A. Loski

Attachments

cc (email only): Parties to the TGI 2004-2009 Multi-Year PBR Settlement

TERASEN GAS INC.

2010-2011
Revenue Requirements Application

Volume 1 - Application

June 15, 2009

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I. EXECUTIVE SUMMARY

With this Revenue Requirements Application ("RRA" or the "Application), Terasen Gas Inc. ("Terasen Gas" or "TGI" or the "Company") is seeking an increase in its rates for delivery service for a two-year period commencing January 1, 2010. The increase sought for 2010 is 5.3 per cent, with an additional effective base rate delivery increase of 4.1 per cent (cumulative increase of 9.4 per cent) in 2011. It results in relatively modest changes to the annual bill of an average Lower Mainland residential customer with an approximate net increase of 2.8 per cent or $31 in 2010 and an additional 1.7 per cent or $19 in 2011[1]. The forecasted costs underlying TGI's delivery rate proposals are reasonable and prudent. The contemplated investment in the business for 2010 and 2011 is necessary to ensure that the Company continues to be able to provide safe, reliable and cost effective service to its customers and to permit it to meet the evolving needs of its customers, stakeholders and shareholder.

Terasen Gas is the largest natural gas distribution utility in B.C., providing sales and transportation services to more than 830,000 customers in more than 100 communities throughout the Province. TGI has many decades of experience in the natural gas business and a proven record of offering a reliable supply of natural gas, delivered safely and efficiently at a reasonable cost. The efficiencies achieved during the past six years (the "PBR Period") under the performance-based rate ("PBR") settlement agreement (the "PBR Agreement")[2] have translated into a lower starting point for the Company's per customer Operations and Maintenance ("O&M") forecasts in 2010 (inflation adjusted) than was the case in 2003. TGI believes that it must build on that success and continue to invest in operational excellence and in delivering energy solutions to our customers.

The primary drivers of the requested rate increases for 2010 and 2011 are the significant changes taking place in the external operating environment. The single largest contributor to the requested rate increase, for instance, is accounting changes associated with the adoption of new accounting standards applicable to TGI. But for the accounting changes, the revenue requirement would have indicated a rate decrease for 2010 and a small increase for 2011. TGI must respond to the accounting changes. Our response to the evolving needs of customers, communities and changing government policy will define,

1 Based on a typical annual consumption of a Lower Mainland residential customer consuming 95 GJ. This is also based on current commodity and midstream charges effective April 1, 2009.

2 The two-year extension of the PBR Agreement, which came into effect January 1, 2008, was approved by the Commission pursuant to Order No. G-33-07 dated March 23, 2007. The original four year PBR Agreement, following a Negotiated Settlement Process, approved by the British Columbia Utilities Commission (the "Commission" or "BCUC") pursuant to Order No. G-51-03, dated July 29, 2003. For the purposes of this Application, the original four year PBR Agreement and the two year extended PBR Agreement will collectively be referred to as the "PBR Agreement". Additionally, throughout this Application the six year period commencing January 1, 2004 and ending December 31, 2009 will be referred to as the "PBR Period".

in large part, the long-term success of the Company. The proposals included in this Application provide the foundation for meeting the challenges and capturing the opportunities presented by TGI's external operating environment.

The remainder of this Executive Summary follows the organization of the Application.

External Situational Context

The external factors that compel a response from TGI in this Application include: BC's evolving provincial energy and environmental policies; Terasen Gas' level of competitiveness as an energy provider; the changing expectations of customers, regulators and other stakeholders; changing economic and demographic realities; and changes in financial accounting standards. These factors, taken together, place increasing demands, and pressure on our base gas business. At the same time, these factors present opportunities to provide new energy solutions to our customers that, in conjunction with gas, help customers achieve energy efficiency and reduce their impact on climate change. The key external factors driving our intention in 2010 and 2011 to continue investing in our core business and in alternative energy solutions are described briefly below. Additional details on Alternative Energy Solutions are provided in Part III, Section C, Tab 3 of this Application.

(a) Evolving energy and environmental policies

Energy policy at all levels of government is increasingly focused on addressing climate change through the reduction of greenhouse gas ("GHG") emissions, energy conservation, and the development of alternative (and renewable) energy sources. Provincial policy and recent amendments to the *Utilities Commission Act* (the "Act") have given utilities such as Terasen Gas the responsibility for implementing the Provincial government's energy objectives. In fact, energy policy calls upon utilities to play an integral role in doing this very thing.[3] The implications of these policies for Terasen Gas are profound, and TGI is compelled to respond.

Accordingly, this Application seeks British Columbia Utilities Commission ("BCUC" or the "Commission") approval to support and build on the portfolio of Energy Efficiency and Conservation ("EEC") programs approved in TGI's 2008 EEC Application. This Application also outlines a number of new initiatives that are aimed at providing customers with a range of energy solutions in addition to, and frequently in conjunction with, natural gas.

[3] For example, BC Energy Plan: A Vision for Clean Energy Leadership, Policy #3 (Encourage utilities to pursue cost effective and competitive demand side management opportunities) and Policy #4 (Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation) are policies objectives that give direction to the roles that utilities need to play.

Due to its inherent advantages (i.e. lowest emissions of the fossil fuels, no/low particulate matter), TGI believes that natural gas will continue to be a part of providing the province with a long-term and sustainable energy solution. Natural gas is well suited to providing consumers with clean air and affordable comfort. While alternative energy sources may emerge as the appropriate source for some applications, natural gas will remain the right energy source for many customer applications, either on its own or in tandem with other energy sources, given its relative stage of commercial and technological development. When fuel alternatives exist it is imperative that the appropriate rates and incentive mechanisms, as well as consistent messaging and appropriate customer support from TGI, are in place to encourage the efficient use of energy through market-based approaches. In this way, carbon reduction may be enhanced through energy choice.

(b) The changing expectations of customers, regulators, and other stakeholders

The expectations of customers, regulators, and other stakeholders are changing with increased concerns about GHG emissions and energy efficiency and a renewed interest in public safety and security. While many customers continue to see natural gas as the right fuel choice for particular applications, customers are also seeking out ways to reduce energy consumption and are examining energy choices that can be used as an alternative to, or in conjunction with, natural gas. Communities are becoming more engaged in energy planning and Terasen Gas must invest to ensure that it continues to meet these evolving expectations. This Application outlines a number of key areas of investment for 2010 and 2011.

(c) Terasen Gas level of competitiveness as an energy provider

TGI's competitive position in B.C. continues to decline with increases in natural gas prices and the gradual erosion of the cost advantage of natural gas over electricity. This is occurring, despite natural gas market prices improving relative to other energy commodities (such as oil) in the North American marketplace. Terasen Gas faces challenges in the B.C. marketplace due to the differing nature of how natural gas and electricity prices are set into customer rates. These factors reduce new customer additions, and the throughput levels of existing customers, as customers are incented to reduce their energy consumption or look for cheaper alternatives to meet their energy needs. All else equal, reduced demand for natural gas puts upward pressure on revenue requirements and delivery rates. These economic considerations are compounded by how the reality of climate change and the focus on GHG emissions can change some customers' perception of natural gas. TGI believes that it must invest in and adapt its business model to meet these challenges.

The Terasen Utilities (TGI, Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW")) filed a separate application with the Commission on May 15, 2009, seeking to correct the mechanism for determining Return on Equity ("ROE") and, for Terasen Gas, to increase the equity component of its capital structure to allow the Terasen Utilities an opportunity to earn a fair return on investment (the "ROE Application"). This Application does not discuss the ROE Application or any resulting impacts on the Company's revenue requirements and rate proposals. However, following a decision on the ROE Application, the Company proposes to incorporate the results of that decision in its 2010 and 2011 revenue requirements and rate proposals. The opportunity to earn a fair return is integral to the financial health of Terasen Gas. Maintaining the financial health of TGI ultimately has a beneficial impact on customers.

(d) Changing Economic and Demographic Realities

There have been significant changes in global, regional, and local economic conditions since the last Revenue Requirement Application was filed in 2003. These changes have meaningful implications for Terasen Gas' customers. It will impact their ability to pay for energy, impair their ability to make investments in energy conservation measures, lower customer additions and reduce customer demand for energy consumption. In addition to this economic downturn, Terasen Gas faces demographic challenges as do other employers across the country. We must develop different strategies to manage these realities to ensure that we can continue to meet the needs of our customers.

(e) Changes in financial accounting standards

Canadian accounting standards are entering a time of unprecedented change. Canadian utilities will be required to comply with International Financial Reporting Standards ("IFRS") for financial reporting periods commencing on or after January 1, 2011. Comparative figures for 2010 must also be restated to be in compliance with IFRS. These changes in accounting policies will affect the timing of when costs are recovered and thereby affect the determination of the Company's revenue requirements and rates. Related to this issue, it is expected that rates will rise in the short term, but that this will be offset by lower rates in the future. Accounting changes are the most significant driver of the rate increases sought for 2010 and 2011.

Respected and Trusted Operator

The Company takes pride in providing safe, reliable and cost effective utility service to customers on fair and reasonable terms. Since 2004, both the customers and shareholders of Terasen Gas have benefited from the current PBR Agreement. During this time, service quality levels have generally been met, customer satisfaction levels have increased and customer delivery rates have remained essentially flat.

Part III, Section B of this Application addresses the Company's role as a respected and trusted operator by reference to the following five key areas of focus:

1. Company's Corporate Governance Structure and Management Processes and Controls;
2. Delivery of Customer Service and Delivery Rates paid by our Customers;
3. Operational Performance;
4. Employee Impacts; and
5. Financial Results, for the benefit of customers and our shareholder.

Part III, Section B addresses these five areas of focus in the context of the past and the future. "The Past" describes how Terasen Gas has responded successfully to various challenges throughout the PBR Period. Our response to ongoing challenges, and how those challenges will shape our future actions, are discussed under "The Future" heading.

The Past

(a) The Company's Corporate Governance Structure and Management Processes and Controls

Terasen Gas is committed to continuous improvement and Operational Excellence for the benefit of its customers and shareholders. For Terasen Gas, Operational Excellence means the prudent combination of service quality to our customers, and the cost of providing those services, while ensuring employee and public safety, and operating in an environmentally responsible manner. TGI's strong corporate governance structure, with clear division of management responsibilities and well defined policies and procedures that are monitored for performance, is important for achieving Operational Excellence.

During the PBR Period there have been a number of significant changes in the external environment experienced by TGI. The Company has successfully managed these challenges, while delivering Operational Excellence. The efficiencies achieved to date, through activities such as the Utilities Strategy Project ("USP")[4] provide evidence of Operational Excellence and the effectiveness of the new management structure now in place. While the needs of our customers and shareholder will continue to evolve, Terasen Gas believes the management structure and processes currently in place will provide a solid foundation to ensure the delivery of safe, reliable and cost effective service to customers.

(b) The Delivery of Customer Service and Delivery Rates Paid by our Customers

Customers have realized significant value over the PBR Period in the Company's delivery of safe, reliable and cost effective service. Over the PBR Period, Terasen Gas has achieved record high levels of customer satisfaction and has generally met or exceeded the levels set out in the Service Quality Indicators ("SQIs"). At the same time, customers also saw delivery rates hold steady when compared to

[4] USP was a major re-design of the management structure of the Company at the end of 2003.

inflation. All of this has been accomplished in a period where overall normalized demand for natural gas has declined, the rate of customer growth (which peaked in 2005) has declined in the last four years of the PBR Period, and the expectations of customers have evolved. However, with this success comes increased expectations and, when combined with changing customer expectations, evolving government policy, and changes in the competitive environment, Terasen Gas will have to invest more in its customer care service in order to improve the current levels of service to meet the evolving needs of customers. As part of this goal, the Company filed its Customer Care Enhancement Project Application on June 2, 2009, with the expectation that the new project components will be in service on January 1, 2012.

(c) Operational Performance

Underpinning Terasen Gas' success to date is the Company's ability to consistently excel in operational performance by proactively responding to evolving regulatory and business needs. Code compliance, carbon management, sound development and execution of an Information Technology ("IT") strategy, and delivering on major projects are fundamental to Terasen Gas being regarded as a respected and trusted operator.

Terasen Gas has a solid history of code compliance and has implemented management systems and/or operating practices to ensure compliance including an Integrity Management Plan ("IMP") and an Environmental Management Plan ("EMP"). The Company has a long standing history of being proactive in the area of operating emissions management and continues to be proactive in looking for improved ways to provide safe, reliable, cost effective and environmentally responsible service.

Terasen Gas has implemented an IT strategy that focuses on adopting industry best practices. Key aspects of this strategy are scheduled refreshes of key equipment, infrastructure and application software, and standardization of processes and infrastructure where appropriate.

Terasen Gas also has an established record for successfully implementing major capital projects, helping to provide safe, reliable and efficient gas service to customers. Over the PBR Period, Terasen Gas has maintained its track record by implementing a number of major capital projects successfully including the Low Pressure System Renewal, Distribution Mobile Solution, Nucleus Deal Capture, Transmission Automated Mapping/Facilities Management ("AM/FM"), Customer Attraction Front End ("CAFÉ"), Service Delivery Enhancement and Commodity Unbundling.

(d) Employee Impacts

Operational Excellence and meeting the needs of our customers requires investment in our human resources. During the PBR Period, Terasen Gas has focussed on retaining, attracting, and motivating employees. The key areas where Terasen Gas has demonstrated its commitment to its employees are in employee safety, managing changing employee demographics, and developing talent. Terasen Gas has set increasingly challenging safety goals, undertaken a variety of steps to mitigate demographic challenges, taken a proactive approach to disability management and maintained a strong focus on employee development and training.

For the purposes of compensation and benefits, Terasen Gas' workforce is separated into three primary groups: executives, management and exempt ("M&E") employees and unionized employees represented by the International Brotherhood of Electrical Workers ("IBEW") and Canadian Office and Professional Employees ("COPE"). While the details of the compensation and benefits programs vary between these three groups, the Company applies the same philosophy and approach to compensation and benefits for all employees. This approach includes a total compensation package that rewards employees with competitive base salaries and wages, incentive compensation, benefits, and paid time-off.

In 2006 and 2007, Terasen Gas reached five-year labour agreements with the IBEW and COPE respectively. These agreements introduced significantly greater flexibility in work management, and in implementing common flexible benefits and post-retirement benefit plans.

The Company has demonstrated a prudent and responsible approach in managing overall employee costs, including headcount during the PBR Period. Terasen Gas has taken steps to create an efficient and effective talent management structure which has allowed us to meet our objectives of retaining, attracting, and motivating employees, which has in turn supported the Company's goal of achieving Operational Excellence.

(e) Financial Results: For the Benefit of Customers and our Shareholder

A key element of the PBR Agreement was the establishment of the earnings sharing mechanism ("ESM"). The ESM allowed for a 50:50 sharing between customers and the Company in earnings above and below the allowed ROE, beginning in 2004. The PBR Agreement structure and the ESM were designed to encourage efficiencies over a longer term, and to enhance the speed and opportunity for pay back on investments in efficiencies from realized savings.

Savings have been achieved in both O&M and capital expenditures, resulting in depreciation savings and rate base reductions. Total earnings available for sharing during the PBR Period are expected to be close to $138 million, of which an estimated $69 million benefit will have accrued to customers.[5] Projected Gross O&M expenses of $195.1 million for 2009 are significantly lower than the 2003 Decision[6] in real dollars ($204.7 million). This has been achieved despite the actual labour inflation during the PBR Period (approximately 3 per cent) being a full percentage point higher than the average Consumer Price Index ("CPI") from the Annual Reviews, which has been used to adjust to the real O&M expenses. This additional labour inflation has been absorbed through the productivity improvements and efficiency gains during the PBR Period. On a per customer basis, the efficiency gains achieved through O&M are even more significant, showing, in real terms, a decrease from $266 per customer in 2003 to $234 per customer in 2009.

The Future

Terasen Gas is proud of the level of service and savings provided to customers during the PBR Period. The Company recognizes that service can, and we believe it should, continue to be enhanced to meet evolving customer needs. While Terasen Gas will strive for continuous improvement in its pursuit of Operational Excellence, the Company has exhausted opportunities for significant incremental efficiency gains. The time has come to make investments in Terasen Gas' business to meet the evolving needs of our customers. TGI cannot remain a respected and trusted operator by being complacent. TGI's external situational context presents major challenges. It is critical to meet the long-term interest of our customers that we enhance and capture opportunities as they present themselves. This Application outlines our proposals for 2010 and 2011. The plan calls for investment in management controls, enhanced customer service to address the evolving needs of customers, related operational impacts, and human resources. The discussion of our plan for 2010 and 2011 builds on the same factors addressed in the context of "The Past".

(a) The Company's Corporate Governance Structure and Management Processes and Controls

Terasen Gas must continue to invest in the controls and management constructs (including IT Systems) that are necessary to ensure that TGI continues to meet and, when appropriate, exceed corporate governance and regulatory requirements while enabling growth.

As a responsible operator, Terasen Gas must continue to increase its efforts to improve safety measures. Terasen Gas must take the necessary steps to ensure an appropriate level of security for both its

5 Part III, Section B, Tab 1, Table B-1-9: Customers Realized $69 million in Savings as a result of the ESM
6 2003 Revenue Requirements Application Decision and Order No. G-7-03, dated February 4, 2003

physical assets (pipes, stations and buildings) and soft assets (computer systems and infrastructure). This includes enhancing its capabilities related to disaster recovery, business continuity and emergency response programs. TGI also believes there is a need to increase the awareness of customers and the public with respect to gas safety matters in order to enhance public safety.

(b) The Delivery of Customer Service and Delivery Rates Paid by our Customers

Excellence in customer service requires not only satisfying SQIs today, but also being able to meet evolving customer needs and expectations as they arise. One area for improvement is in TGI's outsourced meter-to-cash[7] activities. Terasen Gas does not regard the current comprehensive outsourcing arrangement and legacy customer information system ("CIS") platform as a sustainable solution going forward. Transitioning away from a comprehensive outsourcing arrangement is a critical component of the Company's long-term strategic direction. The Customer Care Enhancement Project is part of the solution that is contemplated to go into effect in 2012. In the shorter term, as reflected in this Application beginning in 2009 and through the 2010/2011 forecast period, the Company will be increasing its efforts to improve the quality of our customer care activities while bridging to an orderly transition for implementation of the new customer care delivery model effective 2012. The details are described in Part III, Section C, Tab 9.

Customers are increasingly expecting Terasen Gas to provide information and advice, and deliver a range of energy solutions including gas, energy efficiency and conservation measures, and alternative energy sources. In accordance with the Commission's direction in response to the Company's recent EEC Application, Terasen Gas seeks approval in this Application to expand the existing portfolio of cost-effective EEC programs and spending for 2010 and 2011. The details of the proposal are described in Part III, Section C, Tab 3 of the Application.

In response to changing expectations, the Company also proposes to offer integrated and comprehensive, alternative energy solutions in conjunction with the use of natural gas. This will allow customers to consider the use of natural gas alone or with a complementary fuel choice in an integrated solution where natural gas may otherwise not have been considered. This is supported by the policy statement from the 2007 BC Energy Plan that states:

> *"It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of*

[7] Meter-to-Cash – A phrase used to describe the customer service processes that are involved between reading the customer's utility meter and receiving payment from the customer.

alternative energy sources with natural gas include solar thermal and geothermal. Working with municipalities, utilities, and other stakeholders the provincial government will promote energy efficiency and alternative energy systems, such as solar thermal and geothermal throughout the province."[8]

There is a growing acceptance that comprehensive energy planning must occur within communities or at a community level. The QUEST (Quality Urban Energy Systems of Tomorrow) White Paper I states that:

- *"The community, with its use of energy in houses, business, institutions, industry and transportation, is the most promising place to act."*
- *"An integrated approach at that level allows balancing energy demand and supply between different sectors, accounting for the impact of one system versus the other, and leads to optimal results in providing community services."*
- *"Integration of energy systems at the community level brings the maximum economic, social and environmental benefits."*[9]

Indeed, the majority of BC municipalities have committed to the provincial government to become carbon neutral by 2012.[10] This obligation will be reflected in local bylaws and thus change the way developers must plan for energy requirements. Local governments have long been important partners for Terasen Gas, but they have now become even more critical.

Using a community view, or QUEST approach[11], and the SMART Gas Strategy for BC[12] , utilities like Terasen Gas can play a significant role in developing community energy solutions to meet community and customer needs. We are well positioned to be delivering these solutions given our broad

8 See Appendix C-2 for a copy of Energy Plan 2007: A Vision for Clean Energy Leadership, page 21

9 See Appendix C-22 for a copy of QUEST White Paper I

10 See Appendix C-15 for a copy of British Columbia Climate Action Charter
Over 120 local governments have Charters with the provincial government that include the following commitments:
(a) fostering co-operative inter-governmental relations;
(b) aiming to reduce GHG emissions, including both their own and those created by others;
(c) removing legislative, regulatory, policy, or other barriers to taking action on climate change;
(d) implementing programs, policies, or legislative actions, within their respective jurisdictions, that facilitate reduced GHG emissions, where appropriate;
(e) encouraging communities that are complete and compact and socially responsive; and
(f) encouraging infrastructure and a built environment that supports the economic and social needs of the community while minimizing its environmental impact.

11 See Appendix C-22 for a copy of QUEST White Paper I and Appendix C-49 for a copy of QUEST White Paper II

12 See Appendix C-14 for a copy of A Vision for British Columbia's Energy Future: Smart Gas Strategies

geographic footprint, skilled workforce, knowledge and experience. Our customers' interests are best served by Terasen Gas being - and being perceived by municipalities and communities as - a provider of solutions for natural gas and/or alternative energy delivery.

The Company has begun to undertake projects that reflect this commitment and expects to offer the following alternatives in the next several years:

1. Bio-gas ;
2. LNG and CNG for transportation tariffs;
3. Solar thermal; and
4. Geo Thermal and District Heating.

As set out in Part III, Section C, Tab 3, the Company proposes a regulatory model for assessing opportunities in these areas. This model includes specific economic tests. The biogas model, in Pilot Phase, involves a cap on cost of supply and a limit on quantity. The purpose of these tests will be to ensure that the cost of providing service to prospective customers will not unduly impact existing customers, while the addition of new customers to share in delivery costs helps to offset the impacts of declining use rates on the existing customer base. As set out in Part III, Section C, Tab 12, Terasen Gas seeks approvals for various new rate schedules and the costs associated with providing these services to customers. We believe that it is in the interest of both existing and future customers that Terasen Gas not only be able to offer these services, but that the programs, development and sales costs of these activities for the forecast period form part of the costs to be recovered from customers as part of this RRA .

(c) Operational Performance

Terasen Gas will continue to act as a responsible corporate citizen, having regard for the environmental impacts of its activities in the communities in which it does business. As the future unfolds with increases to the Provincial Carbon Tax and the anticipated introduction of Cap and Trade systems, the Company must ensure it continues to provide leadership in its environmental stewardship activities, even though these activities will cause upward pressure on the Company's costs.

(d) Employee Impacts

TGI, like many companies, is entering a critical stage in a labour market that is challenged on two fronts by an aging workforce and a limited supply of younger, skilled workers graduating from trades and technology programs. In order to maintain the safe, secure and reliable service our customers expect, TGI needs to strengthen the foundation of its end-to-end Talent Management systems and processes.

This need lies at the heart of the long-term Human Resources vision to, "Retain, attract, develop and motivate the right people to achieve desired business results".

(e) Financial Results: For the Benefit of Customers and our Shareholder

Terasen Gas is prudently managing costs and resources and drawing on improvements made over the course of the PBR Period. TGI is committed to continuing to provide for efficiencies and benefits to customers and recognizes that to do so it must invest to meet the challenges and evolving expectations of its customers. The investment proposed in this Application is in the long-term best interests of customers and the Company. The Company must also reflect the changes to accounting standards in order to be compliant with IFRS, although this will cause upward pressure on revenue requirements and customer rates during the period of this RRA.

Continued Investments in Base Business and New Energy Solutions

TGI has determined that the Company's delivery margin revenue deficiency is $27.9 million in 2010 and a further $21.9 million in 2011, ($49.8 million on a cumulative basis) when compared to revenue from existing 2009 delivery rates. This is equivalent to an approximate effective base delivery rate increase of 5.3 per cent in 2010 and an additional effective base rate delivery increase of 4.1 per cent (cumulative increase of 9.4 per cent) in 2011.

To implement these increases, TGI proposes that the basic charge and administration fees be held at existing approved 2009 levels and that the volumetric and demand based delivery rates be adjusted to recover the revenue requirement increase in 2010 and 2011. TGI believes that this proposal is consistent with the 2007 BC Energy Plan Policy Action Item 4, which called on utilities to implement innovative rate designs.[13] TGI believes this rate design supports its energy efficiency efforts and meets the evolving expectations of customers.

As TGI emerges from six years under the PBR Agreement, this Application demonstrates that the overall picture is a favourable one with respect to the management of the Company's controllable costs. This is reflected in the fact that the primary factors driving the requested rate increases for 2010 and 2011 are factors that TGI would characterize under the existing PBR Agreement as "exogenous factors". They

[13] Policy item #4 from Energy Plan 2007: A Vision for Clean Energy Leadership- Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation. All utilities are encouraged to explore, develop and propose to the Commission additional innovative rate designs that encourage efficiency, conservation and the development of clean or renewable energy.

represent the significant changes in the external operating environment and TGI's proposed response to them for 2010 and 2011.

The major contributor to the forecast revenue deficiency in 2010 and 2011 is mandatory changes to accounting standards. The most significant of these accounting standard changes are:

- reductions in the amount of overheads capitalized; and
- increases in depreciation expense.

These two items, in aggregate, account for a cumulative impact of $42.9 million in 2010 and $43.4 million in 2011. Accounting changes also impacted the forecast gross level of O&M expenses, as has the introduction of new codes and regulations and changes to government policy. In total, these three factors have contributed to an increase in the 2010 revenue requirements of $2.8 million and $4.5 million in 2011. But for these changes, the cumulative revenue requirement outlined in this Application of $27.9 for 2010 and $49.8 million for 2011 would have been a revenue surplus of $17.8 million in 2010, and a deficiency of $1.9 million in 2011.

This Application also shows that customers have obtained a permanent benefit of significant savings during the PBR Period through prudent management. Indeed, the most significant offsetting factor in the 2010 and 2011 revenue requirement is savings resulting from the rebasing of the savings achieved through the PBR Period. These savings total approximately $22.4 million and are composed of $6.7 million related to net O&M savings and $19.3 million related to capital savings, offset by changes in late payment charges and income taxes.

The result is that the efficiencies achieved through the PBR Period have translated into a lower starting point for our per customer O&M forecasts in 2010 (inflation adjusted) than was the case in 2003. Thus, while the total gross O&M expenses have increased from the level included in the 2009 projection, when adjusted for inflation the per customer O&M costs in both 2010 ($245) and 2011 ($249) are lower than those included in the 2003 Decision ($266). Terasen Gas views this result as a significant demonstration of the legacy of efficiency gains realized through the PBR Period, continuing to be in effect into the future for the benefit of customers.

TGI notes that another offsetting factor is an increase in sales margin and other revenues caused by increases in the customer base and increases in commercial use rates and SCP revenues. These amounts total $12.7 million in 2010 and $15.1 million in 2011.

The details of these results and the proposals that have been summarized above, are set out in Part III, Section C of the Application, entitled Continued Investments in Base Business and New Energy Solutions. It provides detailed forecasts of demand and cost structure for the forecast period, accompanied by an explanation of why the costs are appropriate and reasonable. We also present, in detail, our proposed responses to the significant challenges identified in the external situational context section of the RRA.

The Approvals Sought

Part III, Section D, details the specific requests for which we are seeking Commission approval. As stated above, we believe that the forecasted costs included in this Application, which underpin our delivery rate proposals, are prudent and required to meet the evolving needs of our customers and shareholder.

II. INTRODUCTION

Terasen Gas is the largest natural gas distribution utility in BC, providing sales and transportation services to more than 830,000 customers in more than 100 communities throughout the Province.[14] TGI has many decades of experience in the natural gas business with a proven record for offering a reliable supply of natural gas, delivered safely and efficiently at a reasonable cost. TGI's commitment to maintain that proven record through changing circumstances is reflected in the proposals set out in this Application.

Terasen Gas is seeking in this RRA an increase in its rates for delivery service for a two-year period commencing January 1, 2010. The increase sought for 2010 is 5.3 per cent, with an additional effective base delivery rate increase of 4.1 per cent (cumulative increase of 9.4 per cent) in 2011. These proposed increases result in relatively modest changes to the annual bill of an average Lower Mainland residential customer with an approximate net increase of 2.8 per cent or $31 in 2010 and an additional 1.7 per cent or $19 in 2011.[15]

TGI will invest to maintain safe, reliable and cost-effective service to customers, and to meet the challenges presented by our operating environment. TGI's response to the changing environmental and energy spectrum outlined in this Application also includes investment in EEC initiatives. TGI has presented in this Application rate structures and regulatory models to support new alternative energy solutions, such as gas compression service for Natural Gas Vehicles, biogas upgrading, geothermal and district energy systems. These new service offerings will augment TGI's base natural gas business, and help our customers to meet challenges and capture opportunities presented by a new focus on climate change and alternative energy sources. As this RRA demonstrates, the forecasted costs underlying these delivery rate proposals and the proposed service offerings are reasonable and prudent and necessary to meet the evolving needs of TGI's customers, stakeholders and shareholder. The specific orders sought are included in Part III, Section D.

The PBR Agreement under which TGI currently operates[16] comes to an end on December 31, 2009. Customers have obtained permanent benefits from the efficiency gains obtained through the PBR

[14] See Appendix B-1 for a copy of Company History and Appendix B-2 for a copy of TGI Service Areas.

[15] Based on a typical annual consumption of a Lower Mainland residential customer consuming 95 GJ. This is also based on the current commodity and midstream charges effective April 1, 2009.

[16] The two-year extension of the PBR agreement, which came into effect January 1, 2008, was approved by the Commission pursuant to Order No. G-33-07 dated March 23, 2007. The original four year PBR agreement, following a Negotiated Settlement Process, approved by the British Columbia Utilities Commission (the "Commission" or "BCUC") pursuant to Order No. G-51-03, dated July 29, 2003. For the purposes of this Application, the original four year PBR agreement and the two year extended PBR agreement will collectively

Period.[17] The efficiencies achieved during the PBR Period have translated into a lower starting point, on a per customer basis, for O&M forecasts in 2010 (inflation adjusted) than was the case in 2003. Thus, although the total gross O&M expenses are forecast to increase modestly from the level included in the 2009 projection, the per customer O&M costs in both 2010 and 2011, after adjusting for inflation, are actually lower than those that formed the basis for the 2003 Decision. See Appendix B-4 for a details of TGI's Key Operating Facts 2003-2009.

The requested rate increases for 2010 and 2011 are being driven by the significant changes taking place in TGI's external operating environment. The single largest contributor to the requested rate increase, for instance, is accounting changes associated with the adoption of new accounting standards applicable to TGI. But for the accounting changes, the revenue requirement would have indicated a rate decrease for 2010 and a small increase for 2011.

TGI recognizes, however, that the changing environment involves much more than changes in accounting standards. It extends to evolving needs of customers and communities, the effect of changing economic times for our customers, and government policy impacts. We must invest in our core business and enhance our ability to provide comprehensive energy solutions for customers.

1. Performance Based Rate Agreements and the Traditional Revenue Requirement Model

The PBR Agreement, encompassing the original settlement agreement and the two-year extension, has served customers and the Company well. TGI also believes its reputation as a respected and trusted operator has been solidified during the past six years under the PBR Agreement. TGI explored the possibility of a further extension of the current PBR Agreement prior to filing this Application. However, after receiving input from parties to the settlement, TGI ultimately concluded that a return to a traditional regulatory model for the 2010 and 2011 period would be the most effective regulatory construct.

With respect to the two-year scope of this Application, there are three main reasons why a two-year RRA is appropriate at this time. These reasons are:

- The change to IFRS will cover a two year period and a two year RRA provides a stable base over which IFRS can be implemented. Any unforeseen impacts of IFRS can then be dealt with

be referred to as the "PBR Agreement". Additionally, throughout this Application the six year period commencing January 1, 2004 and ending December 31, 2009 will be referred to as the "PBR Period".

[17] See Appendix B-3 for a copy of Regulatory History

comprehensively in 2012. The adoption of IFRS is the single largest driver of the requested rate increases in 2010 and 2011.

- The two-year RRA is consistent with the timeline being considered for a potential amalgamation of the three Terasen Utilities, driven by the elimination of the Royalty Revenues for TGVI at the end of 2011.
- The timing is consistent with the implementation of the Company's proposed Customer Care Enhancement Project, as outlined in the application filed with the Commission on June 2, 2009.

The Company is hopeful that the outcome of this RRA will provide the basis for further discussion about a subsequent multi-year PBR plan. PBR plans could, in the future, provide the means to continue to promote further alignment of interests between customers and the Company. Any prospective PBR plans must be grounded in the external reality facing the Company at that time. It must account for our need to respond to the evolving expectations of customers, government policy developments, safety and reliability obligations, accounting standards, and the need to invest in human resources. All of these factors affect our ability to serve our customers.

2. Organization of this Application

TGI has endeavoured to present a comprehensive filing and has included a significant amount of historical data and contextual information with the objectives of ensuring transparency and increasing the efficiency of the regulatory review process. We are hopeful that our inclusion of this information with the Application will reduce the need for information requests intended to obtain data, and allow all parties to focus on the matters considered to be of greatest significance.

The remaining sections of this Application are:

A. The External Situational Context
B. Terasen Gas as the Respected and Trusted Operator
C. Continued Investments in Base Business and New Energy Solutions
D. The Approvals Sought with this Application
E. Appendices Overview

A series of appendices are also provided as outlined in Section E.

The content of each of these sections is summarized briefly below.

a) The External Situational Context

TGI determined forecast demand and costs for the RRA with reference to a number of external factors, described in Part III, Section A, External Situational Context. We must account for these factors in this Application to ensure that our business is able to evolve to reflect changing circumstances. The Application identifies the following five external realities:

1. *Evolving Energy Policy:* Energy policy at all levels of government is increasingly focused on addressing climate change and energy conservation. This policy, while laudable, represents a challenge to TGI's core business of providing natural gas service which must be addressed. It also represents an opportunity on which TGI can capitalize with the right investments and regulatory constructs in place. The new service offerings discussed in this Application, for example, represent a response to the challenges and opportunities presented by government policy.

2. *Evolving Expectations:* Expectations of customers, regulators, and other stakeholders are evolving. There is a growing interest among customers in reducing consumption and finding alternative energy options. Communities are becoming engaged in energy planning. There is increased regulatory attention on particular aspects of safety and security. Terasen Gas will have to take action to continue meeting their respective needs. Investment in EEC programs; investment in our ability to provide safe, reliable and cost-effective gas service; and, investment in new service offerings, are appropriate responses to changing expectations.

3. *Competitive Position:* Despite improvements in its pricing relative to other energy commodities, the rise in absolute gas prices as compared to embedded electricity costs in B.C. and how customer rates are set for natural gas and electricity continues to create a competitive challenge for TGI. This affects our ability to attract new customers, and also affects the energy consumption patterns of existing customers. This, in turn, affects delivery rates.

4. *Economic Conditions:* The recent economic downturn has impacted our customers, which in turn affects delivery rates for customers. Lower housing starts, for instance, lead to fewer customer attachments, lower overall consumption both of which affects delivery rates.

5. *Changing Accounting Standards:* Accounting standards and related guidance are in flux. The changes in accounting policies do not change the amount of total costs to be recovered from ratepayers, but changing standards do affect the timing of when those costs may be recovered. It is expected that rates will rise in the short term, but this initial increase will be offset by lower

rates in the future related to this development. Accounting changes associated with the adoption of IFRS are the single greatest contributor to the requested delivery rate increases in 2010 and 2011.

We are committed to meeting the challenges presented by these external realities. We also recognize that the situational context presents opportunities. Our response to the external realities is discussed in the remaining sections of the Application.

b) Terasen Gas as the Respected and Trusted Operator

TGI takes pride in the fact that it has long been recognized as a respected and trusted operator, providing safe, reliable and cost effective utility service to customers. Our reputation as a respected and trusted operator is tied to our strong performance in five key areas:

1. Company's Corporate Governance Structure and Management Processes and Controls;
2. Delivery of Customer Service and Delivery Rates paid by our Customers;
3. Operational Performance;
4. Employee Impacts; and
5. Financial Results, for the benefit of customers and our shareholder.

Since 2004, both the customers and shareholders of Terasen Gas have benefited from our current PBR Agreement. During this time, service quality levels have generally been met, customer satisfaction levels have increased and customer delivery rates have remained essentially flat. Our success in responding to the challenges faced during the PBR Period has strengthened our reputation as a respected and trusted operator in the communities in which we serve. Our performance during the PBR Period is detailed in Part III, Section B, Tab 1.

Maintaining our reputation will require a decisive response to the new challenges and opportunities facing the Company. Below, we outline how Terasen Gas will respond in each of these five key areas. This is discussed in detail in Part III, Section B, Tab 2.

1. Terasen Gas Intends to Continue to Pursue Excellence in Management and Enhance Governance Structures

Terasen Gas must continue to invest in the controls and management constructs (including IT Systems) that will ensure that TGI continues to meet and exceed corporate governance and regulatory requirements while enabling us to serve the growing needs of our customers and communities. This includes:

- increasing our efforts to improve safety measures;
- taking the necessary steps to ensure an appropriate level of security for TGI's physical assets (pipes, stations and buildings) and soft assets (computer systems and infrastructure); and
- being fully prepared to respond to business interruption, regardless of the event.

2. We Intend to Meet the Evolving Expectations of Customers and Communities We Serve Through the Delivery of Quality Service

It is critical to meet the long-term interests of our customers that we enhance our focus on efforts aimed at maintaining and improving customer service and satisfaction. This must occur not only in the core natural gas business but also across a broader suite of services and offerings directed at meeting the evolving needs of our customers and communities.

- TGI must invest in improving the quality of our customer care activities while bridging to an orderly transition for implementation of the Customer Care Enhancement Project. The details are described in Part III, Section C, Tab 6.
- Terasen Gas is committed to pursuing cost effective EEC measures. This Application includes a proposal to extend investment in previously-approved program areas into 2011. We propose to re-allocate approved EEC funds to programs directed at low income customers and rental housing. We also propose to expand the existing EEC portfolio and spending for programs directed at industrial customers and new technologies. The details of the proposal are described in Part III, Section C, Tab 3 of the Application.
- At the same time, TGI will complement our core natural gas business with alternative energy solutions. As set out in Section Part III, Section C, Tab 3, the Company proposes a regulatory model to allow Terasen Gas to pursue opportunities in each of the following areas: Biogas, Liquified Natural Gas ("LNG") and Compressed Natural Gas ("CNG") for transportation; solar thermal; and geothermal and District Heating. The model includes specific economic tests, similar in nature to the Company's Main Extension Test. The application of these tests will ensure that the cost of providing service to the prospective customers will not unduly impact existing customers.

3. Continued Focus on Operational Performance and Operational Excellence into the Future

TGI must invest to maintain Operational Excellence.

- The Company has exhausted opportunities for significant incremental efficiency gains under the existing PBR framework. The current PBR Agreement has an efficiency factor equal to two-thirds of inflation, an implicit productivity improvement that is not sustainable, especially when labour inflation is higher than inflation rates.

- Expenditures that were pragmatically deferred during the PBR Period cannot be deferred indefinitely and some will need to be made in the 2010/2011 forecast period. TGI must continue to invest in the integrity and reliability of the energy delivery system. To ensure ongoing compliance to existing codes and anticipated new or changed codes, additional O&M funding is required.
- Terasen Gas will continue to act as a responsible corporate citizen, having regard for the environmental impacts of our activities in the communities in which we do business.

4. Terasen Gas needs to increase its efforts in the Retention, Attraction and Development of its Employees

As a prudent operator, TGI must invest in the people who deliver service to our customers: our employees. Notwithstanding the recent economic downturn, the Company is entering a critical stage in a labour market that is challenged on two fronts by an aging workforce and a limited supply of younger, skilled workers graduating from trades and technology programs. TGI needs to invest in strengthening the foundation of its end-to-end Talent Management systems and processes to remain competitive and continue to grow its business.

5. Future Financial Results Continue to Provide for Efficiencies and Benefits to Customers

As we emerge from six years of PBR Agreement, the overall picture is a favourable one with respect to the management of our controllable costs. Customers have obtained a permanent benefit of significant savings during the PBR Period through prudent management. We will continue to seek opportunities for efficiency in our operations for the benefit of customers.

c) Continued Investments in Base Business and New Energy Solutions

Part III, Section C of the Application, titled Continued Investments in Base Business and New Energy Solutions, translates the response identified in The Future into initiatives for the 2010 and 2011 forecast periods. Many of these initiatives have been referred to and described in The Future section summarized above. Most importantly, TGI believes that it must continue to invest in areas such as management excellence, customer service, operational performance, and our employees. The proposed rates for 2010 and 2011 will allow that to occur in a manner that will benefit customers and the Company going forward.

The Continued Investments in Base Business and New Energy Solutions section is organized into 13 different tabbed sub-sections:

1. Introduction
2. Revenue Requirement and Rate Proposals
3. Energy Efficiency and Conservation Expenditures and Alternative Energy Solutions
4. Gas Sales and Transportation Demand
5. Cost of Gas
6. Operating and Maintenance Expenses
7. Taxes
8. Rate Base
9. Capital Expenditures
10. Capital Structure and Earned Return
11. Accounting Changes and Other Policies
12. Tariff Changes
13. Financial Schedules

Included in these 13 sub-sections is an explanation of the rate increase and service offerings that the Company is proposing.

d) Approvals Sought and Proposed Regulatory Process

Part III, Section D of the Application specifies the various requests for which we are seeking Commission approval. We also set out a proposed regulatory process and timeline for the review of this Application. The Company has developed this proposed process and timeline in consideration of the other significant rate applications Terasen Gas and its sister companies currently have before the Commission and those expected to be brought forward in the near future and the resulting impacts on interested parties. As described more fully in Part III, Section D, TGI believes that a written hearing would be appropriate due to three factors: (1) the major drivers of the rate increases are external or "exogenous" factors; (2) on a per customer basis, O&M expenses are lower than those in the 2003 Decision after accounting for inflation; and (3) the depth of information provided in this Application. The Company's objective of its proposed regulatory process and timetable is a more efficient review and approval process for all parties concerned.

Summary

Terasen Gas has a long history of providing a reliable supply of natural gas to communities throughout British Columbia. We have a history of doing so safely, efficiently and at a reasonable cost. We are committed to continuing to do so for years to come. Customers have obtained considerable benefits from the PBR Agreement, and those benefits have been consolidated through the rebasing in this Application. The proposals included in this Application reflect our commitment to invest in, and maintain our proven track record. The forecasted costs that underpin our delivery rate proposals are prudent and required to meet the evolving needs of our customers, stakeholders and shareholder.

III. APPLICATION

A. External Situational Context

Over the next 20 years the province of B.C.'s population is expected to grow by more than 25 per cent or over 1 million people.[18] Demand for all types of energy is expected to increase – even as the pressure to improve energy conservation and efficiency measures intensifies. Terasen Gas is committed to being part of the solution in providing this energy. To do so, the Company must ensure its business evolves along with the world in which it operates.

The forecasted costs identified in this Application reflect our careful consideration of what steps are required to meet the changing needs of TGI customers, the communities the Company serves and its shareholder. They reflect consideration of external factors such as Terasen Gas' level of competitiveness, B.C.'s evolving provincial energy and environmental policies, changing economic realities and more. Overall, these developments present increasing challenges to the Company's natural gas business, but also present an opportunity for the provision of other energy solutions to our customers.

In this section of the Application we suggest there are five material external realities that must be considered when reviewing the requests made later in this Application. These external factors are:

1. **Energy policy at all levels of government is increasingly focused on addressing climate change and energy conservation, and TGI business must evolve to support this focus.** This section will explore how B.C. Government Policy, Municipal Government Policy, and Federal Government Policy are all aggressively encouraging the reduction of GHGs, have a focus on lowering energy consumption, and are keen in their search for and developing alternative (and renewable) energy sources. The implications of these policies for Terasen Gas are important and will be outlined in the Application.

2. **Expectations of Customers, Regulators, and Other Stakeholders are evolving, and Terasen Gas will have to take action to continue meeting their respective needs.** Within this section we discuss what customers expect from Terasen Gas related to customer care and meeting their energy needs. Customers' energy needs are changing with concerns about GHG emissions and energy efficiency, as such customers are looking at reducing consumption, finding alternative energy options and communities are becoming engaged in energy planning. This section will also discuss how the public

[18] See Appendix C-1 for a copy of BC Stats, BC Population Forecast

is increasingly concerned about public safety and security. These issues are addressed by looking at how regulators are mandating that Terasen Gas change to meet new codes and regulations.

3. **Terasen Gas' competitive position continues to decline relative to its peers and competitors.** In this section of the Application, Terasen Gas will outline how natural gas market prices have improved relative to other energy commodities (such as oil) in the North America marketplace, but faces challenges in the B.C. marketplace due to the differing nature of how natural gas and electricity costs are set into customer rates. This poses challenges, to which we must respond. This competitive challenge is not only an economic one, but is also related to customers' changing perceptions about how the use of natural gas contributes to climate change.

4. **BC Economic Outlook and Demographic Challenges.** In this section of the application Terasen Gas explores the economic outlook for B.C. in the coming years and the issue of changing demographics in the workforce. These topics have implications for Terasen Gas and its customers.

5. **Accounting standards and related guidance are in Flux.** Canadian accounting standards are now entering a time of unprecedented change. Canadian utilities will be required to comply with IFRS for financial reporting periods commencing on or after January 1, 2011, with comparative figures for 2010 restated to be in compliance with IFRS. This section discusses these recent changes and its future impact on setting delivery rates to Terasen Gas customers.

Together these external realities help to provide some context to Terasen Gas business opportunities and challenges in meeting its role as being a trusted energy provider to customers in the province of B.C. in the coming years. These topics are discussed in more detail below.

On May 15, 2009, the Terasen Utilities filed an ROE Application seeking to correct the ROE mechanism and, for Terasen Gas, seeking to increase the equity component of its capital structure, so as to provide Terasen Gas with an opportunity to earn a fair return on its investment. The ROE Application or any resulting impacts on the Company's revenue requirements and rate proposals is not discussed in this RRA. However, following a decision on the ROE Application, the proposed rates in this Application will have to be adjusted to reflect the results of the ROE Application decision. It should be recognized that the outcome of that proceeding affects the financial health of Terasen Gas. Ultimately, this has an impact on our customers.

1. Energy Policy at all Levels of Government is Increasingly Focused on Addressing Climate Change and Energy Conservation, and the Terasen Gas Business Must Evolve to Support this Focus

In recent years B.C.'s provincial government and municipalities have taken steps to develop targets and action plans to support the reduction in GHG emissions. The actions of Canada's federal government, while not (yet) reflected in formal policy, reinforce this focus on cutting GHG emissions while reducing consumption of carbon based fuels. With the recent changes in the federal government of the United States, there is a renewed commitment to clean energy and GHG reduction.[19] Thus, all levels of government across North America recognize that GHG reduction is a pressing reality.

Climate change and energy consumption are subjects of enormous importance to British Columbians today and into the future. The public has accepted that GHGs contribute to climate change and that action must be taken. TGI supports sustainability initiatives through its Energy and Efficiency Conservation programs and in its own operations. There is nevertheless an important role for natural gas in the long-term sustainability picture due to the advantages inherent in its physical properties, i.e. lowest emissions of the fossil fuels, no/low particulate matter, etc. Consumers also want clean air and affordable comfort, in addition to carbon reductions, all of which are areas where natural gas provides benefits. Natural gas will continue to be the right choice for the majority of consumers, and its use should be encouraged where it is the right energy form for the right application at the right time given its relative stage of commercial and technological development. Using natural gas in more applications can serve to reduce GHG emissions and more. When fuel alternatives exist it is imperative that the appropriate rates and incentive mechanisms, as well as consistent messaging, are in place to encourage the efficient use of energy through market-based approaches. In this way, carbon reduction may be enhanced through energy choice.

Elsewhere in North America, where energy needs are frequently met through burning coal or refined petroleum products, natural gas is recognized as a clean alternative. In British Columbia, by contrast, there is an abundance of renewable sources of hydro-electric generation. TGI must overcome the perception that hydroelectricity is always the right energy source, and that natural gas should be displaced by electricity for traditional applications such as space and water heating and other direct use applications. There are better solutions than using electricity alone which result in lower net emissions

[19] On May 15, 2009 U.S. House Energy and Commerce Committee Chairman Henry Waxman and House Energy and Environment Subcommittee Chairman Edward Markey introduced H.R. 2454, The American Clean Energy and Security Act ("ACESA"), which calls for an economy-wide GHG cap and trade system and other complementary GHG reduction measures.

and reduced energy use by continuously seeking to use each energy form to its highest and best value across interconnected energy grids regardless of geographic borders.

Terasen Gas is committed to being part of the solution by ensuring customers have access to the energy they need while also promoting Energy Efficiency and Conservation. Terasen Gas also recognizes that these laudable objectives and goals represent challenges to the Company's traditional natural gas business. It is thus important for Terasen Gas to undertake and explore new initiatives that support government policy while at the same time helping our customers find energy solutions that meet their changing needs. In fact, energy policy calls upon utilities to play an integral role in doing this very thing.[20] There are opportunities for the use of other non-traditional energy sources, both in conjunction with natural gas and on their own. There are opportunities for TGI to be a provider of energy solutions beyond just gas. Indeed, TGI considers it to be vital that we become a provider of diverse energy solutions for customers. The steps TGI is taking to meet this challenge and capture this opportunity are discussed later in this Application.

This increased challenge to Terasen Gas becomes self-evident when considering the following:

a) Provincial policy is focused on achieving GHG reductions and Energy Conservation.
b) Municipal policy is supporting provincial policy through commitment to the British Columbia Climate Action Charter.
c) Federal policy reflects a commitment to reduction in the rate of global warming.

This section will expand on these three points, while also explaining the implications to Terasen Gas.

a) Provincial policy is focused on achieving GHG reductions and Energy Conservation

The B.C. Provincial Government's energy and climate change policies will shape how energy is used by consumers within B.C. now and into the future. While the use of natural gas in the right application at the right time is goal-congruent with GHG reductions, the current statement of policy and related regulation has not matured to the level which sufficiently clarifies this point. Instead, the current state of evolution of policy initiatives, while ostensibly neutral as to energy choice, has the unintended consequence of discouraging the use of natural gas without particular regard to its benefits in certain end use applications. For instance, historic embedded cost of generation based electricity in rates

[20] For example, BC Energy Plan: A Vision for Clean Energy Leadership, Policy #3 (Encourage utilities to pursue cost effective and competitive demand side management opportunities) and Policy #4 (Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation) are policies objectives that give direction to the roles that utilities need to play.

versus market priced natural gas in rates, government mandated cross-subsidization of BC Hydro residential customers by other BC Hydro customer segments, and postage stamp tolling methodology for electricity in the province compared to distance related rates for natural gas, all send messages to the consumer that do not favour gas even where gas may be the right energy source for a particular application. In addition, provincial policies address GHG emissions on a provincial, rather than a regional basis. GHGs are a regional issue given that GHGs do not abide by political boundaries given the existence of interconnected energy grids. Examining GHGs on a provincial basis ignores the potential for gas consumption in efficient direct use applications in BC in order to reduce GHG emissions elsewhere in the region.

We expect that over time, policy clarification and regulation will serve to reduce this negative tension between some provincial policies and the overarching global goal of reducing the impacts of climate change. Nevertheless, these policies have significant repercussions for Terasen Gas' existing and future business.

The B.C. government's focus on reducing GHGs is reflected in a wide range of key initiatives and undertakings in recent years. These include:

- British Columbia - Energy Plan 2007: A Vision For Clean Energy Leadership
- 2007 Greenhouse Gas Reduction Targets Act
- B.C.'s Revenue – Neutral Carbon Tax and Emission Offset Regulation
- 2008 Amendments to the Utilities Commission Act
- Climate Action Plan
- Climate Action Team Report
- Province of British Columbia Strategic Plan 2009/2010-2011/2012
- Future Regulation (Western Climate Initiative)

Together these will shape the demand for energy by consumers in B.C., and thus impact how this energy is provided and delivered. Each is explained in more detail below.

(1) BRITISH COLUMBIA - ENERGY PLAN 2007: A VISION FOR CLEAN ENERGY LEADERSHIP[21]

On February 27, 2007 the B.C. government released a new Energy Plan: A Vision for Clean Energy Leadership. The Energy Plan indicated that the world had focused its attention on the critical issue of global warming, the British Columbia government decided to demonstrate the province's commitment to the production of clean energy and reduction of GHG emissions in the province, by leveraging the

[21] See Appendix C-2 for a copy of Energy Plan 2007: A Vision for Clean Energy Leadership, p. 3

province's key natural strengths and competitive advantages involving clean and renewable sources of energy.[22]

The Energy Plan of 2007 builds on the successes of the 2002 Energy Plan: Energy for Our Future: A Plan for BC. The Energy Plan 2002 had the following policy cornerstones:

- Low electricity rates to be assured by entrenching the benefits of publicly owned assets, independently regulating British Columbia Hydro and Power Authority ("BC Hydro") rates and outsourcing services where economic.
- To promote secure and dependable energy, reliability standards would be maintained, new supplies were to be developed and the Commission would be strengthened.
- To increase opportunities for the private sector, independent power was to be developed and ongoing support provided for the oil and gas industry.
- Environmental responsibility was to be assured through a clean energy goal, new price signals for conservation, clear emission standards and other strategies. [23]

Another policy item that was laid out in the Energy Plan of 2002 was *"natural gas marketers will be free to sell directly to residential and small commercial natural gas customers"*.[24] This specific policy item led to the establishment of the Terasen Gas Commercial Unbundling Program in April 2004 and ultimately to the Terasen Gas Customer Choice Program for residential customers, which started on May 1, 2007. See Part III, Section B, Tab 1 for more details on TGI Unbundling Program. The design and the implementation of the Unbundling Program is an example of how Terasen Gas plays a leadership role in moving government policy forward.

The Energy Plan of 2007 continues to build on the policies that were outlined in the Energy Plan of 2002. The Energy Plan of 2007 has the following goals and objectives, each of which present challenges and opportunities for Terasen Gas.[25]

a) *Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.*

22 See Appendix C-2 for a copy of Energy Plan 2007: A Vision for Clean Energy Leadership
23 See Appendix C-3 for a copy of Energy Plan 2002: Energy for Our Future: A Plan for BC, page 12
24 See Appendix C-3 for a copy of Energy Plan 2002: Energy for Our Future: A Plan for BC, page 9
25 See Appendix C-2 for a copy of Energy Plan 2007: A Vision for Clean Energy Leadership

The B.C. Government set a goal to reduce the growth in electricity demand so that by 2020, 10,000 gigawatt-hour ("GWh") of currently forecast needs would be met through demand reduction measures. This includes energy efficiency, conservation, and other demand-side solutions.

b) Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.

The Government is to ensure that all parties that help to deliver programs and initiatives to consumers have a coordinated approach.

c) Encourage utilities to pursue cost effective and competitive demand side management opportunities.

Under this Energy Plan, utilities in B.C. are to pursue all cost effective investments in demand-side management ("DSM"). Utilities are also encouraged to develop a diversified portfolio of programs to ensure all ratepayers can benefit from these programs. In particular, program development should consider how to make DSM programs accessible to residential ratepayers across all income levels.

d) Explore with BC utilities new rate structures that encourage energy efficiency and conservation.

All utilities are asked to explore, develop and propose to the Commission additional innovative rate designs that encourage efficiency, conservation and the development of clean or renewable energy. These include stepped rates for other rate classes, interruptible/curtailable rates, critical period rates, clean electricity supply rates, tariffs focused on promoting energy efficient new construction and others. Part of this work includes consideration of the benefits of 'smart' or advanced metering technology.

e) Implement Energy Efficiency Standards for Buildings by 2010.

To achieve energy conservation, government is determined to work with industry, local governments and other stakeholders to prepare and implement cost effective energy efficiency standards for buildings. Provincial energy efficiency building standards are needed to achieve energy efficiency and conservation targets and to support the goal of self-sufficiency, including commitments under BC Hydro's current Integrated Electricity Plan.

f) All new electricity generating facilities constructed in British Columbia will have net zero greenhouse gas emissions.

The B.C. government's objective is to effectively use the province's rich energy resources such as hydro electricity, natural gas and coal, preserving B.C.'s environmental standards, while upholding the province's quality of life for generations to come. The government made a commitment that all new electricity generation projects developed in British Columbia and connected to the grid would have zero net GHG emissions. In addition, any new electricity generated from coal must meet the more stringent standard of zero GHG emissions.

g) *By 2016, existing thermal generating power plants will achieve zero net greenhouse gas emissions.*

For existing plants, the government will set policy around reaching zero net emissions by 2016 through carbon offsets. It clearly signals the government's intention to continue to have one of the lowest GHG emission electricity sectors in the world.

h) *Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.*

The BC Energy Plan for 2007 commits to maintaining clean or renewable electricity generation contributing 90 per cent of total generation which places the province among the top jurisdictions in the world. Clean or renewable resources include water power, solar energy, wind energy, tidal energy, geothermal energy, wood residue energy, and energy from organic municipal waste.

i) *Ensure self-sufficiency to meet electricity needs by 2016, plus "insurance" power to supply unexpected demand thereafter*

The government notes that achieving electricity self-sufficiency is fundamental to B.C.'s future energy security and will allow the province to achieve a reliable, clean and affordable supply of electricity. In this regard the government committed that British Columbia will be electricity self-sufficient by 2016 and appropriate measures will be taken to ensure BC Hydro achieves this goal.

j) *New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.*

To achieve the goal of reducing GHG emissions the Climate Action Team was to define a number of *"indicators of integrated environmental design"* (i.e. greenhouse gas, energy, water, building materials and transportation footprint). The indicators would be calculated on a regular basis by conducting audits of all existing, publicly funded buildings of a minimum size, and for all new construction projects. The audits to be completed prior to 2010 will be used to establish new integrated environmental design standards that will apply to all buildings that receive new funds from the Province.

k) Increase participation in the Community Action on Energy Efficiency program and expand the First Nations and Remote Community Clean Energy program.

The Energy Plan for 2007 intends to increase provincial government partnership with local governments to encourage energy conservation at the community level through the Community Action on Energy Efficiency Program and the expanded First Nations and Remote Community Clean Energy program. This will involve promoting energy efficiency and community energy planning projects, and providing direct policy and technical support to local governments through a partnership with the Fraser Basin Council.

The Energy Plan for 2007 sets ambitious targets and also sets out a strategy for reducing the province's GHG emissions and a commitment to unprecedented investments in alternative energy technology.

As the 2007 Energy Plan states:

> *"It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar thermal and geothermal. Working with municipalities, utilities, and other stakeholders the provincial government will promote energy efficiency and alternative energy systems, such as solar thermal and geothermal throughout the province."*[26]

These policies are commendable, as they emphasize energy efficiency and conservation, and an integrated approach in finding energy solutions to reduce GHG emissions, objectives which TGI supports.

Yet these policies have also had the effect of putting Terasen Gas' traditional natural gas business at risk if Terasen Gas was to take a "do nothing approach". Without taking action, TGI could see a continued

[26] See Appendix C-2 for a copy of Energy Plan 2007: A Vision for Clean Energy Leadership, page 21

decline in total throughput volume flowing in the Terasen Gas natural gas distribution system. Over the long term, a decrease in throughput volume leads to higher unit delivery costs, which make natural gas more costly for customers, all else equal, and which would result in sub-optimal net GHG and other emissions.

(2) 2007 GREENHOUSE GAS REDUCTION TARGETS ACT ("GGRTA")

As part of the B.C. Throne Speech delivered on February 13, 2007, the government first announced targets for provincial GHG reductions.[27] The GGRTA put into law the most aggressive GHG emission reduction targets in North America effective January 1, 2008. The targets set by the GGRTA are as follows:

- To reduce B.C. greenhouse gas emissions by 33 per cent of 2007 level by 2020.
- By 2050 and for each subsequent calendar year, B.C. greenhouse gas emissions to be at least 80 per cent less than the level of those emissions in 2007.
- The provincial government, including all its departments, to become carbon neutral by 2010.
- By December 31, 2008, the minister must, by order, establish B.C. greenhouse gas emissions targets for 2012 and 2016. [28]

On November 25, 2008 further GHG interim targets were set by Ministerial Order as follows:

- 2012 – six per cent below 2007; and
- 2016 – eighteen per cent 2007 levels.

(3) B.C.'S REVENUE- NEUTRAL CARBON TAX AND EMISSION OFFSET REGULATIONS

The B.C. government was the first in North America to introduce a consumer–based carbon tax effective July 1, 2008. The tax encourages individuals and businesses to make more environmentally responsible choices; thus, incenting reduced use of fossil fuels and related emissions.[29]

The carbon tax applies on the purchase of fossil fuels in British Columbia, such as gasoline, diesel, natural gas, heating fuel, propane and coal. The tax starts at $10/tonne of CO2e and will reach $30/tonne of CO2e by 2012 by which time natural gas consumers in B.C. will be paying a $1.50 per gigajoule ("GJ") in carbon tax. It is projected that the tax will contribute revenues to the Province, of

[27] See Appendix C-4 for a copy of Speech from the Throne 2007
[28] See Appendix C-5 for a copy of Bill 44 - 2007 Greenhouse Gas Reduction Targets Act
[29] See Appendix C-6 for a New Tax Cuts for British Columbians Beginning July 1

about $1.85 billion over the first three years.[30] The carbon tax gives customers in British Columbia a choice on how they wish to adapt their behaviour to reduce their consumption of fossil fuels and is expected to help the government of B.C. achieve about 7.5 per cent of the government's legislated reductions by 2020.[31]

The province's further commitment to GHG reduction was reinforced when the B.C. government enacted the Emission Offsets Regulation in December 2008. These offset regulations were enacted to address the quality of GHG offsets in British Columbia in terms of the GGRTA.

The emission offset regulation sets out requirements for GHG reductions and removals from projects or actions to be recognized as emission offsets for the purposes of fulfilling the provincial government's commitment to carbon-neutral public sector by 2010.

The GGRTA helps to ensure that the GHG emission reduction targets are met. The detailed guidance document to the regulation is being prepared by the Ministry of Environment for publication in 2009.

Together the provincial reduction targets, the carbon tax and the emission offsets regulation present new challenges for Terasen Gas. The emissions from natural gas consumption within B.C. count against the GHG reduction target, while natural gas' primary competitive energy alternative – electricity – is deemed to be clean and therefore accounts for virtually no GHG emissions in B.C vis a vis the target. These regulations result in further competitive challenges for TGI and therefore impact the customers of TGI.

How these regulations will work with the Western Climate Initiative ("WCI") cap and trade system is still yet to be determined by government in the coming year.[32] Harmonization with federal regulation is also yet to be determined. Further details on the WCI follow in this section.

(4) 2008 AMENDMENTS TO THE UTILITIES COMMISSION ACT

To demonstrate the province's renewed focus on energy conservation and climate change and to empower the Commission to ensure utilities undertake efficiency and conservation measures in their

30 See Appendix C-7 for a copy of B.C. introduces carbon tax, p. 2

31 See Appendix C-7 for a copy of B.C. introduces carbon tax, p. 2

32 BC Hydro, Final Argument 2008 LTAP, dated April 9, 2009, pages 44-45 states: Pursuant to section 84 of the Carbon Tax Act, the B.C. Cabinet may with respect to a car fuel or combustible that is the source of the GHG emissions, provide for a regulation that exempts from the payment of the tax, or refunds all or part of the tax paid, subject to compliance obligations under the Carbon Tax Act and the new offset requirement for electricity generation under the Emissions Standards Act.

operations, the B.C. government in 2008 enacted amendments to the Act to reflect the following "government's energy objectives":

- to encourage public utilities to reduce greenhouse gas emissions;
- to encourage public utilities to take demand-side measures;
- to encourage public utilities to produce, generate and acquire electricity from clean or renewable sources;
- to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility;
- to encourage public utilities to use innovative energy technologies; and
- to encourage public utilities to take prescribed actions in support of any other goals prescribed by regulation. [33]

The Commission is required to consider government's energy objectives in the context of long-term plans, applications for a Certificate of Public Convenience and Necessity ("CPCN") and applications for approval of expenditure schedules. The amendments clearly positioned utilities as being on the front lines of implementing policies that encourage energy efficiency and the reduction of GHGs.

Further regulation that is administered by the BCUC relates to Demand-Side Measures Regulation.[34] These regulations were modified by ministerial Order No. 271 on November 6, 2008. Key changes to the regulation are:

- A public utility's plan portfolio is adequate for the purposes of the Act only if the plan portfolio includes all of the following:
    - A demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption; and
    - If the plan portfolio is submitted on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations.

The Province had previously removed a significant barrier to utilities pursuing cost-effective demand-side management by introducing the 2003 amendments to the Act in which a revised Section 60 (1) (b) included the provision that the Commission must have due regard in setting a rate that the public utility is provided, *"a fair and reasonable return on any expenditure made by it to reduce energy demands*".

[33] See Appendix C-8 for a copy of Bill 15 – 2008 Utilities Commission Amendment Act
[34] See Appendix C-9 for a copy of Demand-Side Measures Regulation

This change removed a potential financial disincentive for utilities to make expenditures to reduce energy consumption over investments in system expansion to accommodate load growth.

These amendments further reinforced that utilities such as Terasen Gas should take a leading role in implementing policies that encourage energy efficiency and the reduction of GHGs. See Part III, Section C, Tab 3 for details relating to TGI's response to these new DSM regulations.

(5) CLIMATE ACTION PLAN

Both the 2007 Energy Plan and the more recently released Climate Action Plan[35] demonstrate the B.C. Government vision and resolve for B.C. to tackle climate changes and in doing so, change the way British Columbian's think and act with respect to energy usage. As an example, the message from the government in the Climate Action Plan states:

> *"Global warming is the challenge of our generation. How we respond will shape the future of not just our environment, but also our economy, our society, our communities, and our way of life. British Columbia is taking decisive action to ensure these changes are positive. Since 2007 we have built a solid framework that addresses climate action in four key ways:*
>
> - *We have entrenched greenhouse gas reduction in law, including a commitment to reduce B.C. emissions by one-third by 2020.*
> - *We are taking targeted action in all sectors of the B.C. economy to help reduce emissions and set the course for the new low-carbon economy of the future.*
> - *We are taking steps to help British Columbians adapt to the realities of climate change and its impact on the province.*
> - *We are beginning a process to educate and engage British Columbians. This includes holding public forms and developing our LiveSmart BC initiative to support individuals, families, communities, business and industry to make cleaner choices and help.*
>
> *We are making good progress. In fact, independent economic modeling estimates that the climate action initiatives we have already announced will take us approximately 73 per cent of the way to our 33 per cent 2020 reduction target".*[36]

The Climate Action Plan maintains a consistent message from the provincial government about the commitment it has to reduction of GHGs and mitigation of climate change. As the summary of the Climate Action Plan suggests, *"we are taking action in all sectors of the BC economy to help reduce*

[35] See Appendix C-10 for a copy of Climate Action Plan

[36] See Appendix C-10 for a copy of Climate Action Plan, page 1

emissions". Given that about 15 per cent of B.C. GHG emissions come from the direct consumption of natural gas by customers, there can be no doubt that these policies will have a meaningful impact on Terasen Gas' natural gas business.[37] The prudent approach is for Terasen Gas to take proactive steps to address the impact of these policies. Please see Part III, Section C, Tab 3 for Terasen Gas responses to these policies.

(6) CLIMATE ACTION TEAM REPORT

To help the Province reach its goals relating to GHG, the British Columbia's Climate Action Team ("CAT") was established in November 2007.[38] On July 28, 2008, a report entitled: "Meeting British Columbia's Targets", was released by the CAT. In this report the CAT outlines 31 recommendations that could be taken to help the Province reach its GHG reduction targets. The specific policy recommendations that could have a direct impact to Terasen Gas and its customers are:

- Increase the British Columbia tax after 2012 if required to achieve the emission targets, in a manner that aligns with the policies of other jurisdictions and key economic factors.
- Develop, in collaboration with public and private partners, a comprehensive, multidimensional public engagement and outreach campaign that will: 1) educate British Columbians about the importance of climate change and the policies that are necessary to address this issue and 2) help British Columbians reduce their own greenhouse gas emissions in the most efficient way possible, and 3) make British Columbian's aware of the incentives and savings available by taking action on climate change.
- Update B.C.'s Green Building Code at least every three years to ensure B.C.'s code is a leader among North American energy codes.
- Require that, by 2016, all new publicly-funded buildings in the province have net-zero GHG emissions and that by 2020 all new houses and building have net-zero GHG emission.
- Introduce an aggressive energy efficiency and renewable energy program for houses and buildings, combining incentives and regulatory approaches and coordinated across governments and utilities.

All of the above recommendations have the intent of reducing fossil fuel use within homes and business, which by their very nature impact Terasen Gas by shaping customers' behavior regarding energy use.

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[37] In 2006, TGI customers consumed 210,150,414 GJ's which converts into 10.507 million tonnes of GHG or about 15% of the 69 million tonnes of GHG produces in BC .

[38] See Appendix C-11 for a copy of Climate Action Team Report, page 2

An example of how these recommendations and other provincial policy objectives can influence customers' choices around energy consumption comes in the form of the University of British Columbia ("UBC") issuing a request for proposal to explore alternative energies at UBC. According to the public information provided by UBC, UBC Utilities produce steam currently on campus with four natural gas fed steam boilers. Two of the four steam boilers are scheduled to be replaced in the next seven years and UBC Utilities is aggressively looking to alternative non-polluting technologies to heat campus and ancillary tenant buildings.[39] One of the reasons behind why UBC is exploring this avenue is to support the objective to ensure carbon neutrality in all provincial public sector operations.

Thus, the CAT recommendations and government policies seem to be influencing and shaping purchasing decision of customers that were historically natural gas customers, and prompting them to consider alternate choices.

(7) PROVINCE OF BRITISH COLUMBIA STRATEGIC PLAN 2009/10 – 2011/12

In February, 2009, the Province of B.C. released its "Strategic Plan 2009/10 – 2011/12". This plan continues B.C.'s strong commitment as a "champion for climate change".[40] The plan goes on to say: *"B.C. has charted its course on climate change, with the establishment of its legislated goals for carbon emissions and greenhouse gas emissions. Our strategies developed over the last few years outline our plans and targets on everything from energy, bio-energy, agriculture, mountain pine beetle, to water, air, transit, and construction. Over the coming years, we will be focusing our efforts on implementing these strategies in order to achieve our objectives."*[41]

(8) FUTURE REGULATION

Energy and environmental policies are evolving and B.C. is taking the lead in setting standards. British Columbia has set ambitious emission reduction targets with the intention of transforming B.C. to a 'green energy' economy.

Like other responsible corporate citizens, Terasen Gas must continually review and evolve its environmental governance efforts in order to remain compliant with changing legislation, regulatory requirements, and government initiatives. Some of the challenges Terasen Gas must prepare for relate to future carbon emissions regulation are set out below.

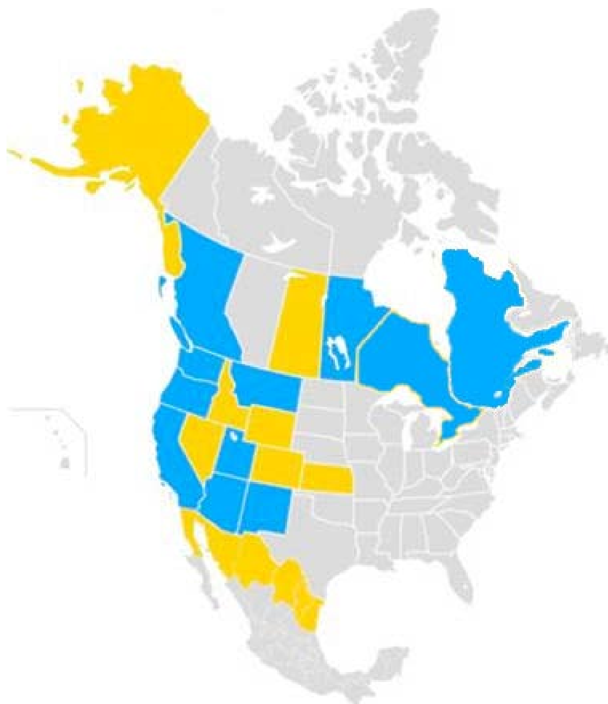
[39] See Appendix C-12 for a copy of UBC Utilities Alternative Energy Project
[40] See Appendix C-13 for a copy of Province of British Columbia Strategic Plan, page 1
[41] See Appendix C-13 for a copy of Province of British Columbia Strategic Plan, page 38

(a) Incoming Legislation: Western Climate Initiative

British Columbia joined the WCI in 2007. The WCI is a partnership between seven U.S. states and four Canadian provinces (See Figure A-1, below).

Figure A-1: Province of B.C. Joins the WCI from its Inception

Western Climate Initiative Region



Yellow = Observer; Blue = Partner

WCI members have agreed to develop, among other things, a common framework for reporting and reducing GHG emissions. The region has committed to an overall emission reduction of 15 per cent below 2005 levels by 2020.

A substantial component of achieving this goal will occur through the development of a cap and trade system. Cap-and-trade functions by setting an overall limit on emissions for a region or economy the "cap". WCI Partners' caps will be determined based on individual targets, such that the limit for captured industries in 2020 will relate to a specific number of emitted tonnes.

Once the cap is set, each jurisdiction is provided an 'allowance budget', such that each 'allowance' represents one tonne of GHG emissions. While the specific details of how these allowances are obtained by captured sectors have yet to be determined, the eventual goal is that a declining number of allowances are available over time.

Each captured facility must obtain allowances for every tonne of their own emissions. Allowances are traded at market values such that those facilities that reduce beyond their regulated target are able to sell allowances at market rates. This ensures that the lowest cost emission reductions are achieved across the economy.

WCI reporting rules will require submission of a detailed, auditable emissions inventory starting with the 2010 calendar year. Terasen Gas understands that B.C.'s own Reporting Regulation under the Greenhouse Gas Reduction (Cap and Trade) Act will require reporting for the 2009 calendar year.

Development and management of inventories that will meet the stringent auditing requirements of a cap and trade system will require sophisticated software, owing to the scope of the Terasen Gas inventory and the level of transparency that will be necessary. This has been confirmed by previous voluntary audits of Terasen Gas GHG inventories.

Cap and trade, which will begin on January 1, 2012, will measure combustion, vented and fugitive emissions from nearly all of Terasen Gas' facilities. Compliance with B.C.'s aggressive targets will involve substantial strategic development around carbon management, and will require involvement in the cap and trade carbon market.

WCI, as well as the Waxman-Markey cap and trade bill at the US federal level, propose to make local distribution companies ("LDCs") the point of regulation for smaller customers (i.e. residential, commercial and industrial emitters below the regulatory threshold) under cap and trade. Under this model, LDCs will be responsible for purchasing allowances on behalf of their customers. How these cap and trade models work with the B.C. carbon tax will be determined in the coming years.

(9) CONCLUSION: PROVINCIAL POLICY FOCUSED ON REDUCING GHGS AND LEADING TO NEW CHALLENGES FOR TGI

The province of British Columbia is providing leadership by setting the course around developing targets and action plans to reduce GHG emissions so that others can follow.

TGI acknowledges that the public has accepted that GHG emissions contribute to climate change and that action must be taken. Terasen Gas is also committed to being part of the solution by helping customers have access to the energy they need while simultaneously meeting the province's legislative objectives and goals. Yet it is also clear that these policies present challenges to Terasen Gas' existing business, which could translate into increased costs for Terasen Gas customers if left unchecked. It is important for Terasen Gas to undertake and explore new initiatives that support government policy but at the same time help our customers find energy solutions that meet their changing needs.

In October, 2008 a report by the Canadian Gas Association ("CGA"), working in conjunction with Terasen Gas and Pacific Northern Gas, "A Vision for British Columbia's Energy Future: Smart Gas Strategies"[42], described three approaches, which build upon each other to improve the energy system. These three approaches are:

- Use available energy efficiently.
- Introduce alternative energy options.
- Move towards integrated community energy solutions.

Terasen Gas supports this logic path to reducing GHG emissions, while accommodating ongoing gross domestic product ("GDP") and population growth in B.C.

In response to these polices and realities, TGI has brought forth new energy alternatives for customers to help them and therefore the province of B.C. meet its energy objectives and goals. See Part III, Section C, Tab 3 for more details on new customer energy solution offerings.

Provincial energy and environmental policies are further supported by actions at the Municipal Government level. This is discussed in the next section.

b) Municipal Government Policy Also Committed to Provincial Energy Goals

Not only has the province of B.C. shown leadership in establishing energy and climate change objectives, local governments within B.C. are supporting these objectives by committing to the British Columbia Climate Action Charter.

(1) BRITISH COLUMBIA CLIMATE ACTION CHARTER

To commit B.C. Communities to the goal of attaining carbon neutrality by 2012, the Province, local governments and the Union of B.C. Municipalities ("UBCM") from across the province of B.C., signed a Climate Action Charter (the "Charter") on September 26, 2007.43 This charter committed local

[42] See Appendix C-14 for a copy of A Vision for British Columbia's Energy Future: Smart Gas Strategies
[43] See Appendix C-15 for a copy of British Columbia Climate Action Charter

governments to measuring and reporting their community's GHG emissions profile and to create more compact energy efficient communities. The provincial government realized that working in partnership with local governments would be more effective in reducing GHGs. Sixty-two communities initially signed the Charter and more signatures were expected to follow.[44]

To support the climate change initiatives, UBCM and the provincial government have *"established a Joint provincial-UBCM Green Communities committee and Green Communities Working groups to define a range of actions that can effect climate change, build local government capacity to plan and implement climate change initiatives, support local government in taking actions to make their own operations carbon neutral by 2012 and share information to support climate change initiatives"*.[45]

By March 31, 2009, as government efforts to fight climate change intensified, 174 local governments had signed the British Columbia Climate Action Charter demonstrating the importance and seriousness government attached to the issue of climate change throughout the province. The Charter should also result in the creation of economic benefits in the communities.[46]

This agreement and commitment by both provincial and local government is consistent with past messaging from organizations as such Metro Vancouver (formerly Greater Vancouver Regional District). For instance, the Air Quality Management Plan for Metro Vancouver, titled "Clean Air, Breathe Easy", dated September 2005 states on page 1:

> *"Actions that reduce emissions of common air contaminants and increase energy efficiency will be the most sustainable. Greater reliance on renewable energy sources and technologies with low or no emissions will directly benefit public health, the environment, tourism and agriculture."*

The policies pursued by municipal governments further encourage energy consumers to reduce their use of fossil fuels, including natural gas, or to consider alternatives entirely. These objectives and goals present challenges to Terasen Gas' traditional business.

c) Federal Government Policy Direction

Canada's Federal Government is committed to fight the growing global warming reality. The federal government has concluded that energy use and supply have made the greatest impact on the

[44] See Appendix C-16 for a copy of B.C. Communities Commit to Carbon Neutrality, p. 1
[45] See Appendix C-16 for a copy of B.C. Communities Commit to Carbon Neutrality, p. 1
[46] See Appendix C-17 for a copy of List of Local Governments who have signed B.C. Climate Action Charter

environment of any human activity, particularly regarding global warming, and has committed it to take action to reduce the rate at which global warming is taking place.

To achieve this, the federal government has put in place policies and objectives that, while not currently accompanied by legally binding targets, are nevertheless a strong indication that they are committed to the above goal.

The Federal government has outlined the following goals and objectives in recent years:

- Climate Change Plan 2005 – Moving Forward on Climate Change: "A Plan for Honouring Our Kyoto Commitment".
- Climate Action Plan 2007: "Turning The Corner".
- Speech From the Throne: To Protect Canada's Future.

Theses are discussed in more detail below.

(1) CLIMATE CHANGE PLAN 2005 - MOVING FORWARD ON CLIMATE CHANGE: "A PLAN FOR HONOURING OUR KYOTO COMMITMENT"

As a step towards the implementation of the Kyoto Protocol, after Canada's ratification in November 2002, the federal government on April 12, 2005 released a new national Climate Change Plan entitled 'Moving Forward on Climate Change; A Plan for Honouring our Kyoto Commitment'. The plan combined regulatory, negotiated and incentive based measures to reduce GHG emissions and its key elements include the following:

a) The large Final Emitters System. This was a mandatory market driven program aimed at reducing greenhouse gas emissions by 45 megatonne ("Mt") in mining, manufacturing, oil, gas and thermal electricity, which account for about half of national emissions.
b) Auto Sector. The auto manufacturers agreed in a Memorandum of Understanding with government to reduce CO2, methane, nitrous oxide, and hydroflourocarbon emissions from light duty passenger cars and trucks by 5.3 Mt or 6 per cent below business-as-usual by 2010.
c) Climate Fund. The government intends to purchase 75-115 Mt of reduction credits a year, up to 40 per cent of the total reduction needed in 2008-2012 through a new Climate Fund. Priority was to be given to domestic reductions from farmers, forestry companies, municipalities, and other sources. The government agreed to allocate CAD$1 billion per year over the next 5 years and projects funding of $4 billion-$5 billion for the 2008-2012.

d) Partnership Fund. A new Partnership Fund was set up to support government-to-government agreements at the federal, provincial, and territorial levels to jointly pursue emission reduction projects, including short and long-term climate change technology investments and infrastructure development. The government agreed to allocate CAD$50 million per year for the next five years and anticipated that funding of CAD$2 billion-$3 billion could result in 55-85 Mt annual reductions in 2008-2012.

e) The Wind Power Production Incentive was quadrupled to provide CAD$200 million over the first five years to produce a projected 4,000 megawatt (“MW”) increase in wind generating capacity. The Renewable Power Production Incentive was to provide CAD$97 million over five years to increase capacity from small hydroelectric, biomass, tidal, and other renewable sources by a projected 1,000 MW. [47]

This plan demonstrated the federal government’s commitment to work closely with provinces, territories, the industry sector, and other stakeholders to preserve and protect the environment from the effects of GHG emissions and air pollutants to establish a green economy.

(2) CLIMATE ACTION PLAN 2007: “TURNING THE CORNER”

To show its commitment to drastically reduce GHG emissions and air pollution, the Federal government on April 26, 2007 released an action plan called “Turning the Comer”. The plan puts in place one of the toughest regulatory regimes in the world which are as follows:

- To reduce GHG emissions by 20 per cent by 2020 to the 2006 levels and
- To reduce GHG emissions by 70 per cent by 2050 to 2006 levels. [48]

The targets for industrial greenhouse gas emissions are as follows:

Existing facilities

- 18 per cent reduction from 2006 emission intensity [49]starting in 2010
- 2 per cent annual improvement thereafter

New facilities

- 3-year grace period
- Clean fuel standard and

[47] See Appendix C-18 for a copy of Canada’s Climate Change Plan
[48] See Appendix C-19 for a copy of Climate Change Plan 2007
[49] Emission intensity is defined as a ratio of greenhouse gas emissions per unit of economic activity (GDP or unit of production such as barrel of oil).

- 2 per cent annual improvement

To ensure successful implementation the government introduced mandatory and enforceable actions across a broad range of sectors. The emission intensity approach ties the emission targets to production. This is a plan which recognizes the need to reduce GHG emissions while growing the economy.

(3) SPEECH FROM THE THRONE: TO PROTECT CANADA'S FUTURE

The speech from the throne "*To Protect Canada's Future*" delivered on November 19, 2008, reinforced the federal government's commitment to the provision of secure energy supply and fighting the challenges of climate change among other objectives.[50] It sets the direction provinces, local governments and communities are to take in the development of energy resources in an environmentally responsible manner.

The following measures are to be taken by the federal government in support of this commitment.

a) Support the development of cleaner energy sources. The development of natural gas reserves that lie beneath Canada's North was to be encouraged by reducing regulatory and other barriers to extend the pipeline network to the North. This is expected to bring jobs to northern Canada and create employment across the country.
b) Support the establishment of nuclear energy, should provinces choose to advance new nuclear plants.
c) Commit to reducing greenhouse gas emissions by 20 per cent below 2006 levels by 2020 while ensuring that Canada's actions are comparable to what United States, Europe and other industrialized countries undertake.
d) Set as an objective that 90 per cent of Canada's electricity needs should be provided by non emitting sources such as hydro, nuclear, clean coal or wind power by 2020.
e) Ensure protection of vital resources by legislating to ban water transfers or exports from Canadian fresh water basins.[51]

The foregoing recognizes the important role the federal government expects energy to play in the development of Canada going forward. The federal government is committed to use the country's rich and diverse energy resources such that they meet today and future generation's needs. The speech demonstrates the federal government's commitment to the provision of secure energy resources while

[50] See Appendix C-20 for a copy of Speech from the Throne 2008
[51] Ibid

tackling climate change issues to ensure business in Canada is carried out in an environmentally compliant manner and jobs are created for the benefit of the communities.

To advance the goal of reducing GHG emissions by 20 per cent from 2006 levels by 2020 the government of Canada on April 1, 2009 announced its intention to take action on each of the major sources of greenhouse gas emissions starting with the transportation sector, the biggest source of GHG emissions in the country. For the transportation sector, the government is to put in place regulations effective 2011 requiring that new passenger cars and trucks must be fuel efficient and should produce lower GHG emissions.[52]

Further, in a recent speech date June 4, 2009, made by Honourable Jim Prentice, Minister of the Environment stated the following related to climate change: "December is where the UN Climate Change process really crystallizes in Copenhagen, and Canada's goal is to be there to help secure a new global agreement on how we will move past Kyoto and deal with climate change. Copenhagen is effectively where the world will turn the page on Kyoto and look beyond 2012. It is our greatest hope that we will be successful in achieving an international consensus there to respond to what is increasingly recognized as the greatest environmental challenge of our time".[53]

(4) CONCLUSION

The federal government has demonstrated its commitment to fight against global warming by setting energy and environment polices which, although not legally binding, indicate the direction in which the federal government wants to move.

d) Summary of Implications Related to Energy Policy from All Levels Government for Terasen Gas' Business

The past several years British Columbia's provincial and municipal governments have sent a strong and repeated message through policy about their commitment to cutting GHG emissions, the main contributor to climate change. The federal government, while not tied to any binding legislation, has also signaled its intention to pursue these same goals through policy.

The desired outcome behind all of the policy initiatives is to reduce impacts of climate change and therefore, Terasen Gas is of the view that it is reasonable that the policy environment will mature over time. This maturation of policy should serve to ensure that the actions of British Columbians continually

52 See Appendix C-21 for a copy of Government of Canada to reduce greenhouse gas emissions from vehicles
53 Environment Canada – Media Room – 2009 Speeches Archives

migrate towards contributing to climate change goals without causing them economic disadvantage as compared to consumers in other regions. Terasen Gas is also of the view that provincial policy will also harmonize with those of federal and other governments in our region.

Terasen Gas agrees that action must be taken to address the climate change challenges we all face. TGI is also committed to being part of the solution by helping customers have access to the energy they need while simultaneously meeting the province's legislative objectives and goals. Terasen Gas also recognizes that, while laudable, these objectives and goals present challenges to Terasen Gas' traditional business. The result of these policies is that some members of the public and some policymakers in the province believe that the use of natural gas should be discouraged because its use results in GHG emissions.

A more nuanced consideration of the issues is required. There are applications for which gas is ideally suited, and gas is a clean alternative to other fossil fuels. The efficient consumption of natural gas in BC can result in GHG reductions elsewhere in the region. A complete energy picture involves using each energy form to its highest and best value across interconnected energy grids regardless of geographic borders. Integrating renewables with gas and electricity in variations which best fit a multitude of unique applications will help customers and communities respond to policy initiatives and public sentiment.

The new emphasis on climate change presents both obligations and opportunities for Terasen Gas to be a leader in assisting our customers to address these challenges. This Application also outlines a number of new initiatives that are aimed at providing customers with a range of energy solutions that are consistent with evolving government policy and public perception. The intended evolution of our business will protect the interests of our customers and our shareholder from consequences resulting from the rigorous pursuit of GHG policies that have not yet reached maturity. See Part III, Section C, Tab 3 for further details.

2. Expectations of Customers, Regulators and Stakeholders are Evolving, and Terasen Gas will have to take Action to Continue Meeting their Respective Needs.

The challenges presented to our traditional natural gas business by the current state of provincial, municipal and federal policy, on their own suggest that we should re-examine our business needs to ensure our long-term ability to meet the needs of energy consumers. The changing expectations and requirements that customers, stakeholders and regulators have of Terasen Gas makes a focused response even more imperative.

The discussion in the following section focuses on what customers expect from Terasen Gas related to customer care and meeting their energy needs. Meeting the energy needs of our customers crosses a broad spectrum ranging from the needs of an individual customer at a residential home to those of a community that is looking for an integrated energy solution. This section will also discuss how the public is increasingly concerned about public safety and security. These issues are addressed by looking at how regulators are mandating that Terasen Gas change to meet new codes and regulations.

This section reviews the following areas:

a) Evolving Community Involvement in Energy Choices
b) Growing Need for Increased Customer Care Activities
c) Increasing Public Concern about Safety and Security
d) Continuing Complexities in Aboriginal Rights

Terasen Gas is committed to meeting the needs of its customers and stakeholders. Yet if we are to do so then our business must take appropriate actions. Below these areas are discussed in detail.

a) Evolving Community Involvement in Energy Choices

Traditionally, end use customers simply purchased a new or used house without any concern or thought as to how the energy was delivered to the building. Gas and electrical energy were the common options. Customers were primarily concerned with the ongoing cost of energy. They thought little about the energy delivery system or whether or not the production of energy contributed to climate change. Energy was produced on a macro scale in large scale electrical generation facilities and natural gas production fields and then transported to end use customers.

This attitude is now changing in notable and significant ways. While many customers still do not have an interest in energy complexities, more and more are showing an interest in where energy comes from and how it is consumed. When broader policy targets enter the mix, as was previously described, communities have also started to become involved in decisions on how their own constituents use energy. This is impacting how Terasen Gas pursues its business and how it serves its customers.

Communities are now developing their own sustainability plans, which include:

- Looking at how the region should use energy;
- Looking at how they can influence the use of energy in their jurisdiction; and
- Looking at how they can influence development, through bylaws, planning regulations, and community consultation that will impact building codes.

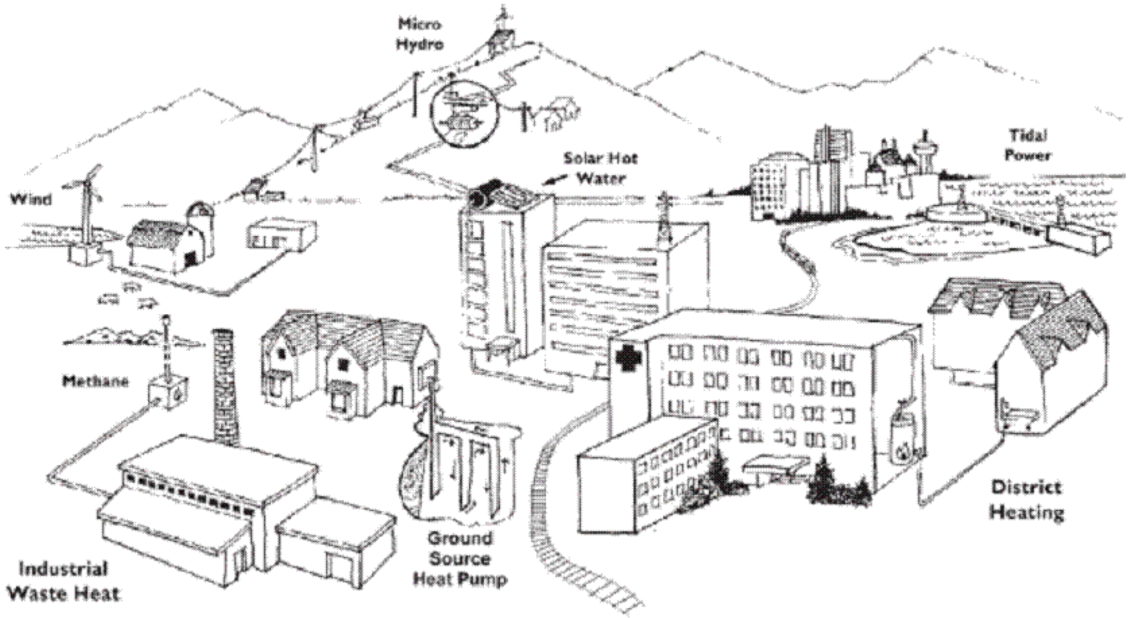
At the forefront of this change is Quality Urban Energy Systems of Tomorrow ("QUEST"). This group, a consortium of municipalities, provincial and federal governments, utilities and private industry, supported by stakeholders such as the Canada Green Building Council, Canadian Electricity Association, Canadian Energy Efficiency Alliance, CGA, Industry Canada, Natural Resources Canada, Ontario Power Authority, and Pollution Probe. [54] This consortium has been working together to promote an integrated approach for energy services in Canadian communities. QUEST White Paper I states that:

> *"The community, with its use of energy in houses, business, institutions, industry and transportation, is the most promising place to act.*
>
> *An integrated approach at that level allows balancing energy demand and supply between different sectors, accounting for the impact of one system versus the other, and leads to optimal results in providing community services.*
>
> *Integration of energy systems at the community level brings the maximum economic, social and environmental benefits".*[55]

In the QUEST community, all energy forms are integrated and interact with each other. This is demonstrated by the following figure.[56]

[54] Specifically Terasen Gas Inc., BC Hydro, and the Government of British Columbia participate in QUEST initiatives.
[55] See Appendix C-22 for a copy of QUEST White Paper I
[56] Ibid

Figure A-2: All Energy Forms Interact in a QUEST Community



Source: Green Municipalities - A Guide to Green Infrastructure for Canadian Municipalities; prepared for the FCM by the Sheltair Group, May 2001

For Terasen Gas to continue to participate and be successful in delivering energy in British Columbia, we must be involved in community energy planning and have the requisite resources to participate in a meaningful fashion. In addition, we must also be able to provide expertise about energy solutions that include not only natural gas but also alternative energy solutions and how best to integrate them.

Lastly, the majority of B.C. municipalities have committed to the provincial government to become carbon neutral by 2012.[57] In turn, this obligation has and will be making its way into local bylaws and thus changing the way developers must plan for energy requirements. Local governments have long been important partners for Terasen Gas, but they have now become even more crucial to the long-run success of the Company. By using a community, or QUEST approach, utilities can play a significant role in both developing community energy systems to meet customer needs and reduce the impact of climate change. Terasen Gas will need to play an important role in assisting communities and developers in understanding facts as well as identifying solutions. It is in the customer's best interest for Terasen Gas to be delivering these solutions given our broad geographic footprint, skilled workforce, knowledge and experience. Our customers' best interests are served by Terasen Gas being - and being

[57] See Appendix C-15 for a copy of British Columbia Climate Action Charter

perceived by municipalities and communities as - a provider of solutions for natural gas and/or alternative energy delivery.

b) Growing Need for Increased Customer Care Activities

The customer care function of Terasen Gas is a vital part of providing service to our customers, and consequently represents a core element of our business. It is the main point of interaction between customers and the Company in all aspects of our business. In order for the Company to continue to serve customers well, the customer care function needs to adapt and change as customers require new and different services. Underpinning this ability to provide service excellence is a technology platform.

A key emerging area of customer interest is energy conservation supported by more accurate and timely information related to energy consumption. Residential customers are interested in better understanding their home energy use and using that knowledge to manage their consumption and subsequent billing. This, combined with customer awareness related to their contribution to the carbon footprint, and specific initiatives particularly for government and institutional customers has resulted in demands for more timely and accurate information.

Further changes to our business requirements are expected over the next few years. In particular, Terasen Gas anticipates designing and developing new programs specifically targeting energy efficiency and conservation. This will require not only enhanced billing and tracking capabilities but also a highly knowledgeable workforce to support customer inquiries. In response to customer demand for enhanced billing and payment options Terasen Gas also requires technology changes to support these demands in a timely and cost effective manner.

In order to address these needs Terasen Gas, on June 2, 2009 applied to the BCUC for a CPCN for the Customer Care Enhancement Project. It contemplates the insourcing of core aspects of customer care services and the implementation of a new customer information system for January 1, 2012.

c) Increasing Public Concern about Safety and Security

Across North America, concerns regarding the reliability and safety of public infrastructure are growing. People are more aware of environmental and security issues, in addition to the aging of existing infrastructure. Public concern and expectations have increased pressure on regulators and code associations to enact increasingly stringent requirements. The specific codes discussed below govern the present and future operating requirements of the Company, with a strong focus on public, employee, property and environmental safety as well as system reliability. While compliance with safety regulations is the minimum performance standard expected to be achieved, Terasen Gas is committed to meeting the increasing safety expectations of the public by ensuring that programs and systems meet or, where appropriate, exceed regulatory requirements.

(1) B.C. OIL AND GAS COMMISSION ACT, B.C. PIPELINE ACT AND REGULATIONS (UNDERGOING CHANGE)

The Oil and Gas Activities Act will replace the Pipeline Act and the Oil and Gas Commission Act. The Oil and Gas Activities Act consolidates the powers and duties of the Oil and Gas Commission ("OGC") as well as the rules regulating persons carrying out an oil and gas activity in the province. It is unknown at this time what operating changes will be required by Terasen Gas when this Oil and Gas Activities Act is finalized.

(2) CANADIAN STANDARD'S ASSOCIATION ("CSA") CSA Z662 – OIL AND GAS PIPELINE SYSTEMS

CSA Z662 is the CSA standard for oil and gas pipeline systems. It defines minimum requirements throughout the lifecycle of transmission and distribution gas system assets including design, installation, and operations.

Integrity Management activities have been part of CSA Z662 since its inception. The goal of integrity management of gas distribution systems and pipelines is to provide safe, environmentally responsible and reliable service with focus on mitigating and managing the potential for external interference, failure and damage incidents. These incidents may result in an immediate unplanned release of gas or cause damage to a pipe, component or coating which increases the likelihood of an unplanned release in the future. Many of the clauses within CSA Z662 relate to designing, installing and maintaining plant to provide safe and reliable service.

Major incidents across North America, such as the 1999 Olympic Pipeline rupture due to pressure in Bellingham, Washington and the 2007 Kinder Morgan Canada oil pipeline rupture due to third party damage in Burnaby, B.C., have put safety concerns into the forefront of the minds of the public and regulators. Stakeholder groups want to ensure that asset integrity is at the highest reasonable standard including: robust processes and system and record keeping that is highly transparent. As a result, in Canada, the CSA has added Annex M & N to CSA Z662.

Annex M provides a framework for Distribution Systems Integrity Management Plans, but as of yet is not mandatory. Annex N introduces the requirement for a formal IMP for Pipeline Systems, which was formally adopted by the OGC as a requirement on August 26, 2006. Terasen Gas performed the majority of the items within the Annexes, and developed and implemented its formal IMP using these base activities and augmenting where appropriate. The resulting IMP covers all gas system assets, as required by Annex M and N.

The 2007 version of CSA Z662 also introduced Clause 10.2 Safety and Loss Management Systems as a mandatory requirement of the code and provides Annex A as an applicable template. Annex A sets out a recommended practice for a safety and loss management system applicable to design, construction, operation, and maintenance activities that can affect the safety of people or the protection of property or the environment. Clause 10.2 also suggests that companies may require a period of two years or more to reach compliance. Terasen Gas is in the process of accessing potential compliance gaps to this new requirement. Samples of other safety and emergency codes that must link into Annex A requirements include provincial and federal Emergency Acts, Environment Management Act (see below), fire codes, and safety standards (see below).

(3) CSA Z276 - LIQUID NATURAL GAS PRODUCTION, STORAGE AND HANDLING

CSA Z276 is the CSA standard for liquid natural gas production, storage and handling. It defines standards which govern Terasen Gas' LNG Plant operations. No significant changes have been introduced into this code over the PBR Period and none are anticipated in the near future. The new Mt. Hayes facility is being constructed to meet CSA Z276 compliance.

(4) CSA Z246 - SECURITY MANAGEMENT FOR PETROLEUM AND NATURAL GAS INDUSTRY SYSTEMS (ANTICIPATED RELEASE OCTOBER 2009)

Emergency planning agencies consider critical infrastructure such as natural gas facilities prime targets for terrorists and, as such, the CSA has drafted a new standard: CSA Z246.1, Security Management for Petroleum and Natural Gas Industry Systems to formalize requirements.

Enactment of CSA Z246.1 will bring new requirements designed to improve natural gas facilities protection from vandals and terrorist activities.

(5) CSA Z1000 – SAFETY MANAGEMENT SYSTEM AND WORKSAFEBC

Recent high profile accident investigations in B.C. and subsequent court cases have found that management systems based on compliance only, are inadequate. Regulators and the courts in Canada and throughout the western world are looking at standards agencies such as British Standards ("BSI"), American National Standards Institute ("ANSI") and CSA to provide guidance on how effective a company's safety program is.

CSA Z1000 is the CSA standard for safety management. It defines a framework for a safety management system which would allow a company to reduce accidents and risks, meet compliance and legal requirements and build a solid defendable due diligence.

Upon investigating management systems, the Terasen Gas Occupational Health and Safety group has concluded that the CSA Z1000 standard meets the needs of Terasen Gas and the existing management system, which meets the strict compliance requirements as set by WorkSafeBC, and will be reshaped to meet this new standard through 2009/2010.

(6) BC SAFETY AUTHORITY ("BCSA"): SAFETY STANDARDS ACT AND GAS SAFETY REGULATIONS

The BCSA administers a number of safety programs to fulfill its mandate of "*overseeing the safety of key technology areas*".[58] Certain activities at Terasen Gas are governed by the BCSA – Gas Safety Regulation. "*The Gas Safety Program regulates safety in the area of gas distribution*"[59] and other gas related matters (i.e. propane gas).

The BCSA change to the Procedures for Excavations section of the Gas Safety Regulation significantly impacts the operations of Terasen Gas. Prior to April 1, 2008, a gas company was given 3 days to provide gas system information requested by a third party. On April 1, 2008, the regulation was changed to state that "*on receiving a request under subsection (2) a gas company must provide the information requested within 2 business days*".[60] As a result of this code change, TGI has had to increase staff members handling such requests in order to meet the 2 day requirement.

(7) POWER ENGINEERS, BOILER, PRESSURE VESSEL AND REFRIGERATION SAFETY REGULATION

Pressure vessels were previously considered part of the piping system. An improved understanding of this code requires that these pressure vessels be registered with the BC Pressure Vessels branch, data files to be set up and inspections carried on a periodic basis pursuant to the American Petroleum Institute ("API") standard API 510 and the safety authority. API 510 is the recognized North American standard that covers the in-service inspection, repair, alteration, and rerating activities for pressure vessels and the pressure-relieving devices protecting these vessels and is an appropriate base for establishing the required pressure vessel related work. Terasen Gas will be working towards compliance through the 2009-2010 period.

[58] See Appendix C-23 for a copy of BC Safety Authority - Safety Programs
[59] See Appendix C-24 for a copy of BC Safety Authority - Gas Safety Program
[60] See Appendix C-25 for a copy of Safety Standards Act - Gas Safety Regulation

(8) ENVIRONMENTAL MANAGEMENT ACT

British Columbia places a high value on ensuring environmentally sound practices as demonstrated by its Environmental Management Act. The Act includes significant penalties for non-compliance in terms of environmental management.

One example of how the new environmental rules impact Terasen Gas deals with the Federal Species at Risk Act. The number of species which require special consideration and protection when activities are planned in areas they inhabit has increased. In addition, fines and penalties for non-compliance have increased. Since Terasen Gas regularly excavates in the ground to install pipe and other facilities, new measures are required to be taken to effectively and efficiently screen project areas prior to construction for the potential to impact protected species.

(9) 3RD PARTY REQUESTS FOR UPGRADES

As government, community and other utilities respond to their own issues with aging infrastructure, Terasen Gas has faced increased pressure to upgrade its assets as a result of these external infrastructure projects. This will continue as the 2010 Olympic and Paralympic Winter Games near and as infrastructure projects emerge as stimulus measures to ease the current economic downturn. Much of the cost of these projects can be recovered by billing the requestor, but there are several factors that affect the degree of cost sharing. Additionally, Terasen Gas is not in control of the schedules for road projects, which places demands on internal resources to make the necessary adjustments.

(10) SUMMARY

The specific codes, discussed above, as well as local bylaws govern present and future operating requirements of the Company. Terasen Gas places a high priority on public, employee, property and environmental safety as well as system reliability, and strives to comply, or when appropriate exceed, codes requirements. As codes change, operating practices of the Company, in some cases, also needs to change. Part III, Section B, Tab 1, The Past, discusses how Terasen Gas has met compliance during the PBR Period and Part III, Section C, Tab 6, O&M, discusses Terasen Gas' operating changes to address the 2010/2011 compliance needs.

d) Continuing Complexities in Aboriginal Rights

Uncertainty as to the nature and extent of aboriginal rights and title in B.C. and the lack of treaties create operational and regulatory complexity for Terasen Gas that must be managed.

There are very few treaties in British Columbia. Historical treaties only cover a relatively small part of B.C. (portions of Vancouver Island and the northeast corner of the province). There have been treaty negotiations in recent years but only three treaties have been completed. Due to the small number of treaties in B.C., there are many unestablished claims for aboriginal rights or title. This leads to uncertainty both as to the scope of the rights, and the area in which it is exercised.

B.C. recognizes approximately 285 different First Nations, Bands and Tribal Councils. The need to recognize and deal with Tribal Councils flows from the lack of treaties, making it more difficult to identify the appropriate aboriginal representative. The high number of aboriginal groups in British Columbia leads to overlapping territories and competing claims for aboriginal title, as well as strong differences in opinion as to the appropriate forum for reconciling aboriginal rights and title. There is division among BC First Nations as to whether to enter the current treaty negotiation process. Since TGI's activities span large parts of British Columbia, the large number of different aboriginal groups whose interests may overlap requires careful management by TGI when pursuing projects.

TGI needs to invest in the necessary resources to address properly the issues presented by asserted claims of aboriginal rights and title and the duty to consult and, if necessary accommodate.

3. Terasen Gas' Competitive Position Continues to Decline Relative to its Peers and Competitors

Terasen Gas' competitive position relative to peers and competitors continues to decline, presenting further challenges that we must meet.

Historically, consumers have made purchase decisions about what energy supply source they are willing to buy based on a numbers of variables. Historical decision criteria includes the cost of product, ease of use, and reliability. In addition to these historical decision criteria, the provincial GHG reduction targets have the potential to adversely change people's perception of natural gas over the long term. The targets may shift investment and consumption decisions of the consumer away from natural gas towards the consumption of electricity or other renewable energy alternatives (such as solar and geothermal).

Thus, direct use of natural gas for certain applications must overcome two hurdles before the buyer will make a commitment to investing in natural gas equipment. One is the economic test, comparing the historical and future natural gas operating costs and capital cost versus the competitive alternative. The second hurdle that needs to be overcome is related to the "green" perception of a product and how that product helps in the climate change challenge.

The gradual erosion of natural gas' cost advantage in B.C. versus electricity impacts TGI's growth in new customer additions, and also impacts existing customers' throughput levels. Natural gas market prices have improved relative to other energy commodities (such as oil) in the North America marketplace, but natural gas faces challenges in the B.C. marketplace due to the differing nature of how natural gas and electricity costs are reflected in rates. Increases in natural gas prices incent customers to reduce their energy consumption or look for cheaper alternatives to meet their energy needs. Both cases lead to reduced consumption levels on the natural gas system which negatively impacts existing customer's rates, all else being equal.

The following areas illustrate this reality:

a) Historical cost advantage of natural gas is declining
b) TGI competitiveness to electricity versus other jurisdictions is in decline
c) Forward looking operating cost advantage of natural gas is likely to decline
d) Demand for perceived "green" energy represents an additional challenge

When looking at natural gas competiveness, we need to consider both the operating cost (cost of the energy) and the cost of installing the equipment (capital or upfront costs).

These points are discussed below.

a) Historical Operating Cost Advantage of Natural Gas is Declining

One of the continuing challenges facing TGI is the decline in price advantage against electricity (the difference between lower natural gas rates compared to electricity rates) on an annual operating cost basis. Between 1998 and 2008, the price advantage of natural gas compared to electricity in B.C. declined from 63 per cent to 18 per cent[61], and yet its relative competitiveness to petroleum based products improved and its use as a fuel source for power generation increased substantially.

Annual operating costs for natural gas applications such as space and water heating may improve versus using electrical alternatives for these applications in the coming years with the establishment of the BC Hydro Residential Inclining Block ("RIB") rate that was implemented October 1, 2008. The carbon tax will be an offsetting factor to this improvement. Natural gas must also maintain a significant annual

[61] Figures in Appendix C-26: Competitive Rae Comparisions History 1998-2009, show 2009 but 2009 is not reflected in this calculation as the year is not complete and gas commodity may changes in the remaining months for 2009.

operating cost advantage compared to electricity to provide a payback on the upfront equipment cost difference of a natural gas heated home and one that uses electricity baseboards for space heating.

As shown in Appendix C-26: Competitive Rate Comparisons History 1998-2009, natural gas enjoyed a substantial price advantage versus electricity in the late 1990's throughout the three TGI regions (Lower Mainland, Inland and Columbia). In all three regions, the cost of natural gas to a customer in 1998 was less than half the cost of using electricity for the same applications. This price advantage has gradually declined as natural gas rates increased with rising commodity costs while electricity rates remained relatively constant.

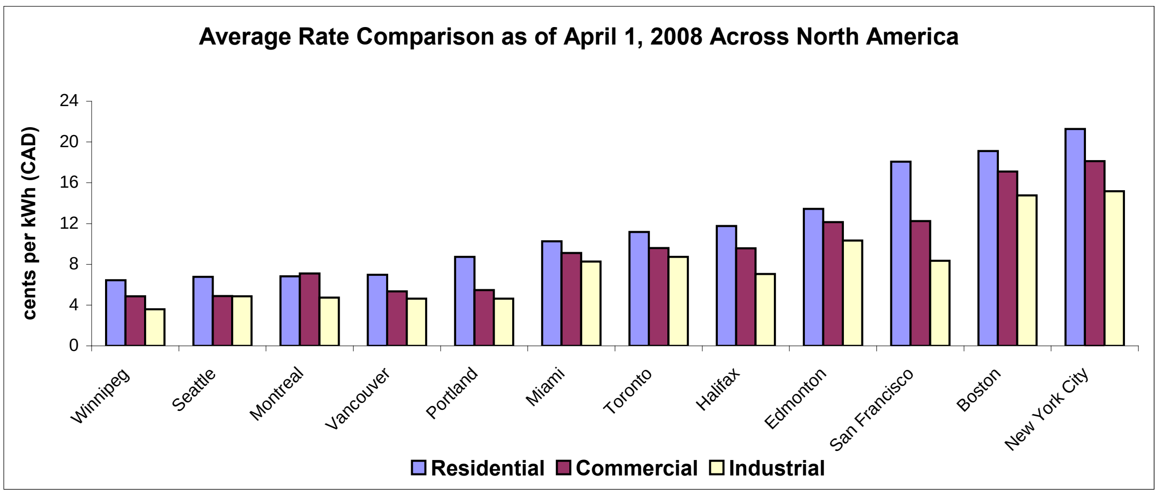
BC Hydro's electricity rates have remained relatively flat over this timeframe. Prior to 2004 BC Hydro was in an extended rate freeze period and was not subject to BCUC oversight. During the rate freeze period BC Hydro was able to absorb its cost pressures with decreasing costs in other categories such as declining interest rates and with profits from electricity exports. In the meantime electric load has continued to grow beyond the supply capabilities of BC Hydro's Heritage resources, necessitating the acquisition in recent years of new and more costly renewables. However, BC Hydro's rates are largely reflective of Heritage or historical costs of supply and continue to be among the lowest electricity rates in North America. With the establishment of the BC Hydro RIB rate, a customer's electricity rates will be determined based on the consumption level at the particular residential dwelling. In principle, the RIB represents a splitting of the allocated historical costs for the residential class into two rates, with the rate for the second step being higher, in order to promote energy conservation. Notwithstanding this design, the conservation impact is significantly dampened given the net revenue requirement quantum does not change, meaning that the RIB rate revenues serve to reduce the rate applying to the Step 1 rate.

The gradual erosion of the natural gas rate (not cost) advantage relative to electricity increases make throughput levels more challenging to achieve. Reduced consumption levels on the natural gas system negatively impacts exiting customer's rates, all else being equal.

The continued decline in the operating cost advantage from 63 per cent in 1998 to just 18 per cent in 2008 for natural gas versus electricity, its primary competition, combined with the lower capital and installation costs for electric baseboard heaters has created a challenging competitive market environment. The capital and installation costs for a new natural gas heating system typically range from three to four times higher than for electric baseboards. The difference in upfront capital cost for heating equipment and ducting makes the simple payback to the potential natural gas customer extend over a long period of time or exceed the expected life of that equipment.

One of the reasons for the decline in the price advantage that natural gas has had against electricity is how these products are priced in B.C. Natural gas commodity pricing for consumers in B.C. is market-based; in contrast a large percentage of the costs making up electricity rates are the low embedded costs of BC Hydro's Heritage generation facilities. Please see Figure A-3 below, which shows BC Hydro's electrical rates are among the lowest in North America.

Figure A-3: B.C. has Low Electricity Rates Compared to Most of North America



Rates are based on Hydro-Quebec's "Comparison of Electricity Prices in Major North American Cities"
Seattle rates are based on Seattle City Light

b) TGI Competitiveness to Electricity versus other Jurisdictions in Decline

TGI faces a higher level of price competition than many other gas distribution utilities in Canada and the Pacific Northwest. Figure A-4 below shows the natural gas versus electric price differential for TGI in the Lower Mainland and six other gas distribution companies, based on current residential customer rates. All companies who compete against market priced electricity enjoyed a price advantage ranging from approximately 2 per cent to 74 per cent as compared with a 32 per cent price differential for TGI. As Figure A-4 is taken at a specific point in time, the difference between rates among the companies will change over time.

Figure A-4: Comparison of Natural Gas versus Electric Price Advantage for Five Companies (2009)

	ANNUAL BILL - NATURAL GAS	ANNUAL BILL - ELECTRIC	GAS VS. ELECTRIC PRICE ADVANTAGE	
Terasen Gas (Lower Mainland)	$1,118	* $1,641	-32%	lower
Puget Sound Energy - Washington	$1,476	$2,530	-42%	lower
Northwest Natural Gas - Oregon	$1,604	$2,142	-25%	lower
Direct-Atco - Alberta	$775	$2,979	-74%	lower
Union Gas - Ontario	$1,010	$2,366	-57%	lower
Enbridge Gas - Ontario	$875	$2,366	-63%	lower
Gaz Metro - Quebec	$1,543	$1,574	-2%	lower

Notes:
**Calculated BC Hydro rate based on the F2009-2010 RRA approved increase of 8.74% (inclusive of the applicable 1% rate rider)*

Annual Bills for natural gas and electric, for all territories, are based on an annual use rate of 95 GJ.

The efficiency of gas equipment is assumed to be 90% relative to 100% for electricity to determine equivalent electricity. Lower gas efficiency appliances would result in lower gas price advantages than indicated above.

The annual electric rates do not include the fixed monthly charges since it is assumed that a household already pays the basic electric charge for non-heating use.

All rates are as at April 1, 2009.

All rates are exclusive of applicable franchise fees and/or taxes (with the exception of the Carbon Tax). Interior BC community customers pay a franchise fee of approximately 3%, which would reduce the indicated price advantage of gas by a like amount.

All annual bills are best estimates based on the information available from each utility.

c) Forward Looking Operating Cost Advantage of Natural Gas likely to Decline

The ability to remain competitive to the price of electricity has become increasingly difficult, particularly over the last few years with increased natural gas prices and price volatility as well as the recent and growing burden of the carbon tax.

Near-term economic realities have improved the competitiveness of natural gas. Market prices are currently depressed due to declining industrial demand, high storage balances and weaker crude oil prices.

Yet, it is long-term factors that will have a greater influence on prices and volatility in years ahead. Such factors suggest that the competitiveness of natural gas will continue to erode. These long-term factors include declining Western Canadian Sedimentary Basin natural gas production, higher finding and development costs, increasing demand for power and air conditioning produced from natural gas outside of B.C., and the potential for active hurricane seasons affecting the Gulf of Mexico producing region. Furthermore, future economic recovery and the associated increase in demand combined with the reduction in natural gas production forecasted in 2009 could add to future market price volatility and potentially higher gas prices. While the gap between forecasted electricity rates and the current natural gas forward curve has widened in the short term, this may well be short lived given the volatility in the North American energy markets and the fact that the actual costs of finding and developing new sources of natural gas exceeds current market prices.[62]

The following graphs (Figure A-5 and Figure A-6) illustrate the recent volatility in natural gas commodity prices compared to the commodity component of the electric equivalent.

[62] As of June 9, 2009 forward natural gas prices at Sumas are $2.90 US/MMbtu for July/2009 and $5.80 US/MMbtu for the winter 2009/2010. These prices are below the average well supply cost of northeast BC shale production which is $6.80 US/mcf .

Figure A-5: AECO[63] Prices vs. Electric Equivalent Commodity Component

Current Prices as of May 11, 2009

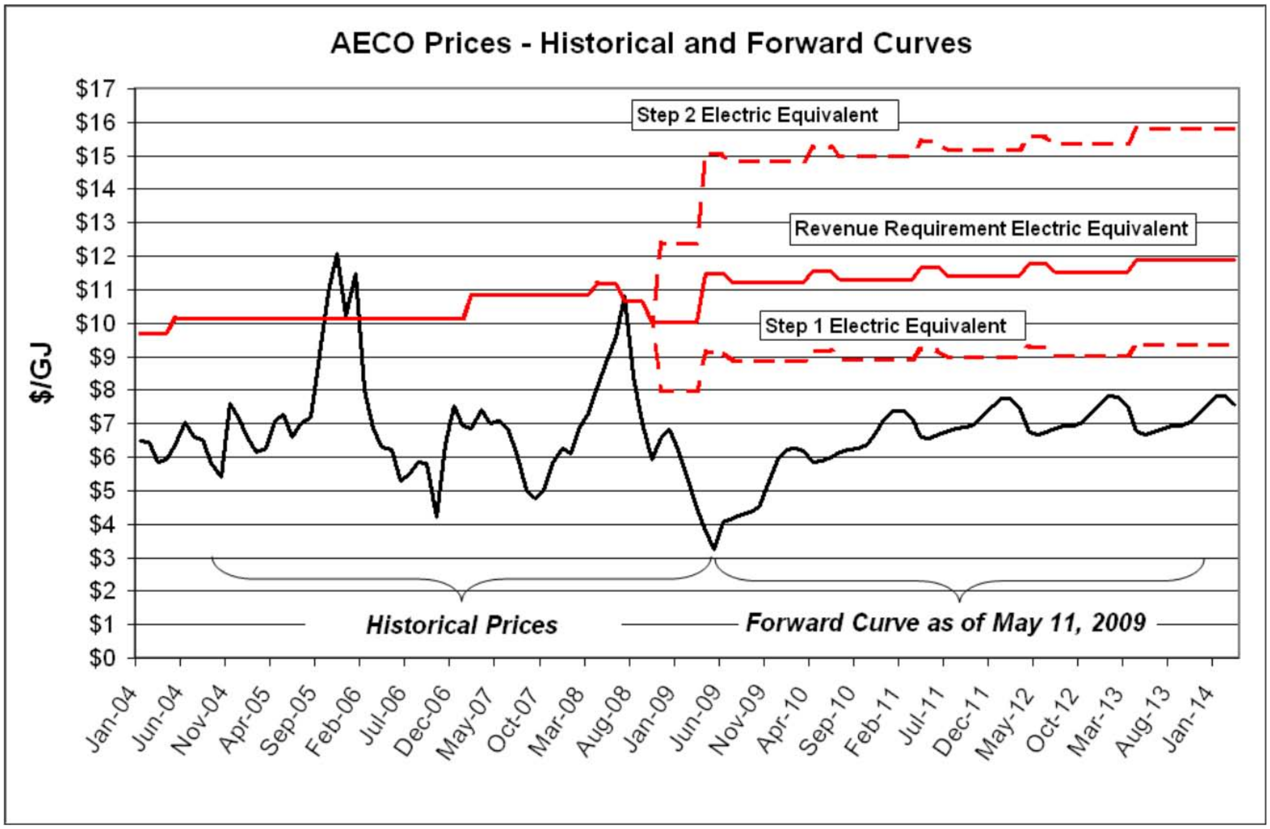


Figure A-5 indicates that at the current gas commodity price, and the current forecast gas commodity prices (forward curve), TGI has a competitive advantage against electricity on an operating cost basis over the next five years. However, the comparison in prices is absent any consideration of the required recovery of the upfront capital cost difference between a natural gas heated home and a home heated by electricity.

[63] AECO - The historical name of a virtual trading hub on the NGX system, located in the province of Alberta, Canada. Now known as the Nova Inventory Transfer (NIT) system operated by Trans Canada Pipelines Limited.

Figure A-6: AECO Prices vs. Electric Equivalent Commodity Component Prices as of July 2, 2008

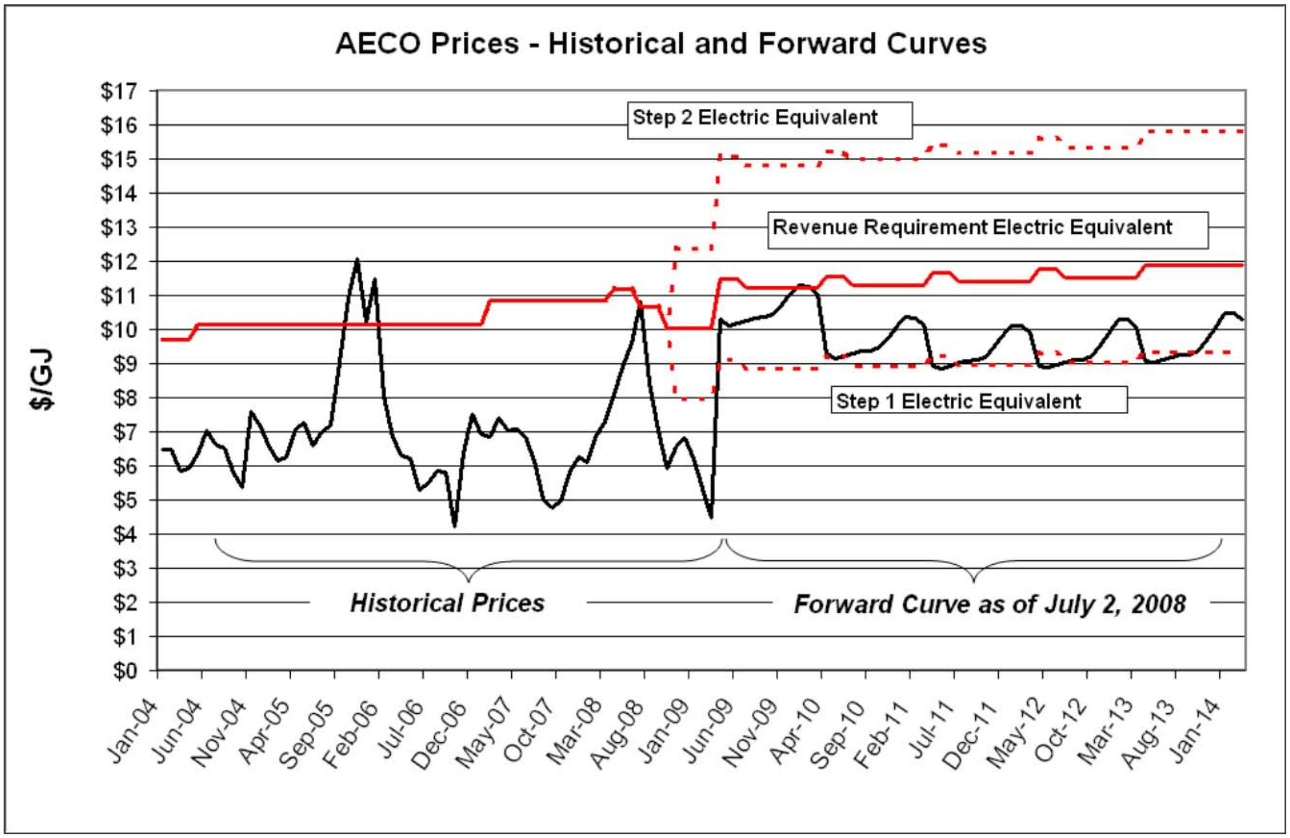


Figure A-6 provides an indication of the volatility of natural gas commodity prices. The forward curve on July 2, 2008 was very different from and substantially higher than, the current forward curve. This graph illustrates the nature of the highly volatile natural gas marketplace in which Terasen Gas operates.

As Figure A-5 indicates TGI has a competitive advantage against electricity on an operating cost basis over the next five years using the current forward curve (as of May 11, 2009). What is not apparent from Figure A-5 is that TGI requires a significant operating cost advantage to overcome the upfront capital cost differential for a natural gas versus an electrically heated home.

Figure A-7 shows the annual energy cost differential between a natural gas heated home and an electrically heated home must be more than $500 per year or $10.31 per GJ over the life of the asset, in order to offset the capital cost differential for natural gas equipment versus electric baseboards. These calculations are based on the assumptions outlined in Figure A-7.

Figure A-7: Payback on Capital Costs Difference for a Natural Gas Heated Home[64]

Payback of Capital Costs (New Construction)

Space Heating Requirement Only
New Construction of home in Lower Mainland (2500 square feet in size)

Capital Costs for High Efficent Furnace (90%) and ducting/installations	$7,000.00
Capital Cost for Electric Baseboards	($2,500.00)
Difference in up front capital costs	$4,500.00
Interest Rate	0.06
Measureable Life of Furnace (years)	18
Amount that has to be recovered in operating cost annually to payoff difference in capital cost	$415.60
Add in furnace maintence costs per year	$100.00
Total ($)	**$515.60**
Energy consumptions for natural gas space heating (GJ's)	50
Difference in cost that needs to exist between natural gas heated home and electricity heated home in $/GJ over 18 years	**$10.31**

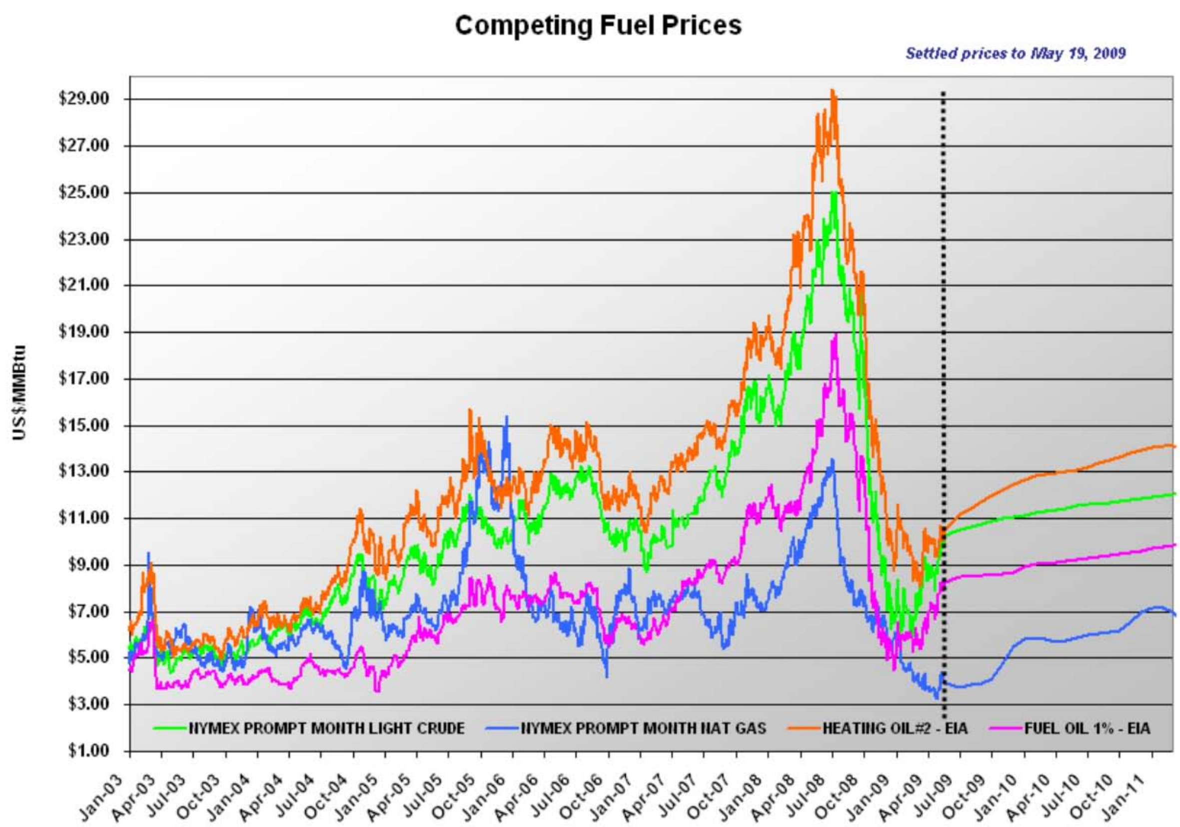
When the capital cost differential of $10.31 per GJ is added to the numbers outlined in Figure A-5, natural gas for space heating applications is not competitive relative to any of the electric rates outlined in Figure A-5, even the Step 2 RIB rate. The disparity in the overall competitiveness of natural gas taking into account upfront capital costs is very concerning given that natural gas commodity prices are lower today than in recent years. Prices are actually below the costs of finding and developing new natural gas supply resources, which suggests that natural gas prices are bound to increase in the future. This reality will have some impact on customers or developers that select energy forms or solutions based economic criteria. However, other customers segments may select natural gas as the solution to meet their energy needs based on a broader set of criteria such as: lifestyle benefits, net reductions in GHG's for the region and making efficient use of energy. Natural gas may also be used effectively in conjunction with other energy sources in, for instance, District Heating Systems.

64 The 50 GJ used in this calculation relates to a new residential home located in lower mainland (2500 square feet). This 50 GJ is for space heating only and does not include other uses of natural gas in the home such as water heating or natural gas stoves. This 50 GJ is lower than the average Rate Schedule 1 use rate of 92.5 GJ for 2008 because the 92.5 GJ is related to the total demand not just the space heating load. Also it reflects a decrease for the higher efficiencies of the new home and new furnace as compared to the existing stock of houses and furnaces.

The operating cost differential between natural gas and electricity for space heating and other direct use applications may improve over time due to higher supply and infrastructure costs for BC Hydro. Recently, natural gas market prices have improved relative to other energy commodities (such as oil) in the North America marketplace (See Figure A-8), but face challenges in the BC marketplace due to the differing nature of how natural gas and electricity costs are set into rates.

As of May 19, 2009 natural gas has a forecasted cost advantage against other fuels used in heating application such as heating oil No.2 and fuel oil (1 per cent). In general, the ratio of oil to natural gas cost has improved from its 5 year historical average of 8.5:1, to a 5 year forecasted ratio of 10.4:1.

Figure A-8: Natural Gas Competiveness in to Other Energy Commodities is Improving on a Go Forward Basis



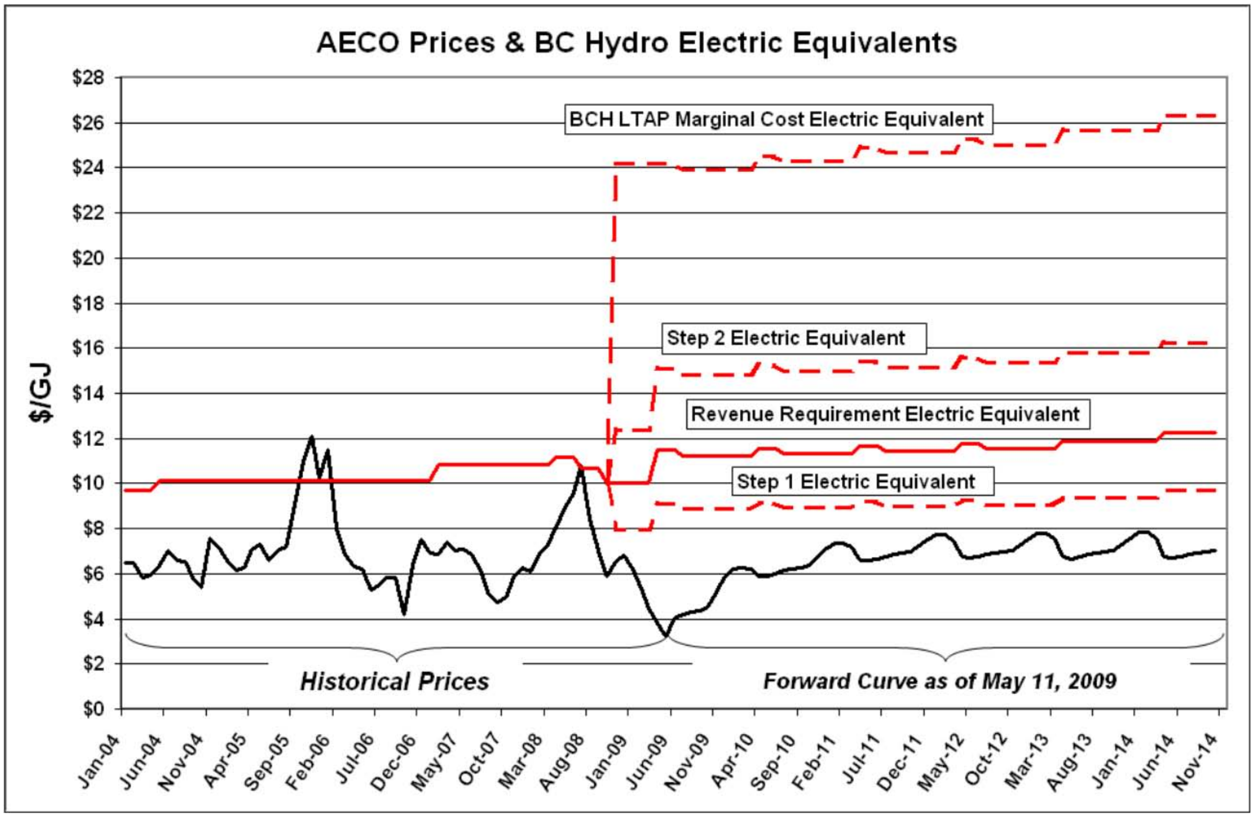
Due to such factors as low embedded (historical) electricity costs and the stated goal by the B.C. Government[65], the Terasen Gas operating environment is unique. As discussed above, this presents some challenges for Terasen Gas going forward. However, as Figure A-9 shows, if natural gas was

[65] See Appendix C-2 for a copy of Energy Plan 2007: A Vision for Clean Energy Leadership, page 4

competing against the marginal cost of electricity, then the natural gas competitive landscape would improve.

Figure A-9: AECO Prices vs. Electric Equivalent Commodity Component

Current Prices as of May 11, 2009 with BC Hydro Marginal Cost of Supply[66]



Absent this market reality, if true price signal cannot take place when alternative energy sources exist it is imperative that the appropriate rates and incentive mechanism, as well as consistent messaging, are in place to encourage the efficient use of all forms energy.[67] For these reasons, we need to invest in informing and educating policy makers, and communities looking to comply with the climate action challenges.

Securing reliable and cost effective gas supply resources is also an important part of trying to remain competitive against alternatives, namely electricity.

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[66] BC Hydro marginal cost of electricity as outlined in the 2008 BC Hydro LTAP is $120/MW

[67] Efficient use of energy – as an example, direct use of natural gas in a new high efficiency natural gas fired furnace operating at 95% efficiency as compared to a modern combined cycle gas fired generator that operates at 50 to 55% efficiency.

On behalf on customers, the Gas Supply Department at TGI, works diligently in trying to meet the long standing objectives related to providing natural gas and propane commodity services to our sales customers.

Terasen Gas is proactive in regional resource developments and influencing the cost of available resources for the benefit of customers. This involves attending industry forums and conferences, being an active member of associations where Terasen Gas can promote its customers' interests, such as through the Northwest Gas Association ("NWGA") and Western Energy Institute ("WEI") and participating in the regulatory proceedings of regional pipeline companies in which Terasen Gas has an interest. Through this work, Terasen Gas has been able to understand how infrastructure is being utilized and developed in the region to meet the gas supply requirements of our customers and fulfill the objectives to provide reliable and cost effective supply resources to our customers.

d) Demand for Perceived "Green" Energy Represents an Additional Challenge

Direct use of natural gas must overcome two hurdles for the buyer to make a commitment to investing in natural gas equipment. One is the economic decision as discussed above. The second is related to the "green" perception of a product and how that product helps in meeting the climate change challenge.

Developers may install electric baseboards since this is the cheapest option from a capital cost perspective. There are also other developers who are looking to find ways to market new building stock as a "greener" alternative. In this type of building stock, builders are not only using electricity as already noted, but they are also looking to use geo-exchange systems, solar hot water systems, wood waste fired systems, and some or all of these fuels in district energy systems. Thus, natural gas may not be seen by some as the preferred option due to this growing trend towards greener alternatives.

Additionally, when Terasen Gas account managers meet with customers, we are increasingly asked about entire suites of energy solutions. Customer expectations are that the gas utility be the provider of information and advice on a range of energy solutions including gas, energy efficiency and alternative energy solutions. This is a marked change from the customer expectations that Terasen Gas experienced in the late 90's up until 2003. During this period, natural gas, primarily because of price and a lack of "green" energy policy, was the desired energy source for heating and comfort applications in homes and businesses.

In B.C., in contrast to other jurisdictions, natural gas is seen in the same light as other fossil fuels rather than being seen as a greener alternative. Customers cannot always be expected to understand the complicated nature of energy production and delivery and, as such, make decisions based upon limited information from media and other communication channels. Therefore, many customers see electricity, and alternative energy, as green and natural gas as "dirty". In most other jurisdictions, moving customers from dirty fuels such as oil and coal fired electricity to natural gas end use or generation is seen as a greener alternative and part of the solution to reducing overall emissions. As we have discussed in other filings[68], natural gas, when used in end-use applications can result in lower GHG emissions and lower total energy use in the region by displacing electricity that is generated from fossil fuel. However, this message is particularly difficult to convey to customers and can result in decisions that, in effect, increase emissions from a regional perspective. An example is developers building and selling houses with electricity as a "green" house. Customers who do not know the complexities of energy will not have a reference point to dispute this selling methodology. Therefore, customers believe that electricity, due to hydro generation, is green is only enhanced by the activities and selling tactics of developers.

As a competitive "green" alternative to natural gas used for water heating, developers of multi-family units may consider solar energy to help meet the needs of their customers. For example, a solar-thermal project in a 40 unit multi-family residential development could provide hot water to the complex for a levelized cost of $9.47/GJ.[69] Such a system would not entirely replace a traditional hot water system, but rather would be expected to provide about 30 per cent of the customer's hot water, reducing natural gas consumption and lowering carbon emissions as a result.[70] This example represents a relatively simple, low cost solution to the traditional hot water system that may have been provided solely by natural gas in the past.

e) Summary

In conclusion, the gradual erosion of the natural gas cost advantage in B.C. versus electricity impacts Terasen Gas' growth in new customer additions, and also impacts throughput levels of existing customers. Increases in natural gas prices incent customers to reduce their energy consumption or look for cheaper alternatives to meet their energy needs. This issue is compounded by the climate change realities and how it will change customers' perception of natural gas. In all cases the result is reduced consumption levels on the natural gas system which negatively impacts existing customer's rates, all else being equal.

[68] BC Hydro 2008 LTAP – Terasen Utilities Final Submission – April 27, 2009
[69] See Appendix C-27 for a copy of Alternative Energy System Cost of Service
[70] See Appendix C-27 for a copy of Alternative Energy System Cost of Service

If true price signal cannot take place when alternative energy sources exist it is imperative that the appropriate rates and incentive mechanisms, as well as consistent messaging, are in place to encourage the efficient use of all forms of energy. For these reasons, we need to invest in informing and educating policy makers, and communities looking to comply with the climate action challenges and we need to invest in the assets and technologies that make these changes possible.

To meet these challenges Terasen Gas believes that the business needs to evolve.

4. BC Economic Outlook and Demographic Challenges

There have been significant changes in global, regional, and local economic conditions since the last Revenue Requirement Application was filed in 2003. These changes have meaningful implications for Terasen Gas' customers. It will impact their ability to pay for energy, impair their ability to make investments in energy conservation measures, lower customer additions and reduced customer demand for energy consumption. In addition to this economic downturn, Terasen Gas faces demographic challenges as do other employers across the country. We must develop different strategies to manage these risks to ensure that we can continue to meet the needs of our customers.

This section looks closely at the changing economic situation in B.C. by looking at:

- B.C.'s Economic Outlook for 2009-2011: Turbulent Times
- A Looming Demographic Challenge

a) B.C.'s Economic Outlook for 2009-2011: Turbulent Times

Generally, during the period of 2003 to 2007, the Canadian economy as a whole was performing well. Specifically the B.C. economy was booming and experienced solid economic growth. However, in 2008 the economy as a whole went into a decline. The B.C. economy was no exception to this trend, and experienced an economic downturn as a result of the US housing market correction and subprime mortgage crises that burst the US economic bubble and triggered a global recession. By the end of 2008, B.C. went through a decline in economic growth, higher unemployment rates, and lower housing starts, all of which have generated concern for how the B.C. economy may perform in the coming years. For further details of the Canadian and B.C. economic conditions for the period from 2003 to 2008 please see Appendix C-28: Economic Review 2003-2008.

The US-led global recession not only makes the future of economic conditions uncertain, but it is anticipated that the economic turmoil will require quite some time before a complete recovery is obtained. Although the recession in the B.C. economy is significantly less pronounced as compared to the US recession and the experience of some other Canadian provinces, risks to B.C.'s economic outlook include a prolonged period of low economic growth, further weakening of domestic demand, and further commodity price volatility.[71] Despite the fact that most economic indicators suggest that global economic conditions may remain turbulent for some time, B.C. is relatively well positioned to weather this storm. There have been signs of economic recovery in recent months with strengthened Canadian dollar[72] and improving commodity prices.[73] As has been experienced in the past, appreciation of the Canadian dollar will likely impact B.C. exports. However, proof that B.C.'s economy is doing better can be seen by employment gains as a result of 17,000 new jobs in the province[74] and urban housing starts[75] gains of 1 per cent in B.C. in April 2009, as compared to other provinces which saw a continued decline.

The following table summarizes the forecast changes in the economy based on the leading economic indicators from 2009 to 2011. The forecasts produced below reflect the best available information at the time of filing.

71 See Appendix C-29 for a copy of B.C. Fiscal Plan 2009
72 See Appendix C-30 for a copy of Loonie's rise dampens rebound
73 See Appendix C-31 for a copy of Canada Stocks – TSX poised to rise on commodity strength
74 See Appendix C-32 for a copy of B.C. gains 17,000 new jobs as Metro Vancouver unemployment drops
75 See Appendix C-33 for a copy of April Housing Starts

Table A-1: B.C. Economic Outlook Not as Bleak as Other Jurisdictions

	2009	2010	2011
Real GDP (per cent change)			
BC[76]	-0.9	2.4	2.6
ON[77]	-2.5	2.3	3.3
AB[78]	-2.0	1.8	3.0
Unemployment rate (per cent)			
BC[79]	6.2	6.0	5.7
ON[80]	8.8	8.9	8.2
AB[81]	5.8	6.5	6.2
Housing starts (per cent change)			
BC[82]	-34	-9	3
ON[83]	-33.4	10	18.2
AB[84]	-23.5	8.1	1.2

As demonstrated in Table A-1 forecast of B.C.'s economic conditions are not as bleak as other jurisdictions such as Ontario and Alberta. Alberta, which has an economy driven by the energy sector and Ontario with strong ties to the US economy are expected to experience a greater downturn in economic activity as compared to B.C. For instance, B.C. is expected to have lower real GDP decline in 2009 and higher economic growth in 2010, when compared to Ontario and Alberta. Moreover, B.C.'s unemployment rate is expected to remain lower than Ontario, where the majority of layoffs have been taking place.

76 See Appendix C-34 for a copy of British Columbia Budget 2009
77 See Appendix C-35 for a copy of Ontario Budget 2009
78 See Appendix C-36 for a copy of Alberta Budget 2009
79 See Appendix C-34 for a copy of British Columbia 2009
80 See Appendix C-35 for a copy of Ontario Budget 2009
81 See Appendix C-36 for a copy of Alberta Budget 2009
82 See Appendix C-37 for a copy of CMHC Housing Market Outlook - BC Region Highlights First Quarter 2009
83 See Appendix C-35 for a copy of Ontario Budget 2009
84 See Appendix C-36 for a copy of Alberta Budget 2009

It is expected that B.C. will post virtually no economic growth on a year-over-year basis in 2009 and many industrial sectors (largely forestry) will continue to be affected by the recession. In fact, B.C.'s real GDP is forecast to decline by 0.9 per cent this year, the weakest performance since 1982.[85]

Also, layoffs are expected to accelerate in many sectors, including construction, real estate and related services, financial services and retail. A total of 35,000 jobs were lost in B.C. in January 2009[86] followed by 14,000 layoffs in the month of February.[87, 88] The unemployment rate is expected to rise to an average of 6.2 per cent in 2009. This slower economic growth and rising unemployment rate will weaken demand for homeownership and thus housing starts are expected to decline by 34 per cent in 2009.[89] This economic reality will have an impact on some customers' ability to pay for basic needs, such as home heating.

In 2010, it is expected that B.C. will reap significant economic benefits and growth from hosting the 2010 Olympic and Paralympic Winter Games. A return to economic growth is anticipated with the province's real GDP forecast to rise by 2.4 per cent.[90] With the expected positive trend for 2010, B.C.'s economic well-being should show slight improvement and the unemployment rate is expected to decrease to an estimated rate of 6.0 per cent. Despite the expected economic growth, housing starts will likely continue to decline by 9 per cent in 2010.

In 2011, it is expected that the B.C. economy will continue recovery at a moderate pace, whereby real GDP is expected to grow by 2.6 per cent. Unemployment is expected to decline in 2011 as the first wave of the baby boomers[91] will reach 65, potentially expanding the number of opportunities in the labour market. Housing starts will likely recover from the declining rates of the last couple of years to 3 per cent in 2011.

Lower economic growth, higher unemployment rates, and declining housing starts indicate that the economic turmoil will most likely impact Terasen Gas by lowering customer additions and reducing customer demand for energy consumption.

85 See Appendix C-38 for a copy of RBC Economics March 2009
86 See Appendix C-39 for a copy of B.C. sheds 68000 full-time jobs in January
87 See Appendix C-40 for a copy of Unemployment rate climbs to 6.7% in B.C.
88 See Appendix C-41 for a copy of B.C. economy to decline 1.5 per cent in 2009
89 See Appendix C-37 for a copy of CMHC Housing Market Outlook - BC Region Highlights First Quarter 2009
90 See Appendix C-34 for a copy of British Columbia Budget 2009
91 Baby Boomers is the name given to the generation of North Americans who were born in a "baby boom" following World War II. The Boomers were born between 1944 and 1964. The oldest wave of the Baby Boomers is currently considering retirement options and looking at ways to make their elder years meaningful.

It is critical to assess the economic conditions for the next three years and the impact of it on the business of Terasen Gas in order to ensure that forecasted costs and revenues in this Application are prudent and necessary to meet the evolving needs of the Company's customers.

Please see Part III, Section C, Tab 4 for more details relating to the economic factors that help determine customers' throughput and new customer additions.

b) A Looming Demographic Challenge

TGI must continue to invest in managing the looming demographic challenge to ensure that we can continue to meet customer needs.

Shifting workforce demographics are a well-known global reality and a major source of concern for governments and businesses alike. Many economists have been predicting for some time that the looming retirement bubble of baby boomers will create serious labour shortages, particularly in the skilled trades and professional occupations. The situation is made even worse by the fact that Canada has been experiencing declining fertility rates and not enough Canadians have been born in the last several years to replace those workers who will reach retirement age in the coming two decades. In an October 2008 report, the Conference Board of Canada noted:

> *"Given low fertility rates in Canada and increased competition for skilled immigrants, the pool of younger workers available to replace retiring baby boomers will not be sufficient to meet employers' future staffing needs."*[92]

Similarly, the Business Council of British Columbia has acknowledged that the challenges of dealing with an aging workforce will be a major concern for many companies:

> *"With a large portion of their workforce approaching the traditional age of retirement, companies are going to have to pay much more attention to succession planning and recruitment than in the past."*[93]

The recent elimination of mandatory retirement in British Columbia represents one strategy aimed at mitigating the risks of an aging workforce and the looming shortage of skilled workers. In 2007 the provinces of British Columbia and Alberta adopted another strategy by signing the Trade, Investment

92 See Appendix C-42 for a copy of Harnessing the Power: Recruiting, Engaging and Retaining Mature Workers

93 See Appendix C-43 for a copy of The Current Challenges Facing Human Resources and Labour Relations Professionals

and Labour Mobility Agreement ("TILMA") aimed at improving access to skilled labour through automatic inter-provincial recognition of various professions and skilled trades such as engineers, electricians, mechanics, and others. TILMA subsequently paved the way for a new national agreement on labour mobility, the Agreement on Internal Trade ("AIT") signed by the provinces on December 5, 2008. This agreement contains two key amendments – a revised labour mobility chapter and a revised Dispute Resolution Mechanism – and is considered to mark a significant milestone towards eliminating internal trade barriers and enhancing labour mobility across Canada. Specific changes to the AIT as it relates to labour mobility are summarized as follows:

> **9th Protocol of Amendment: Labour Mobility (Chapter 7)**
> *"Canadians should be able to work in their chosen occupations anywhere in Canada. The revised labour Mobility Chapter of the AIT will provide that any worker certified for an occupation by a regulatory authority of one province or territory is to be certified for that occupation by all others.*
>
> *Any exception to full labour market mobility will have to be clearly identified and justified as necessary to meet a legitimate objective, such as the protection of public health or safety.*
>
> *The Committee of Internal trade has approved, in principle, that all Canadians will enjoy full labour mobility by April 1, 2009."*[94]

In a news release issued March 12, 2009, the Government of British Columbia announced its endorsement of the new AIT as follows:

> *"The new AIT removes a long-standing barrier, and further enables B.C. to attract, and quickly employ, the skilled trades and professions needed in many sectors – especially important as retirements over the next 10 years are forecast to exceed the total number of students currently in the B.C. post-secondary system."*[95]

The Business Council of B.C. has forecast over a million job vacancies by 2018 while only 650,000 young people will move through the province's K-12 school system over the same period. This is expected to result in a "shortfall" of 350,000 prospective workers as measured against the expected number of job openings even if all the K-12 graduates remained in B.C.[96]

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[94] See Appendix C-44 for a copy of Agreement on Internal Trade
[95] See Appendix C-45 for a copy of B.C. Leads Canada with Labour Mobility Bill
[96] See Appendix C-46 for a copy of The Role of Temporary Foreign Workers in Easing Labour Shortages

Professional associations have also expressed concern about attrition in their membership. In October, 2007, the Applied Science Technologists and Technicians of British Columbia ("ASTTBC") held a Roundtable on Technology Skills Shortages with stakeholders representing all sectors to engage in a discussion on the critical shortage of skilled workers in British Columbia. One of the actions coming out of the Roundtable was:

> *"…the formation of a Technology Education & Careers Council ("TECC") to provide strategic leadership and advocacy in advancing the importance of technology careers and education in B.C., serve as a catalyst for action and articulate industry policy with governments and educators."*[97]

TECC members are drawn from industry and stakeholder leaders, and includes the Vice President of Human Resources and Operations Governance at Terasen Gas. The mandate of the TECC is to oversee and champion a Technology Skills Action Plan to proactively address the following concerns:

- Almost half of the current technologists and technicians will retire as the oldest baby boomers start to leave the workforce.
- The B.C. and Canadian economies are forecast to grow steadily, led by the high tech sector and technology-based processes.
- In B.C. the 2010 Olympic and Paralympic Winter Games, construction and real estate development, mining and resource projects, and the growth of the province's cities and population, have and will create a huge surge in demand for trained and qualified workers.
- By 2010, there is projected to be a 70 per cent shortfall in the supply of needed supervisors, managers and contractors in trades and technologies.
- In the meantime, B.C. post-secondary institutions are closing down and reducing spaces in technology programs, and few opportunities are provided for technology workers to complete necessary continuing education and lifelong learning.

The demographic challenge facing employers across the country is very real. Businesses must also develop different strategies to manage these risks, and for Terasen Gas the demographic challenge is more daunting than most. From a Human Resources perspective, our Application will outline the magnitude of this challenge, identify what HR strategies have already been undertaken and what additional actions will be required to effectively manage the risks over the next several years (see Part III, Section B, Tab 2).

[97] See Appendix C-47 for a copy of Roundtable on Technology Skills Shortage II

c) Summary to B.C. Economic Outlook and Demographic Challenges

In general, the economic conditions in B.C. for the time period 2009-2011 have worsened compared to most of the time covered by the PBR Period. Lower economic growth, higher unemployment rates, and declining housing starts indicate that the economic turmoil will most likely impact Terasen Gas' customers. It will impact their ability to pay for energy, impair their ability to make investments in energy conservation measures, lower customer additions and reduce customer demand for energy consumption.

In addition to this economic downturn, Terasen Gas faces demographic challenges as do other employers across the country. Businesses must develop different strategies to manage these risks, and for Terasen Gas the demographic challenge is more daunting than most in meeting customer evolving needs. See Part III, Section B, Tab 2 for how Terasen Gas will address this demographic issue.

5. Accounting Standards and Related Guidance are in Flux

Accounting standards and related guidance are continually evolving to anticipate and react to changes in the requirements and expectations of financial statement users. These requirements and expectations often result from the same changes to legislation and to the external environment that were discussed above. Pending changes in accounting standards are the single greatest cost driver of the rate increase sought in 2010 and 2011.

Canadian utilities are required to comply with accounting standards known as Canadian Generally Accepted Accounting Standards ("GAAP"). The guidance contained in these standards has been reflected in the determination of rates. As GAAP has evolved, the resulting changes have been incorporated into revenue requirements filings with Canadian regulatory bodies.

In recent years, there has been an accelerated pace of change in Canadian GAAP, and the resulting standards have become increasingly more complex. Of particular note are changing standards on financial instruments and hedging, corporate income taxes, asset retirement obligations, variable interest entities, asset impairment, stock based compensation, employee future benefits, comprehensive income, goodwill and intangible assets, inventories, and rate regulated entities.

Canadian accounting standards are now entering a time of unprecedented change, as the standards that are applied in the creation of financial statements, and also incorporated in the determination of rates, change from Canadian GAAP to IFRS. Canadian utilities will be required to comply with IFRS for financial reporting periods commencing on January 1, 2011, with comparative figures for 2010 restated to be in compliance with IFRS. Canadian utilities must be ready and able to reflect the 2010 effects of IFRS in both their financial statements and their revenue requirements filings.

Changes in accounting policies do not change the amount of total costs to be recovered from ratepayers, but changing standards do affect the timing of when those costs are recovered. Rates may rise in the short term, but this initial rise in rates will be offset by lower rates in the future.

Further details on the specific changes required to comply with IFRS and the implications of those changes on Terasen Gas' revenue requirements are contained in Part III, Section C, Tab 11.

Summary for the External Situation Context

The factors outlined in this section present a picture of increasing demands of, and pressure on, our base business, while also presenting opportunities to expand and evolve our service offerings to meet the challenges of energy efficiency and climate change policies. Terasen Gas is committed to creating the long-term solutions and business models that will allow its customers and communities to address these challenges. The Application reflects the imperative to invest in our ability to serve customers and expand our ability to offer comprehensive energy solutions.

B. Respected and Trusted Operator

1. The Past

Over the course of the six year period commencing in 2004, Terasen Gas has been operating under the terms of the PBR Agreement. During the PBR Period there have been a number of significant changes in the external environment experienced by TGI, as discussed in detail in Part III, Section A of this Application. The Company has successfully managed these challenges, delivering service to our customers in a safe, reliable and cost effective manner. The Company intends to build on this success in responding to these ongoing, significant challenges.

In this section of the Application we review the initiatives we have undertaken during the PBR Period to respond to the various challenges, and the performance of the Company in that regard. We then discuss how we are presently responding to these challenges and how they will shape our intended actions into the future. To facilitate this review, this section of the Application has been separated into two major sub-sections, being The Past and The Future. The Past and Future sub-sections have been organized into the following five areas: management excellence; customer service; operational performance; employees and financial results.

a) Past – 2003 to 2009

TGI has performed well during the PBR Period in the five key areas of management excellence; customer service; operational performance; employees and financial results. A brief explanation of those five areas is set out immediately below, followed by a detailed discussion of each.

1. *Management Excellence*: In this section we will describe the corporate governance structure and our actions taken to meet compliance requirements. It includes discussion of the Company's management processes employed to ensure Capital and O&M spending are managed prudently on behalf of customers and its shareholder, as well as the Company's Balanced Scorecard approach.

2. *Customer Service:* This section will discuss how the annual demand for natural gas has declined as has the rate of customer growth over the PBR Period, while at the same time Terasen Gas has maintained a stable delivery rate and has met the evolving needs of our customers. This is followed by discussion about how Terasen Gas has interacted with customers including discussion on three of the more significant regulatory applications related to improving customer service, Energy Efficiency and Conservation, Commodity Unbundling and the System Extension Test.

3. *Operational Performance:* In this section we will describe how the Company has responded to the evolving regulatory and business needs. This will include discussions on our Code Compliance efforts, our Carbon Management initiatives, our Information Technology Strategy and how the Company has delivered on major projects, all of which are key operational areas for Terasen Gas.

4. *Employees:* This section will discuss how Terasen Gas has concentrated on attracting, retaining and motivating employees over the PBR Period, and how it has responded to the changing needs of employees. The Company will describe the key areas where it has been able to demonstrate its commitment to its employees regarding employee safety, managing changing employee demographics, and developing talent.

5. *Financial Results:* This section will describe the incentive mechanisms that were included in the PBR Agreement. It will demonstrate how Terasen Gas accepted the challenge that the incentives presented and was able to achieve significant efficiency gains to be shared by customers and the Company over the PBR Period. This section will also discuss the operating and maintenance expenses and capital expenditures over the PBR Period, in addition to the significant savings the Company has achieved.

(1) MANAGEMENT EXCELLENCE

Terasen Gas is committed to continuous improvement and Operational Excellence for the benefit of customers and its shareholder. For Terasen Gas, Operational Excellence means the prudent combination of service quality to our customers and the cost of providing those services, while ensuring employee and public safety, and operating in an environmentally responsible manner. TGI's strong corporate governance structure, with clear division of management responsibilities and well defined policies and procedures set out and monitored for performance, is important for achieving Operational Excellence.

The next section describes Terasen Gas' corporate governance structure, and our actions taken to meet compliance requirements. It includes discussion of Terasen Gas' management processes utilized to ensure Capital and O&M spending are managed prudently. Following is a discussion of the USP, an example of Terasen Gas' ongoing commitment to Operational Excellence. Department overviews are then provided for reference. Lastly, the Balanced Scorecard approach is discussed and how it has served Terasen Gas well as an important means of improving organizational alignment and focusing activities on those that matter the most.

(a) Management Structure and Constructs/Processes

Terasen Gas' success in realizing efficiencies during the PBR Period for the benefit of customers and its shareholder reflects the effective management structure and constructs the Company has in place. Strong corporate governance coupled with compliance activities, an effective information technology utilization strategy, defined policies and procedures that aid in effective decision making, particularly in capital and O&M spending have collectively contributed to the strong results Terasen Gas has achieved.

(i) Strong Governance Structure

Having a well-defined governance structure which spells out the policies and procedures for making decisions and provides the structure through which the organization's objectives are set and monitored ensures accountability and transparency of the Company's actions to its shareholder, customers, employees, regulators and other stakeholders.

Terasen Gas has in place an organization and culture that embodies strong governance. The Board of Directors of Terasen Gas (the "Board") is responsible for the stewardship of the Company and is comprised of a majority of independent members. The Board and Management of Terasen Gas acknowledge the critical importance of good corporate governance practices in the proper conduct of the business and affairs of the Company. The Company has established governance policies and procedures which include independent Board oversight of strategic direction, management and organization structure, financial and risk systems, employee conduct, and the effectiveness of management.

Comprised of the President and the Vice Presidents representing the major departments of the organization, the Executive Leadership Team ("ELT") is responsible for providing overall leadership and strategic guidance to manage the combined operations of the Terasen Utilities. The ELT determines the strategic direction of the Company and develops business plans in support, including the setting of the performance targets for the Company's scorecard. The ELT works closely with the Utilities Operating Committee ("UOC") to ensure the Company's business goals and objectives are achieved, helping to meet the needs of its customers, employees and shareholders.

The UOC was established in mid-2008. It is comprised of senior managers appointed from the various departments within Terasen Gas under the strategic guidance of the ELT. The UOC is responsible for making and implementing tactical decisions for the combined operations of the Terasen Utilities. To meet the needs of Terasen Gas' customers, employees and its shareholder, the UOC's mandate is to deliver on the targets as setout on the Utility scorecard while maintaining the utility's focus on Operational Excellence. The Utility scorecard contains four categories of key success measures important to the Company's performance. Further discussion on the Utility scorecard can be found in this section on the Balanced Scorecard.

The UOC is accountable to the ELT and consults with the ELT with respect to Strategic Operational Planning, guiding the formulation of the Utility scorecard.

With broad representation from different parts of the organization to ensure knowledge and understanding of key issues, the UOC is able to make effective capital spending decisions by prioritizing the spending, focusing on prudence while administering the review and approval process efficiently.

In the past number of years, Terasen Gas has developed and put in place the necessary governance structure to ensure the actions it takes are appropriate and effective. In 2001, Terasen Gas implemented an Enterprise Risk Management ("ERM") framework and risk management process that was specifically aimed at ensuring that Terasen Gas complied with applicable securities commission's policies and requirements for effective risk management. Terasen Gas is leveraging its existing ERM framework and risk management process to ensure a consistent risk-based approach to certification compliance efforts, helping to reduce the organization's risk with regards to potential misrepresentations and internal control weaknesses.

Terasen Gas takes its Canadian securities disclosure requirements seriously and follows a best practice approach with respect to its compliance plan and approach. In recognition of the Company's excellence in implementing effective governance processes with specific emphasis on its ERM initiative, in 2003 Terasen Inc. ("Terasen") received the Conference Board of Canada / Spencer Stuart Private Sector National Award in Governance and was the overall winner. Terasen was honoured for "*demonstrating strong internal principles, values and leadership*."

Today, ERM forms an integral part of Terasen Gas' business and strategic planning processes and will continue to in the future. In the environment we are in today, changes in economic, political, regulatory, and competitive risk factors will occur. Monitoring of these changes in the risk environment is crucial in order for Terasen Gas to maintain its track record of success.

Terasen Gas puts a high priority on the safety of its employees and the public and on minimizing its impact on the natural environment. To achieve this, Terasen Gas has in place an Operational Governance department responsible for the management systems that monitor and support engineering governance, environmental affairs, employee occupational health and safety, public safety, emergency preparedness, and security. These systems and programs assist Terasen Gas in ensuring environmental compliance and a safe environment for customers, the public and employees.

(ii) Internal Audit

Terasen has an Internal Audit Services ("IAS") department that reports through the Chair of the Audit Committee of the Board of Directors. The primary role of IAS is to provide independent, objective assurance and consulting services designed to add value and improve the organization's operations. IAS provides assurance to the Audit Committee and senior management that Terasen Gas is achieving its business objectives and that business risks are being effectively managed. The focus of IAS is to determine whether the organization's risk management, control and governance processes, as designed and represented by management, are adequate and functioning.

In support of this, IAS annually prepares a Control Assurance Plan for the Terasen group of companies, designed to satisfy organizational and Corporate Governance objectives. The Control Assurance Plan is designed to ensure that the Company has appropriate controls in place to achieve the following objectives:

- effectiveness and efficiency of operations including the safeguarding of assets;
- reliability of internal and external reporting; and
- compliance with applicable laws, regulations and internal policies.

(a) Canadian Securities Disclosure Compliance

Canadian securities disclosure requirements under the Canadian Securities Administrators National Instrument 52-109 (NI52-109) Certification of Disclosure in Issuers' Annual and Interim Filings as it relates to internal controls over financial reporting, provides a level of review and control in ensuring that the Company has appropriate and effective management and control systems in place. Since 2004 when certification requirements were introduced, Terasen Gas has been in compliance with all disclosure requirements and has maintained unqualified certification status throughout the period.

As part of the Control Assurance Plan, Terasen Gas' IAS identifies work required to assess management's design and operating effectiveness of internal controls over financial reporting and disclosure controls and procedures. Activities performed by IAS to support this objective include carrying out a quality assurance review of process and key control documentation; making assessments of design of internal controls; and performing effectiveness testing.

(iii) Policies and Procedures

As mentioned earlier, having well written and clearly communicated policies and procedures is an important part of having a strong governance structure. The policies and procedures allow employees to understand their roles and responsibilities within established limits. Effective policies and procedures provide direction and ensure consistency in day-to-day operational activities, ensuring accountability at the appropriate levels. This, in turn, assists the Company in achieving its business objectives.

Terasen Gas has clear, well documented policies and procedures in the key parts of its business, providing assurance that functions and activities are being managed accordingly and appropriately, contributing to achievement of excellence in its Operational and Financial activities. Of its policies and procedures, the Financial policies and processes affecting Capital and O&M spending are discussed in further detail in the next two sections as they have the most direct impact on the cost of delivering Operational Excellence.

(iv) Capital Spending

From 2004 to 2008, Terasen Gas incurred and prudently managed over $700 million in capital expenditures on a cumulative basis. Capital expenditures include both Regular Capital and those projects approved pursuant to a CPCN. Regular Capital expenditures include those required to provide service to new customers (mains, services and meters), sustaining capital expenditures required to maintain the integrity and reliability of the Distribution and Transmission facilities and Other Capital including IT Capital and non-IT Capital (i.e. buildings, tools and equipment, alteration and replacement of gas mains and services) to service the business needs of Terasen Gas and its customers. Prudent management of Capital Expenditures has benefited customers as well as the Company as intended under the capital incentive mechanism included in the PBR Agreement (the capital incentive mechanism, as well as the efficiencies realized by customers over the PBR Period are described in this section under Financial Results and Performance over the PBR Period – page 157). Customers and the Company have shared equally in efficiencies realized by virtue of capital expenditure savings as measured against the allowed capital expenditures.

To manage these capital expenditures effectively, Terasen Gas has in place clearly defined processes for budgeting, approving and authorizing capital expenditures. Requests for capital funding are balanced against safety and reliability requirements and prioritized to ensure that capital is put to its best use and the impact on customers' rates arising from capital expenditures is minimized.

Five-year capital plans are updated and prepared annually outlining Terasen Gas' capital spending required to meet future customer demand and to provide safe, reliable and efficient gas service to customers.

Transmission and distribution systems are assessed for their ability to meet forecasted growth for natural gas demand in Terasen Gas' service territories. Planning for transmission system expansion is based on a peak day demand forecast for core market customers and firm demand from transport customers. Planning for distribution system expansion and reinforcement is based on assessments of expected customer and load growth and the integrity of the distribution system. Capital spending for new mains, services and meters to attach new customers is determined based on the forecast level of customer additions.

Other capital funding requirements for ongoing business operations and to meet customer needs, including IT initiatives, tools and equipment purchases and meters purchases, are also developed based on input from the different departments within Terasen Gas.

Terasen Gas' Capital Approval policy outlines an approval process with defined responsibilities and approval limits to ensure appropriate capital spending decisions are made. Annual capital budgets require the approval of the ELT. After approval of the capital budgets and before actual capital spending occurs, capital projects are subject to a review process. Subject to the approval limits granted under the Capital Approval policy, responsibility for reviewing and approving capital budgets and funding requests rests with the UOC. In the situation where the capital project in question has been reviewed as part of the capital budget process, no further approval is required. Projects requiring additional approval are brought forth by UOC to the ELT for discussion and review. The decision to approve the funding request is based on a number of considerations including the business imperative, risk associated with not proceeding and risk mitigation strategies available. However, where the capital project is considered ex-budget (i.e. not previously identified in capital budget or requires funding exceeding the authorized level specified in the budget), higher approval by either ELT or the Board is required depending upon the level of ex-budget funding required. Currently, Terasen Gas' policy is to have all ex-budget funding requests up to $500,000 per project approved by the UOC. Individual projects requiring ex-budget funding exceeding $500,000 but less than $5 million require further approval from the ELT. Any ex-budget funding over $5 million per project requires Board of Directors approval.

To ensure effective prioritization of funding for IT capital projects, Terasen Gas requires that all IT capital projects regardless of dollar value must be presented to the UOC for review and approval.

Capital projects that require CPCN approvals are subject to additional internal review in addition to senior management and Board of Directors approvals where necessary, prior to a CPCN application being filed with the Commission.

Authorization of spending for Customer Driven Capital comprised of Mains, Meters and Services for new customers are guided by Terasen Gas' System Extension and Customer Connection policies. These policies were recently reviewed and approved by the Commission in its Order No. G-152-07 dated December 6, 2007. The updated set of policies promotes fair and equitable treatment of customers while contributing to sending the appropriate pricing signals regarding energy choice and use in British Columbia.

(v) O&M Spending

O&M expenditures include those required to operate the Company's business and service the needs of its customers. From 2004 to 2008, Terasen Gas cumulatively has incurred and prudently managed approximately $1 billion in O&M expenditures required to provide safe, reliable and efficient gas service to customers.[98] Prudent management of O&M costs has benefited customers and our shareholder. The incentive mechanism included in the PBR Agreement shares O&M savings as measured against the allowed O&M equally 50/50 between customers and the shareholder. The O&M savings realized by customers over the PBR Period are described in on page 159 of this Section.

Terasen Gas has clear, defined and effective processes in place for budgeting, approving and authorizing O&M expenditures. Requests for O&M funding are assessed against safety and reliability requirements and prioritized to ensure that funding is put to its best use and the impact on customers' rates arising from O&M expenditures is minimized.

O&M budgets are reviewed, updated and approved annually by the ELT. During this process, Terasen Gas operating departments must justify incremental funding requests. The process also involves a review and re-justification of existing budgets. This approach to budgeting is better suited to achieving an optimal allocation of resources since it provides a stronger linkage than an exclusively incremental approach between overall resource allocation to the organization's goals and objectives.

As with Capital spending, O&M spending is managed by the UOC, under the strategic guidance of the ELT. The UOC has responsibility for reviewing and approving O&M budget and funding requests. ELT approval is required in the event that the UOC determines that total O&M funding will exceed the

98 See Appendix F-1 for a copy of O&M Expenditures History

authorized level specified in the budget. To meet the needs of Terasen Gas' customers, employees and its shareholder, the UOC's mandate is to deliver on the targets as determined by ELT and set out on the Utility scorecard while maintaining the utility's focus on Operational Excellence.

With broad representation from different parts of the organization to ensure knowledge and understanding of key issues, the UOC is able to make effective O&M spending decisions by prioritizing spending, focusing on prudence while administering the review and approval process efficiently.

(b) Utilities Strategy Project (USP)

The USP, a major restructuring initiative undertaken in 2004, is an example of Terasen Gas' ongoing commitment to Operational Excellence. Shortly after the acquisition of TGVI and TGW in 2003, the three companies undertook a major restructuring initiative aimed at delivering substantial operating cost savings. The USP was established to implement a single management team along with common work processes and IT platforms. The objective was to create a more cost-effective and sustainable organization and provide long-term benefits to its customers and its shareholder.

Initial costs of approximately $15 million incurred for restructuring and investment in information technology have resulted in sustainable annual savings of approximately $10 million per year for the three utilities collectively. Today, the companies continue to operate with a common management structure with sharing of services and resources under a Shared Services agreement, allowing the companies to maintain an optimal level of resources and avoiding duplication for the benefit of customers.

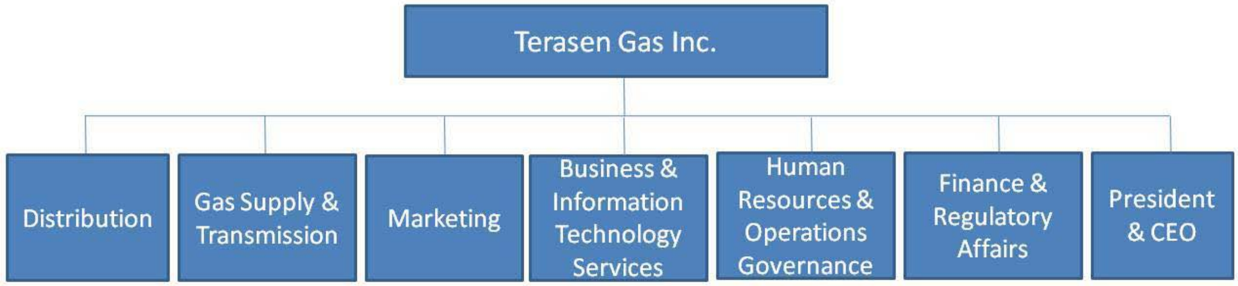
The USP capitalized on the Company's demonstrated competency in Operational Excellence.

(c) Departmental Overviews

Corporate organization influences the effectiveness of its employees in decision making and resource optimization throughout the organization. An effective organization outlines clear division of responsibilities and accountability at different levels of the Company. Terasen Gas has been able to realize cost efficiencies during the PBR Period by virtue of its corporate organization, providing value to its customers and shareholder.

Terasen Gas is currently organized into seven major departments, each responsible for different activities in support of providing safe, reliable and cost effective gas service to its customers.

Figure B-1-1: Organizational Chart by Department



The seven departments and their responsibilities are described below.

(i) Distribution

The Distribution department is responsible for managing the distribution assets, operating the gas system, and providing a safe, reliable and cost-effective distribution service for all gas customers. Field personnel are trained and equipped with tools, equipment and vehicles to provide emergency response, operate and maintain the gas delivery system and to perform installations and renewals.

The department is organized to maximize synergies between the various activities necessary while at the same time maintaining a commitment to providing safe, reliable and cost effective gas service. The activities within Distribution can be categorized into four main functions or business processes, Emergency Management, Installation and Renewal, Operations and Maintenance, and Account Services, which are all described below. Additionally there are several support groups within Distribution that are described.

(a) Emergency Management

Emergency Management includes providing support for first and rapid response in order to ensure public and employee safety. The activities include first response to system damage, gas odours, fire and carbon monoxide calls, emergency prevention through public education, and maintaining stand-by resources. Personnel and resources are mustered throughout Terasen Gas's service area to provide timely response in attending to emergencies, similar to the way fire departments are organized.

(b) Installation and Renewal

Emergency response staff must be located throughout Terasen Gas service area (fire department concept). To the extent these employees can be engaged in installation of service lines, mains and meter sets, it serves to maintain their skill sets and dilute the standby costs of emergency preparedness and response. It should be noted that a significant portion of installation and renewal activities are performed by external contractors particularly during periods of high customer growth.

(c) Operations and Maintenance

Operations and Maintenance includes scheduled and unscheduled operating and maintenance activities dedicated to mitigating operating risks and ensuring the safety and reliability of the distribution system. Activities include system inspection, leak survey, and preventive and corrective maintenance of equipment, valves, stations and meter sets. The level of activities required is influenced by code and standard requirements (i.e. CSA), regulatory requirements, operating conditions, asset age and the geographic footprint of the distribution system.

(d) Account Services

Account Services represents work performed by Distribution staff relating to premise calls, meter lock-offs, unlocks, pilot light relights, meter exchanges/renewals and other customer inquiries requiring a field workforce response. An example of this is a high bill complaint initiated by a customer where a visit to the customer's premise to ensure the meter is functioning correctly may be required.

Supporting the above functions are Distribution Asset Management, Distribution Process Support and the Operations Centre. The support departments within Distribution provide the necessary expertise to assess work priorities, plan and design work to be completed, establish and maintain processes to be followed, and coordinate who and how the work gets completed on a 24/7 basis. They also examine costs and monitor business performance to look for opportunities for further efficiencies

By adopting a business process focus, the Distribution department is able to maintain its commitment to providing safe, reliable and cost effective service. This ongoing commitment will serve to benefit our stakeholders and customers in the years ahead.

(ii) Gas Supply and Transmission

Having effective gas supply and transmission system management is necessary to ensure reliable, secure and cost effective supplies of natural gas and propane to customers.

(a) Gas Supply

The Gas Supply department provides the gas and propane supply management function, which encompasses most elements of the merchant role, providing supply to firm and interruptible customers as well as providing transportation services for industrial and commercial customers. The Gas Supply department provides these services in a reliable, prudent and cost effective manner.

The Gas Supply department ensures that there are reliable and secure supplies of natural gas and propane for the TGI, TGVI and TGW customers at an optimum cost. The key objectives of the Gas Supply department are as follows:

- provide natural gas and propane supply for customers;
- optimize resources to minimize the overall supply portfolio costs for the benefit of customers;
- manage market price risk to reduce volatility on resultant rates for customers;
- provide Energy Management Services to create value for customers through revenue generation; and
- manage commercial and industrial transport customers on the TGI and TGVI systems.

The development and implementation of the Annual Contracting Plans and Price Risk Management Plans play a critical role in managing these objectives. The Annual Contracting Plans outline the portfolios required to meet the needs of core customers through contracting for an optimal and diversified mix of commodity, storage and transportation resources. The plan outlines the details for procurement activities, and also addresses longer-term issues to provide an indication of anticipated longer-term contracting or marketplace changes. The Price Risk Management Plans satisfy the primary objective of reducing market price volatility and resultant rates for customers and also improve the probability of remaining competitive with electricity rates over the longer term in order to attract customer growth and ensure optimum resource portfolios and overall cost-effectiveness for all customers. The Price Risk Management Plans are designed within the context of the highly volatile natural gas and propane markets and include consideration of both high and low market pricing scenarios in the interest of smoothing volatility and reducing the likelihood of rate shock for customers. These plans are filed with the Commission for approval on an annual basis.

Managing these objectives also includes providing intra-day balancing supply (required primarily due to weather changes) for core customers; facilitating all gas scheduling and nominations on the Terasen Gas and third party pipeline transmission systems; mitigation activity based on buying and selling around excess resources; and the management of relationships with financial and physical supply counterparties, storage operators and pipeline companies to the benefit of Terasen Gas' customers. Also included is the management of the movement of gas supply provided by marketers to customers under the commodity unbundling program. As part of the Essential Services Model, the Midstream department within the Gas Supply department provides the Midstream resources required to ensure commodity supply from marketers reaches downstream customers. Consideration is also given to new "green" sources of gas supply which is a significant and important part of the Terasen Gas long term growth strategy. An example is the biogas service offering which is detailed in the Energy Efficiency and Conservation and Alternative Energy Solutions in Part III, Section C, Tab 3 of this Application.

The Transportation Services department within the Gas Supply department manages transportation and marketing services on Terasen Gas' pipeline system, overseeing on-system gas transportation and industrial, commercial and marketer agent services. This includes coordinating nominations and scheduling third-party shipper requests onto the Terasen Gas system. Employees within the Transportation Services and Midstream departments work closely together with employees in the Transmission Gas Control department to ensure gas supply reliability and adherence to terms of the transportation tariffs. Managing imbalances is critical to both the Transportation Services and the Midstream departments to ensure effective use of resources for customers and managing industrial and commercial services according to tariffs is crucial at the time of curtailment or periods of short supply on the Terasen Gas system.

(b) Transmission

The Transmission department provides the asset management function that ensures that the Terasen Gas transmission system delivers natural gas from interconnecting pipelines or Terasen Gas-owned LNG facilities to the distribution network in a safe, reliable and cost effective manner. The Transmission department is responsible for the safe and reliable operation and maintenance of the Interior Transmission system mainline, Southern Crossing Pipeline, Coastal Transmission system, some transmission pressure lateral pipelines, mainline compressor stations, and the LNG plant at Tilbury. The Transmission department is also responsible for the safe and reliable operation and maintenance of the TGVI transmission system which will include the Mt. Hayes storage facility when it is completed in 2011. These costs are either direct TGVI costs or allocated through the shared services agreement between TGI and TGVI.

The Transmission department is comprised of the following departments:

- The Transmission Operations department is responsible for managing the gas control centre including the Supervisory Control and Data Acquisition ("SCADA") system; managing the day-to-day operations of the transmission pipelines, rights of way, compressors and LNG plant; and providing technical support and emergency management to other Terasen Gas operating departments.

- The Transmission Asset Management and Improvements department is responsible for assessing transmission asset health and, with the Transmission Operations department, in establishing inspection and maintenance plans as well as determining and planning infrastructure projects required for system reliability and to meet demand growth.
- The System Integrity department, while functionally in the Operations Engineering department, is an Asset Management service provider for Transmission and Distribution. Reporting to Transmission on budget and work priorities, the System Integrity department has responsibility for executing the Transmission Pipeline Integrity Program ("TPIP") on behalf of the Transmission department.

By organizing into the two main business functions, the Gas Supply and Transmission department is able to maintain its commitment to provide reliable, secure and cost effective supplies of natural gas and propane to customers. The two groups within the department also work together in monitoring and assessing regional market developments and identifying opportunities to create additional value for Company owned transmission assets. Given the importance of these functions to providing safe, reliable and cost effective gas service to customers, Terasen Gas will continue to place high priority on these activities.

(iii) Marketing

The Marketing department plays an important role in meeting the needs of customers and stakeholders. The primary responsibilities of the Marketing department are to manage relationships with existing customers, market development and sales to new and existing customers, managing internal and external communications, and facilitating business relationships with governments and First Nations. Included in the responsibilities are design and delivery of energy efficiency programs and management of outsourced call centre and billing functions with Customer Works Limited Partnership ("CWLP").

To meet the needs of our customers most effectively and efficiently, the Marketing department activities are organized into four areas of responsibility:

- Customer Information and Education – This includes activities such as communications, safety messaging and new project consultation.

- Customer Solutions and Services – This includes activities such as sales, account management, resource planning, market development, technical sales support, energy efficiency and conservation and forecasting.
- Customer and Business Facilitation – This includes activities such as community and government relations and policy, and First Nations relations.
- Customer Care and Services– This includes activities for the management of the CWLP agreement, bad debt management, and support of construction services through the customer contact centre.

As energy use and customer and community needs continue to evolve, the importance of the Marketing department's activities required to respond to these needs will grow. In anticipation, Terasen Gas must continue to enhance its marketing activities and resources including evolving its organization, to be able to respond most effectively to these needs both now and in the future.

(iv) Business and Information Technology Services

Having effective services in support of front line operating departments is necessary to enable the departments to deliver on the Company's commitment to Operational Excellence. The Business and Information Technology Services ("B&ITS") department provides support services to other departments of the Company and is organized into six departments; IT, Facilities, Operations Engineering, Operations Support, Procurement and the Project Management Office ("PMO"). The following is a discussion of the six departments and their responsibilities.

(a) Information Technology

The IT department is responsible for the planning, delivery and ongoing support of information technology and telecommunication services to the Company. The IT department's primary goal is to provide enabling technologies ensuring that other departments in the Company function effectively and efficiently. In order to meet this objective, IT ensures that the Company's data is compatible with that available from industry; that data is accessible throughout the Company; and that information technology infrastructure platforms (Wide Area Networks, Local Area Networks, servers, desktops, laptops, printers, firewalls, anti-virus and intrusion detection services, etc.) are managed across departments. These platforms are designed to enhance the productivity and effectiveness of business processes, as well as meeting security requirements. Adequate security is critical to ensuring that business processes, employees, and customers are protected.

IT is also responsible for the life-cycle management of all business applications. Working with other departments, IT assists in the development of business cases, leads in the acquisition of resources (both financial and personnel), and in the designing, building, testing and implementation of business systems. Life-cycle-management responsibilities also include ensuring that business applications operate reliably. Finally, IT is responsible for the Company's overall IT strategy which incorporates the need for business applications and the underlying infrastructure required to support these applications.

(b) Facilities

The Facilities department ensures that the Company and its employees have a suitable work environment with safe and efficient buildings and workspaces. The Facilities department is responsible for acquiring and maintaining facilities throughout the Province. This department also processes, services, and manages the Company's requirements for office furniture and equipment, workspace changes and moves, and building security.

(c) Operations Engineering

The Operations Engineering department provides a variety of services necessary in support of Terasen Gas' operations. The services include:

- Engineering Design provides design services and operational support for all Transmission and Distribution pipelines and above ground facilities.
- GIS and Engineering Drafting which are responsible for completing new mains and service construction drawings and as-built mapping, as well as detailed design drawings for engineering projects as required. The GIS department is also responsible for developing and maintaining the Geographic Information Systems ("GIS"), and maintaining the majority of the records for distribution and transmission facilities.
- System Integrity provides risk-based integrity management services related to operating plant and surrounding natural hazards, principally focused on material defect, corrosion, geotechnical and hydro-technical risks and manages the TPIP on behalf of the Transmission group.
- The Corrosion group operates and maintains the systems providing cathodic protection to operating plant.
- Property Services is responsible for managing all land rights and land tenure issues including property taxation, acquisition and disposal, leases, right of way agreements, and for supporting environmental reviews and First Nations negotiations.

- System Planning is responsible for the planning of the lowest cost system improvements for the gas distribution and transmission systems based on system hydraulics and for providing hydraulic scenario analysis for operational enquiries and project development.
- Location Records provides asset information for underground facilities, as requested through BC One Call.

(d) Operations Support

The Operations Support department is comprised of four separate departments: Measurement Services, Instrument Control Systems and Data Acquisition, Supply Chain Management and Mechanical Services. With offices distributed among several communities within British Columbia including Burnaby, Surrey and Penticton, the Operations Support department provides safe, reliable and cost effective field support services to the Distribution and Transmission operating departments. These Operations Support departments are staffed with highly skilled analysts, trades people and employees trained to offer technical analysis and field support services.

- Emergency Response includes activities associated with supporting the Operating departments to respond to emergencies in order to ensure public and employee safety. Such activities relate to supply of emergency materials and equipment and repair to the company's operating assets.
- Mechanical Services refers to the manufacture and repair of tools and equipment as required by the Operating departments.
- Supply Chain Management involves all activities related to managing the flow of materials, tools and equipment inventory throughout the company.
- Meter Fleet Management encompasses all activities related to maintaining the "health" of the fleet in a manner that is technically sustainable, financially optimal and compliant with all appropriate public policy. Included are meter services offered to third parties.
- Instrumentation and Data Acquisition involves the maintenance of instrumentation, control and data acquisition systems throughout the company's pipeline system. Included are activities associated with daily data validation, editing and estimation on behalf of the commercial and industrial customers who purchase their natural gas through a commodity broker.
- Radio Network Management refers to the management of all aspects of the mobile radio network deployed within the interior of British Columbia and the Lower Mainland. Included are all activities relating to ownership of repeater towers which have provided an additional source of third party revenue.

(e) Procurement

The Procurement group is responsible for assisting other departments in acquiring a variety of materials and services. They ensure that the appropriate processes are followed and appropriate agreements are in place when the Company acquires materials and services. They also assist the company with market research, knowledge and analysis and tender evaluations.

(f) Project Management Office

The Project Management Office is responsible for providing project management and professional services to execute capital projects for the Transmission Asset Management group. Once a capital project is approved by Transmission Asset Management, the PMO oversees the associated project planning, engineering design, procurement, fabrication, installation, commissioning and closing.

Each of the B&ITS departments discussed provide services which are essential to Terasen Gas' operations. The organizational structure of the B&ITS department facilitates efficient delivery of these support services. As the Company grows and information technology advances, having effective support services will become even more critical to the success of Terasen Gas.

(v) Human Resources and Operations Governance

The Human Resource and Operations Governance department consists of two major functional areas, Human Resources and Operational Governance. In Human Resources, the focus is on ensuring our hiring practices, labour relations strategies, development programs, total compensation programs, and the associated processes and systems that support them are effective and efficient and that our workforce, now and in the future, will be able to support the achievement of the Company's objectives and business plans. The focus of the Operations Governance department is to create, maintain and ensure compliance with policies for various aspects of the business.

The following is a discussion of the two departments, their primary responsibilities and how their activities contribute to the Company's commitment to provide a safe, reliable and cost effective service customers expect.

(a) Human Resources

The overall goal of the Human Resources function is to ensure that the Company's workforce, now and into the future, is of a quality and quantity to enable the achievement of the Company's business goals and objectives. The Human Resources department performs and provides different services in support of management of the Company's workforce. The services include HR Strategy and Advisory Services, Leadership Development, Employee Training and Development, Recruiting, Labour Relations, short-term and long-term Disability Management, Pension and Benefits, Compensation, Payroll, Employee Services, and Human Resources Information System.

(b) Operations Governance

Key to achieving Terasen Gas' commitment to Operational Excellence is to ensure the risks associated with its operations are effectively managed and minimized. To address this, Terasen Gas has an Operations Governance department comprised of three departments; Environment, Health and Safety ("EH&S"), Engineering Governance and Enterprise Risk Management.

The EH&S department is responsible primarily for overseeing and performing activities in support of Operations Governance requirements. The functions performed include:

- Business Continuity ensures that the critical elements of the business will continue to operate during a major event. Business continuity is a new area of concentration for Terasen Gas, and refers to the ability of an organization to remain viable and provide service and support for its customers before, during and after an event.
- Corporate Security ensures that security risk is assessed and managed in compliance with applicable legislation and good business practices in order to effectively manage and minimize risk.
- Emergency Preparedness ensures that emergency response systems comply with applicable legislation and good business practice, are regularly exercised to maintain employee knowledge and continuous improvement, and that risks associated with our operations are effectively managed and minimized.
- Environmental Affairs manages, monitors and reports on the performance of our Environmental Management System designed to ensure compliance with applicable legislation, Company policies, industry codes of practice, and sound business practices.
- Occupational Health and Safety manages, monitors and reports on the performance of the Safety Management System which is designed to ensure compliance with WorkSafe BC regulations, other applicable legislation, Company policies and sound business practices. This helps to ensure that employee safety risks associated with Terasen Gas' operations are effectively managed and minimized.
- Public Safety Awareness mitigates the risk of asset failure due to third party activity or a natural gas related incident on customer premises by raising awareness of the properties of natural gas,

what to do if a leak is suspected, and line location requirements prior to excavation through a variety of communications strategies.

The Engineering Governance department has overall responsibility for maintaining the complete set of policies and procedures required by Terasen Gas, providing oversight for incident investigations and coordinating the approval of new materials used in the gas system. Working closely with the EH&S department, the Engineering Governance department also provides audit protocols and direction for operational reviews that are completed on a regular basis.

The Enterprise Risk Management and Insurance department has full responsibility for the Insurance and Enterprise Risk Management functions for the Company, including insurance procurement, claims management and loss studies. In addition, the department provides a yearly update of principal risks facing the Company for management and Board reporting. This department also includes Fleet Services, which has responsibility for procuring, maintaining, insuring and managing the operating costs of a 600 vehicle fleet.

The structure of the Human Resources and Operational Governance department allows the Company to efficiently respond to the evolving workforce needs in support of the achievement of the Company's objectives and business plans and facilitates effective compliance with policies for various aspects of the business. To maintain effective stewardship, Terasen Gas will continue to place a high priority on all Human Resources and Operational Governance activities.

(vi) Finance and Regulatory Affairs

The Finance and Regulatory Affairs department consists of the Finance department and Regulatory Affairs department, which are responsible for providing a range of financial and regulatory services to various departments throughout the Company. We have organized the department’s activities into two major functional areas of focus, enabling the optimal delivery of the services for the benefit of customers and stakeholders.

(a) Finance

The Finance department in Terasen Gas is comprised of a Financial Performance department and a Financial Accounting and Reporting department. Tax Services, Treasury Services, Corporate Development, Financial Reporting and Internal Audit services that are required by Terasen Gas are provided by Terasen through the Corporate Services Agreement.

- The Financial Performance department is responsible for the areas of budgeting and forecasting, management reporting, performance measurement, and tracking of capital expenditures.
- The Financial Accounting and Reporting department is responsible for accounts payable, asset and depreciation accounting, and financial accounting for Terasen Gas, including accounting for gas revenues, deferral accounts, cash, debt and interest, taxes, account reconciliations and controls, and maintaining the accounts of continuing service charges and billing of inter-company charges. In addition to and in conjunction with Terasen's Corporate Financial Reporting department, this department has the responsibility for reporting the results of the gas utility companies, developing and implementing financial accounting policies and procedures, assisting in the implementation of new or changing GAAP, reviewing and maintaining general ledger accounts and maintaining compliance with regulatory reporting requirements in the financial records.

The Financial services have been delivered efficiently providing timely, accurate and useful financial and other information to meet various external and internal reporting requirements.

(b) Regulatory Affairs

Over the term of the PBR Agreement, regulatory and stakeholder requirements have increased and changed in response to the evolving regulatory and business conditions. An indicator of the increased regulatory requirements is the fact that filings with the BCUC, the National Energy Board, and the Alberta Utilities Commission have increased from 400 in 2005 to 500 in 2008. To respond to these requirements, the Regulatory Affairs department has organized itself where it is able to handle the increased requirements and yet continue to be proactively anticipating the future requirements of the customer, business, and stakeholders.

The Regulatory Affairs department is focused on the following responsibilities:

- Developing pro-active regulatory strategies in support of current and prospective regulatory initiatives and issues;
- Assisting the operating departments with regulatory process, stakeholder management, regulatory and industry research, and analytical support for projects and initiatives;
- Developing rate design (rate pricing) structures that are in alignment with cost structures;
- Managing Gas Tariffs related to applications for changes and new initiatives and ensuring implementation of rate changes;

- Managing regulatory relationships with the Commission and stakeholders on behalf of the gas utility companies; and
- Managing the gas utility companies' compliance with Regulations, Orders, Directives and Decisions.

By organizing itself as outlined, the Regulatory Affairs department is positioned well to proactively respond to current and future regulatory requirements.

(vii) President and CEO

The President and CEO's office is responsible for the overall management of the Utility and for providing the overall leadership to execute the strategic plan. This office ensures that resources are employed efficiently and effectively across all business departments to ensure that customers receive value in the rates they pay for the safe, reliable and efficient delivery of natural gas.

(d) Balanced Scorecard

The Terasen Utilities successfully uses a Balanced Scorecard approach to deliver on a series of key success measures, align its business activities and maintain its focus on Operational Excellence for the benefit of customers and its shareholder. Terasen Gas' Scorecard is made up of four categories comprised of 10 measures that describe and guide Terasen Gas' overall performance in meeting the goals and targets that are set annually. The 2009 Scorecard is outlined in Figure B-1-2 below.

Figure B-1-2: Balanced Scorecard Used in 2009

Terasen Gas Group 2009 Scorecard

		Target
FINANCIAL	1. Terasen Gas Group Net Earnings	$105.2 m
CUSTOMER	2. O&M per Customer	$238.09
	3. Base Capital	$116.5m
	4. Customer Satisfaction	*79.0%*
KEY PROCESSES	5. Credit & Collections	0.35%
	6. Execution Against Regulatory Priorities	*Revenue Requirement and Cost of Capital Applications*
		Challenge
EMPLOYEE	7. Recordable Vehicle Accidents	39
	8. Recordable Injuries	31
	9. Wellness	5.6
	10. Public Safety	*Service Quality Indicator Results*

Ahead | On Track | Needs Attention | Needs Action

The four categories include Customer, Key Processes, Employee and Financial. In addition, the Scorecard serves as a valuable communication tool used to describe in clear and objective terms success measures for the companies while at the same time serving to demonstrate the companies' strong performance to its customers, regulator, and stakeholders. The Company has regularly described the Scorecard at the Annual Review workshops required under the terms of the PBR Agreement. The 2009 scorecard measures are described below.

Financial

Net earnings for the Terasen Gas group of companies is used as the financial performance measure taking into account earnings from its revenues, operating and maintenance expenses, depreciation, amortization, property taxes, interest expense and income taxes.

Customer

There are three measures related to the Customer on the Terasen Gas Scorecard including O&M per Customer, Base Capital and Customer Satisfaction. Effective management of costs is an important customer scorecard measure. This includes managing O&M on a per customer basis and capital expenditures (excluding CPCNs). Success in meeting customer expectations is measured through the use of an index score derived from surveys that measure customer opinions of Terasen Gas and the services provided to its residential, large commercial, builder/developer and small commercial customers. Billing, corporate image and marketing communications are tracked as they are the three most important customer satisfaction drivers for residential customers.

Key Processes

Key Processes consists of business processes that support, Credit and Collections that help control bad debt and Execution Against Regulatory Priorities. Credit and Collections is measured by the companies' ability to manage its residential and commercial customers' bad debt experience. Execution Against Regulatory Priorities is a new measure added in 2009, highlighting the importance of achieving success on regulatory issues and agreements, for the benefit of the companies' ratepayers and its shareholder. Previously, we included new customer additions as a measure on the Scorecard. While customer additions is still considered an important measure of our success, it has been removed as a standalone measure on the Scorecard as it was decided that some of the other Scorecard measures such as Net Earnings, O&M per customer, Base Capital and Customer Satisfaction capture the importance of the customer and growth.

Employee

Employee and public safety is a fundamental component to the companies' focus and commitment on Operational Excellence. The Employee measure encompasses four components and includes Recordable Vehicle Accidents, Recordable Injuries, Wellness and Public Safety. Scorecard challenges for employee injuries and vehicle accidents attempt to encourage employee behaviours that all accidents are preventable and that no accidents are acceptable. Wellness is measured as a composite of annual days lost per employee and is intended to promote improved attendance at work for employees. Achievements in Public Safety is measured by giving due regard to the safety metrics in the companies' Service Quality Indicators.

The use of the Scorecard has served Terasen Gas well in the past as it has proven to be a powerful tool in terms of improving organizational alignment and has helped to focus our activities on key measures that matter most.

(e) Summary of Management Excellence over the PBR Period

Terasen Gas is committed to Operational Excellence for the benefit of customers and shareholders. Through a strong corporate governance structure along with clear division of management responsibilities and well defined policies and procedures, Terasen Gas has taken the actions necessary, demonstrating our commitment to Operational Excellence. The efficiencies achieved to date including the USP project provide evidence of management's excellence and the effectiveness of the management structure and constructs in place.

While the needs of our customers and shareholder will continue to evolve, Terasen Gas believes the management structure and processes currently in place will provide a solid foundation to ensure the delivery of safe, reliable and cost effective service to customers.

Following is a discussion of Terasen Gas' past accomplishments in each of the Scorecard's four categories.

(2) CUSTOMER SERVICE OVER THE PBR PERIOD

Over the PBR Period, customers of Terasen Gas have reported increasing levels of customer satisfaction. At the same time, customers also saw delivery rates hold steady when compared to inflation. All of this has been accomplished in a period where overall demand for natural gas has declined, the rate of customer growth has declined (especially in the latter years of the PBR Period), and the expectations of customers have evolved. Terasen Gas has experienced success over the PBR Period in meeting needs and expectations of our customers through the introduction of new programs. We provided service that generally met, and in some cases exceeded, many SQI targets, while at the same time maintaining stable delivery rates.

The following sections describe how we have maintained a stable customer delivery rate and met customer needs for service, including SQI metrics, despite the annual demand for natural gas and rate of customer growth declining over the PBR Period. This is followed by discussions on how Terasen Gas has interacted with customers during the PBR Period, including discussions of three of the more significant regulatory applications related to improving customer service: the Energy Efficiency and Conservation Application; the Commodity Unbundling Application; and the System Extension Test. We consider it to be imperative to not only maintain existing service levels but also to expand and improve upon customer service activities and to develop alternative energy solutions to meet the evolving expectations of customers, policy makers and other stakeholders.

(a) Gas Delivery

This section provides an overview of the demand for natural gas, comprised of natural gas sales and transportation volumes over the period 2003 through 2009. Demand for natural gas is a key factor in determining rates as changes in volume impact the effective rate per GJ paid by customers. If the revenue requirement remains static and volume drops there will be upward pressure on delivery rates. Conversely, if volume increases there would be downward pressure on rates.

Demand is driven by the number of customers and average use per customer. Over the PBR Period, we have seen a growth in the number of customers, but a decline in the rate of growth in the latter years. At the same time, average use per customer has decreased as a result of the housing mix, changing appliance stock and a drive to more efficient appliances. Together, the impact of these trends has resulted in a reduction in total demand and has caused upward pressure on delivery rates. However, due to prudent management of costs, delivery rates over the period have remained virtually stable in nominal dollars. In real dollars, delivery rates have actually decreased over the PBR Period. This demonstrates the Company's commitment to continuous improvement and Operational Excellence as well as the effectiveness of the PBR regulatory model that Terasen Gas has operated under over the last six years.

The following section further explains the drivers for natural gas demand over the PBR Period.

(b) Demand and Customer Growth 2003 – 2009

Since 2003, our company has connected 56,324 new customers to its system, an average growth rate of 1.4 per cent per year. At the same time, more efficient home and appliance standards have been adopted, and we have experienced a continued shift towards more multi-family dwellings in the housing mix. Overall, the growth in customers has not offset the decline in average use per customer, which has resulted in a decline in overall energy demand. This section describes the differences in number of customers, average use per customer, and total energy demand over the PBR Period.

(i) Customer Growth

The rate of growth seen in our customer base reached a high in 2005 of roughly 12,000 customers, but it has been steadily declining since. The projection for 2009 is for approximately 6,000 customer additions. Customer additions are highly correlated to the housing market, influenced both by the number of household formations and also the housing mix (discussed in more detail in Part III, Section C, Tab 4). Customer additions are one of two key drivers in the demand for natural gas (with average use per customer being the other key driver). Customer additions are also a primary driver for capital expenditures as discussed in Part III, Section C, Tab 9. This decline in the growth rate of customers has had a significant impact on the operations of the Company, which has been managed effectively through the PBR Period.

Customer growth is measured by first determining the total number of meters installed on our system over a particular period. This measure is known as our gross customer additions. We then consider the level of customer turnover, which is the total number of customer that have left our system less those that have returned to the system for various reasons (including lock-offs due to arrears, vacant premises becoming occupied, seasonal customers returning, etc.). Adjusting our gross additions by the level of customer turnover yields the net customer additions, which represent the net growth in our customer base over that time period.

The following Table B-1-1 illustrates the historic customer additions, total customers, and also housing starts over the period 2003 through 2008 and the projection for 2009.

Table B-1-1: Net Customer Additions[1] Have Been Steadily Declining Since 2005

	2003 Actuals	2004 Actuals	2005 Actuals	2006 Actuals	2007 Actuals	2008 Actuals	2009 Projected
Residential[2]	6,306	10,716	11,427	9,595	9,277	7,959	5,213
Commercial[3]	(762)	756	1,002	655	694	1,294	907
Industrial & Transportation[4]	2	32	(9)	(69)	(56)	(6)	5
Total Net Additions	**5,546**	**11,504**	**12,420**	**10,181**	**9,915**	**9,247**	**6,125**
Total Gross Additions	**12,837**	**15,549**	**12,770**	**13,338**	**15,533**	**14,566**	**9,600**
Year-Ending Customers	775454	786,958	799,378	812,683[4]	822,598	831,845	837,970
Housing Starts[5]	24,050	32,925	34,667	36,443	39,195	34,321	22,800

Notes
1. Includes Lower Mainland, Inland, Columbia and Revelstoke service regions only.
2. Rate 1
3. Rates 2, 3 & 23
4. Rates 4, 5, 6, 7, 22, 25 & 27
5. Source: CMHC
6. Includes 3,124 additional customers due to amalgamation of Squamish customers

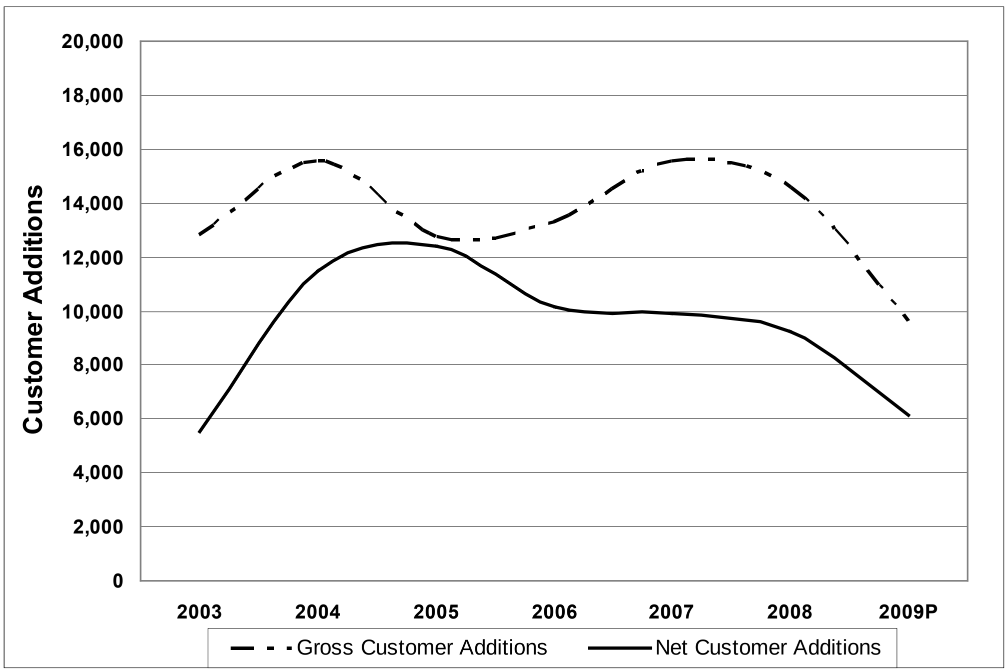
Further details of historical information are included in Appendix D-1: Consumption History.

During the five year period 2003 through 2008, we have added over 53,000 net customers, an average growth rate of 1.4 per cent per year, or approximately 10,600 customers per year on average. The projection for 2009 is slightly more than 6,100 or approximately 58 per cent (6,100/10,600), a significant decline from the first five years of the PBR Period. The vast majority (48,700) of those net customer additions were in the residential sector, although there were also 4,600 net commercial customer additions and also a loss of 115 industrial and transportation customers over the period.

(a) Gross and Net Customer Additions

As discussed above, customer growth is measured both in terms of gross and net customer additions. It is important to consider both gross and net customer additions, because they drive key areas of our business such as the O&M and Capital costs incurred through serving our customers. The following Figure B-1-3 illustrates the historical gross and net customer additions over the period 2003 through 2008, and the projection for 2009.

Figure B-1-3: Historical Gross and Net Customer Additions Declining since 2007



Although the growth patterns of gross and net additions are not identical, they have both declined since 2007. Gross customer additions are primarily influenced by macroeconomic factors such as the housing market and relative competitiveness of natural gas, whereas net customer additions are also influenced by customer behaviour (changes in bad debt, lock-offs, etc.).

Over the period 2003 through 2008 we have experienced an average of 14,100 gross customer additions per year, ranging from a low of 12,770 in 2005 to a high of 15,533 in 2007. The current trend, consistent with the housing market, is for a continued softening of the market potential.

Net customer additions have averaged 9,800 per year over the period 2003 through 2008. Net customer additions have grown from a low of 5,546 in 2003 to a high of 12,474 in 2005, but have since been declining. The decline in net customer additions relative to gross customer additions is attributed to the slowdown in the housing market, and also increased customer attrition, which is discussed in Part III, Section C, Tab 4.

Although gross and net additions have experienced growth over the past six years, with expectations for a dramatic decline in the housing market, the forecast of gross and net customer additions in 2009 is at similar levels as seen in 2003.

(ii) Average Use Per Customer

Average use per customer is the other key driver in the demand for natural gas. Average use per customer has declined steadily over the period 2003 through 2008 for residential customers, whereas commercial average use per customer has been relatively stable. As discussed in greater detail in Part III, Section C, Tab 4, average use per customer is influenced by a number of factors, including the retrofit of higher efficient appliances, the housing mix, and also government policies and programs aimed at improving efficiencies. In the event that demand from customer additions does not offset the reduction in demand due to declining use rates, a decline in total demand would result. Although this places upward pressure on delivery rates for our customers, they may still benefit from lower heating bills.

The following Table B-1-2 illustrates the historic normalized actual average use per customer for our residential and commercial customers over the historical period 2003 through 2008 and the projection for 2009.

Table B-1-2: Normalized Actual Average UPC (GJ/yr) is driving the decline in overall demand

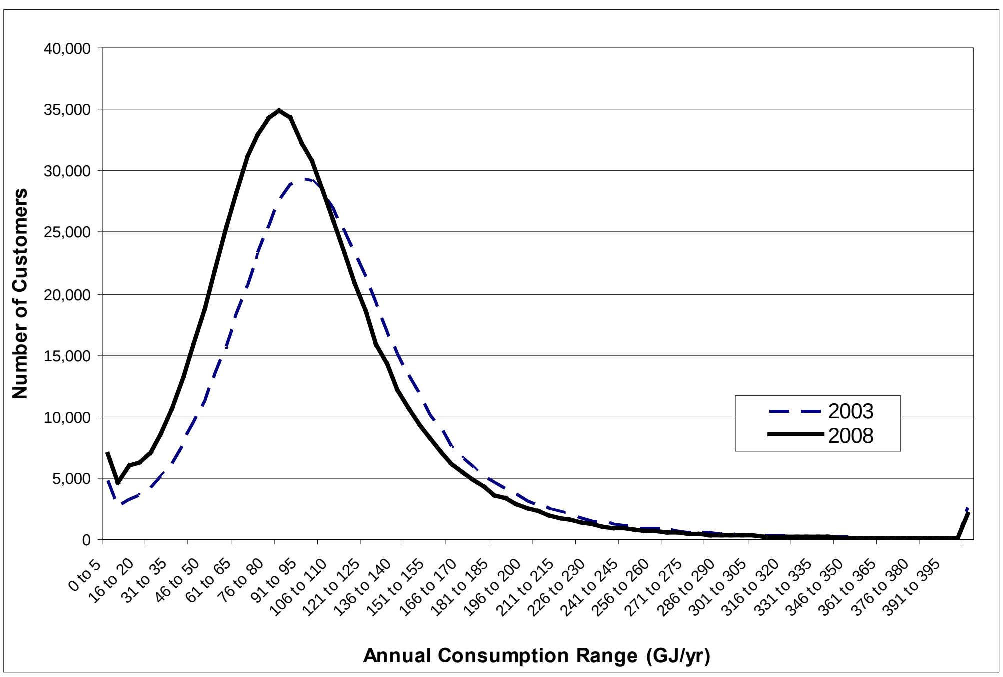
	Normal 2003	Normal 2004	Normal 2005	Normal 2006	Normal 2007	Normal 2008	Projected 2009
Rate 1	103.1	102.6	97.4	96.8	96.0	92.5	94.6
Rate 2	304	314	306	314	317	326	323
Rate 3	3,292	3,501	3,388	3,314	3,426	3,406	3,427
Rate 23	4,883	5,113	4,714	4,686	4,778	4,642	4,830

Further details of historical information are included in Appendix D-1: Consumption History.

Although residential use per customer has declined by 10.6 GJ from 2003 to 2008 (an average decline of 2.1 per cent per year), small commercial use per customer has increased by 22 GJ (an average of 1.4 per cent per year) and large commercial use per customer has increased by 114 GJ (an average of 0.7 per cent per year). Commercial transportation use per customer has also declined, by 241 GJ or an average of 1.0 per cent per year. Average use per customer is the most significant variable in determining total energy demand, and the change seen in average use per customer for residential and commercial customers from 2003 through 2008 is the primary driver of the 3 per cent decline seen in overall energy demand for residential and commercial customers over this period.

Over 90 per cent of the company's customer additions since 2003 have been in the residential sector. This, combined with the shift towards more multi-family dwellings in the housing mix, a growing focus on energy efficiency, an erosion of the competitiveness in natural gas (in relation to electricity), and also a change in public perceptions towards fossil fuels has led to a change in the profile of our residential customers. The following Figure B-1-4 illustrates the distribution of annual consumption for our residential customers.

Figure B-1-4: Residential Consumption is Declining

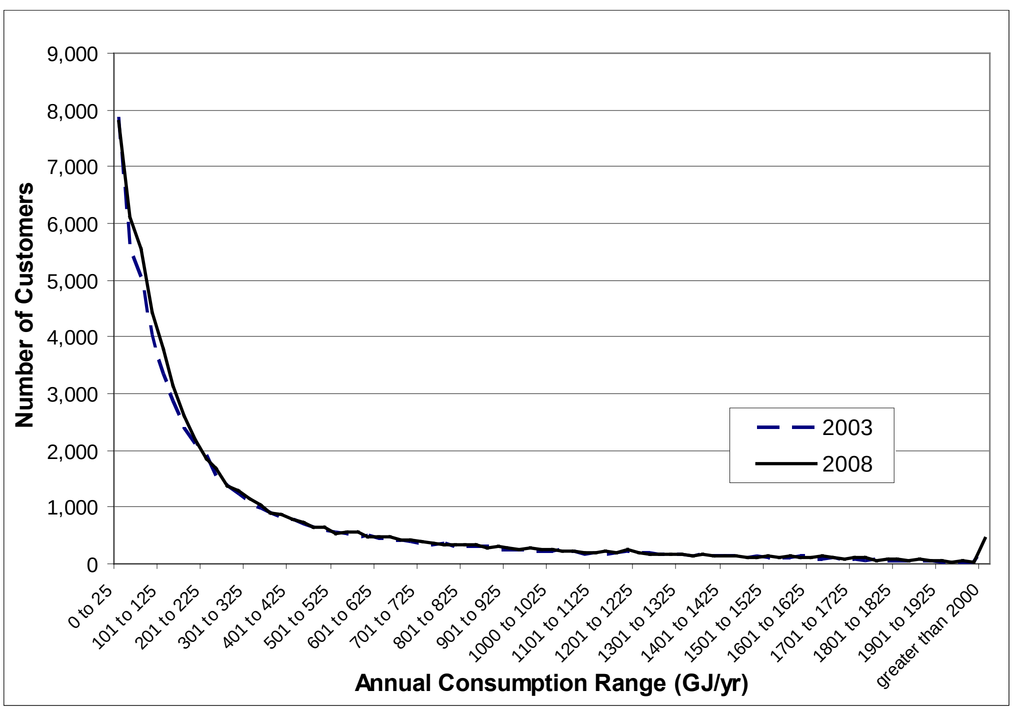


It is easily inferred from the above table that residential consumption is declining. Two general observations can be made from Figure B-1-4: 1) There are now fewer customers consuming more than 100 GJ per year; and, 2) There are more customers consuming less than 100 GJ per year.

The decrease in the number of customers consuming more than 100 GJ per year is primarily attributed towards efficiency improvements, more specifically the replacement of older, less efficient appliances with newer high efficient units. The increase in the number of customers consuming less than 100 GJ per year is also attributed towards efficiency improvements, but the shift towards more multi-family dwellings in the housing mix is also impacting this group of customers. It is reasonable to expect the profile of residential customers to continue shifting towards a declining residential use per customer. The drivers of this expected shift are: a continued shift towards more multi-family dwellings in the housing mix, building code changes, and also demand side management efforts.

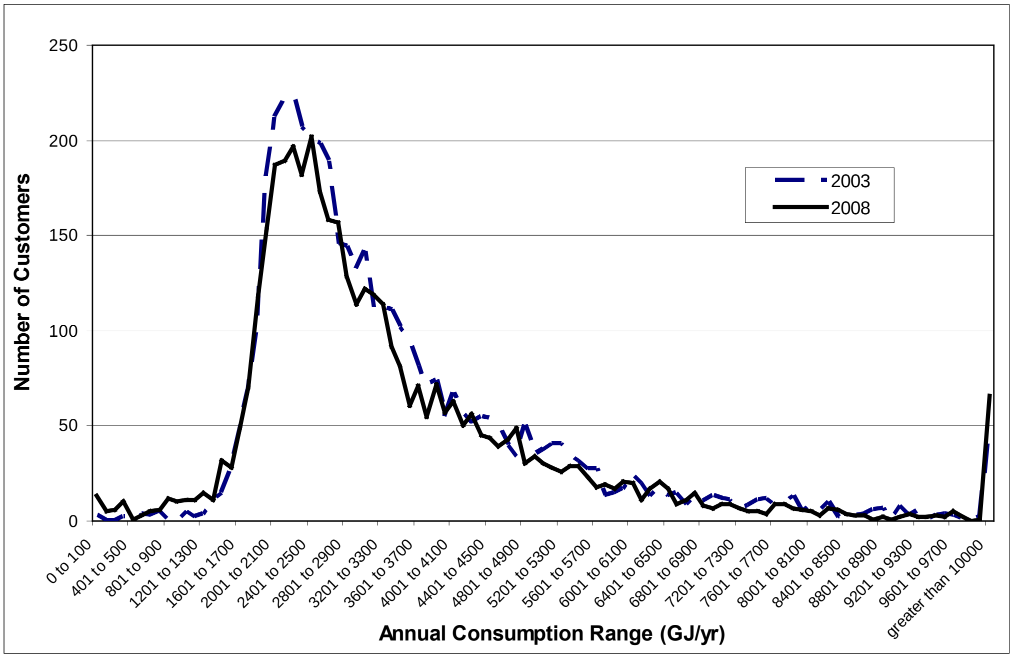
With less growth seen in the commercial sectors, and also the average use per customer being more stable since 2003, it is not surprising to see the profiles of both small and large commercial customers have not changed to the same extent as residential customers. The following Figures B-1-5 and B-1-6 illustrate the profile of annual consumption for small and large commercial customers.

Figure B-1-5: Small Commercial Customers Annual Consumption Profile – Virtually no Change



As the above graph illustrates, there has been virtually no change in the annual consumption profile of our small commercial customers over the period 2003 through 2008.

Figure B-1-6: Large Commercial Customers Annual Consumption Profile – No Significant Change



As illustrated above in Figure B-1-6, the annual consumption profile of our large commercial customers has not changed significantly between 2003 and 2008. The differences seen are attributed to the fact that in 2008 there were approximately 500 fewer customers than there were in 2003. Overall, there is no significant difference in the large commercial annual consumption profile from 2003 to 2008.

(iii) Total Energy Demand

Overall energy demand is a function of both customer additions and average use per customer. As the majority of the revenue collected by the Company from customers is based on variable rates, total energy demand will have a direct impact on rates. A decline in total demand, all else equal, will cause upward pressure on rates, while at the same time customers may benefit from lower heating bills. The following Table B-1-3 illustrates the historic demand, by sector, from 2003 through 2008, and the projection for 2009.

Table B-1-3: Historic Total Demand has been declining over the PBR Period

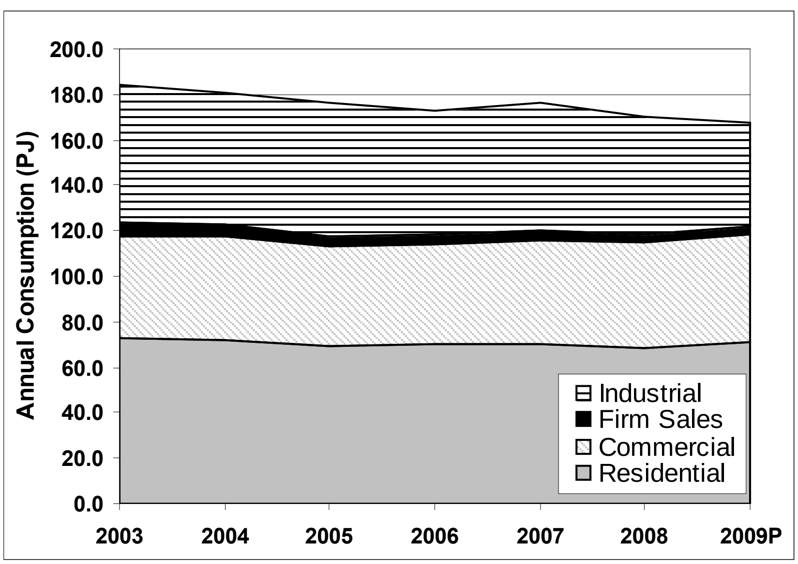
	Normal 2003	Normal 2004	Normal 2005	Normal 2006	Normal 2007	Normal 2008	Projected 2009
Residential[1]	72.6	72.0	69.3	70.0	70.6	68.8	71.0
Commercial[2]	45.3	45.2	43.9	44.1	45.5	45.9	47.5
Firm Sales[3]	6.1	5.3	4.7	4.1	3.8	3.5	3.4
Industrial[4]	60.1	58.3	58.6	54.2	56.3	51.8	45.2
Total	**184.1**	**180.8**	**176.5**	**172.4**	**176.2**	**170.0**	**167.3**

Notes
1. Rate 1
2. Rates 2, 3 & 23
3. Rates 4, 5 & 6
4. Rates 7, 22, 25 & 27 (does not include Burrard Thermal & TGVI)

Further details of historical information are included in Appendix D-1: Consumption History.

The residential sector has experienced a decline in total energy demand of approximately 1.1 per cent per year from 2003 through 2008, with customer growth only partially offsetting a greater decline in average use per customer. The firm sales and industrial and transportation sectors have declined at a greater rate (2.5 per cent and 10.6 per cent respectively) over the same period. The commercial sector has been relatively stable, with 2008 demand only 0.6 PJs higher than it was in 2003, an increase of just 0.3 per cent annually. These changes are also illustrated in the following Figure B-1-7.

Figure B-1-7: Changes in Annual Demand by Customer Segment



The changes in annual consumption in each of our customer segments, as illustrated above, have resulted in an overall decline in energy demand of 7 per cent (or 1.4 per cent annually), from a high of 182.8 PJs in 2003 to 170.0 PJs in 2008.

Over the PBR Period the Company has seen a decline in total energy demand. As can be seen in Figure B-1-7 above, this has been primarily driven by declines in the firm sales and industrial and transportation customer segments. And given current economic conditions, it is likely that these trends will continue. The residential and commercial segments, although proving more stable in terms of total energy demand over the PBR Period, are highly influenced by more recently emphasized energy efficiency efforts and also a continuing shift in the housing mix. With these trends expected to continue, it is reasonable to conclude that total energy demand will continue to decline.

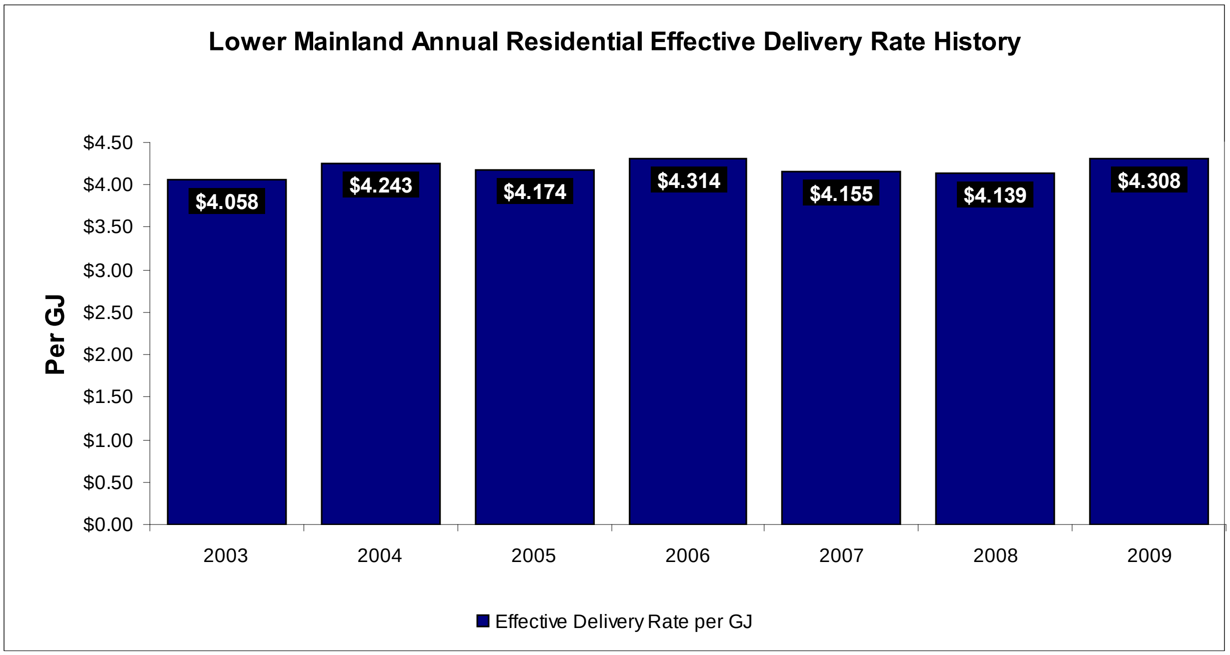
(iv) Delivery Rates

As has been discussed in the previous section, reduction in natural gas demand, all things being equal, will result in increasing rates. Due to prudent and responsible management through its commitment to continuous improvement and Operational Excellence, Terasen Gas has been able to ensure that the delivery rates are not only transparent but have remained very stable in nominal dollars over the PBR Period. As the table below demonstrates, the effective nominal delivery rate for Lower Mainland customers in 2004 was $4.243 per GJ and the effective delivery rate in 2009 is $4.308 per GJ, an increase of only $0.065 per GJ. In fact, in real dollar terms, delivery rates over the term of the PBR Period have actually decreased. Therefore, customers are paying less for delivery services since they are using less energy and the unit cost has declined in real terms. Terasen Gas believes that this demonstrates the success of the PBR Agreement and our commitment to it.

The components of the delivery rates were updated each year during the PBR Period. The components include the basic charge, base delivery rate, as well as rate riders for the ESM and the Revenue Stabilization Adjustment Mechanism ("RSAM"). Changes in the basic charge and base delivery rates reflected the annual cost of service updates as outlined in the Settlement agreements and were examined and tested as a part of the annual review process each year. The ESM delivery rate rider passed on the customers' share of the Company's cost saving success from the previous year to all Terasen Gas customers. The RSAM delivery rate rider, applicable to Rate Schedules 1, 2, 3 and 23, provided the benefit of smoothing out fluctuations in rates that would have occurred as a result of customer usage that was different than what had been forecast. While this is a complex set of changes, collectively, the effect of these changes has been very stable delivery rates over the PBR Period.

The following table provides a summary of the effective delivery rate from 2003-2009 for Lower Mainland Residential customers and demonstrates the stability in delivery rates throughout the PBR Period. This similar pattern is also seen in other rate classes and service areas.

Figure B-1-8: Stable Effective Lower Mainland Residential Customer Delivery Rates 2003-2009[99]



Assumes:
Natural gas use of 95 GJ
Terasen Gas effective rate includes basic charge and riders

(c) Customer Related Activities

The Marketing Department of Terasen Gas serves as the primary interface with the public and customers. It is through activities such as billing, meter reading, communications and advertising, and government relations that the customer often interacts and gains its impression of Terasen Gas.

Customers expect Terasen Gas to provide billing and meter reading services, educate and communicate with them at regular intervals, and provide knowledgeable account management and sales functions. Customers also expect that Terasen Gas is advocating in their best interests with government. Lastly customers expect that Terasen Gas will be proactive in providing them with new services and updated rules for the provision of service to meet their needs. We have grouped these activities together into the following four sections for ease of explanation:

99 Effective rate includes basic charge, base delivery rate and all delivery rate riders and assumes a usage rate of 95 GJ per year

- Customer Care and Services:
  - Customer Service Metrics; and
  - Commodity Unbundling.
- Customer Information and Education.
- Customer Solutions and Services:
  - Energy Efficiency and Conservation;
  - System Extension Test; and
  - Advocating for Gas Customers in Regulatory Proceedings.
- Customer and Business Facilitation.

Through these functional areas, Terasen Gas has significant contact with customers. The following discussion outlines our successful interaction with our customers.

(i) Customer Care and Services

Customers rely on Terasen Gas for accurate billing, meter reading, efficient customer contact service agents and timely and efficient construction services initiation processes. Through the Customer Care and Services functional area of the Marketing department, Terasen Gas (i) manages relationships with its customers through outsourced meter-to-cash[100] activities with CWLP, including the provision of ongoing customer care to a diverse mix of customer types (ii) handles direct and BCUC customer complaints and customer issues, mass market bad debt management (discussed on page 171), market research and analysis including researching and assessing the energy marketplace and customer energy needs and monitoring and assessing the competitive position of our product offerings versus other energy alternatives, and construction services call centre activities, and (iii) manages the customer service satisfaction metrics. Collectively, the Customer Care and Services functional area of the Marketing department is responsible for the largest component of the Marketing budget. Terasen Gas believes it has provided good service levels to customers but recognizes there are opportunities for improvement in the outsourced meter-to-cash activities. To meet the evolving needs of customers, Terasen Gas believes that it is important to improve its level of customer service over the period of the RRA and has allocated additional resources to meet these needs, which will be discussed later in this Application.

[100] Meter to Cash includes customer services from the time the meter is installed at the original application to ongoing meter reading and billing through to the payment and collection process.

(ii) Customer Satisfaction Metrics

The 2004–2007 PBR Agreement (and 2008–2009 Extension Agreement) included a commitment to maintaining specified levels of service as measured by SQIs. Terasen Gas has ten SQIs that are measured and compared against benchmarks or historic performance on an annual basis. Additionally, there are two directional indicators that do not have benchmarks but are designed to give an understanding of trends that may develop in these particular areas relating to customer service. These SQIs were put in place to ensure that customer service levels were maintained following the introduction of incentives to manage operating costs. Terasen Gas is proud of its track record over the PBR Period in having met the SQIs with limited exceptions that are discussed below. Customers have therefore benefited by not only having stable rates as a result of cost control, but also strong customer service. We feel that this demonstrates that Terasen Gas has been, and continues to be, a trusted and respected utility operator.

Table B-1-4: Terasen Gas has Met SQI Targets over the PBR Period

	Performance Indicator	Benchmark	2003 Annual Actual	2004 Annual Actual	2005 Annual Actual	2006 Annual Actual	2007 Annual Actual	2008 Annual Actual	2003 - 2008 Average	2009 YTD April Actual
1	**Emergency Response Time** - Time Dispatched to Site - Emergency - Blowing Gas	≤21.1	22:00 minutes	21:36 minutes	21:42 minutes	21:30 minutes	20:36 minutes	20:42 minutes	21:35 minutes	22:00 minutes
2	**Speed of Answer – Emergency** (% of calls answered within 30 sec.)	≥95.0%	96.3%	97.9%	98.8%	98.6%	98.4%	98.3%	98.0%	98.5%
3	**Speed of Answer – Non-Emergency** (% of calls answered within 30 sec.)	≥75.0%	76.4%	77.5%	76.9%	78.2%	76.9%	73.8%	76.6%	76.8%
4	**Transmission Reportable Incidents**	≤2	3	3	3	1	1	2	2	0
5(a)	**Index of Customer Bills Not Meeting Criteria**	≤5	2.63	1.93	1.97	0.77	2.30	7.53	2.86	6.90
5(b)	**Percent of Transportation Customer Bills Accurate**	≥99.5%	99.8%	96.6%	99.9%	99.9%	99.5%	94.3%	98.3%	88.6%
6	**Meter Exchange Appointment Activity**	≥92.2%	92.6%	93.5%	94.3%	94.1%	93.5%	94.5%	93.8%	87.2%
7	**Accuracy of Transportation Meter Measurement First Report**	≥90.0%	97.4%	98.0%	99.5%	98.1%	98.9%	96.2%	98.0%	98.4%
8	**Independent Customer Satisfaction Survey**	Compared to prior years	73.9%	73.9%	77.2%	77.9%	79.3%	79.7%	77.0%	79.9%
9	**Number of Customer Complaints to BCUC**	Compared to prior years	101	191	121	152	130	90	131	21
10	**Number of Prior Period Adjustments**	Compared to prior years	24	18	14	21	23	15	19	11

	Directional Indicators	Benchmark	2003 Annual Actual	2004 Annual Actual	2005 Annual Actual	2006 Annual Actual	2007 Annual Actual	2008 Annual Actual	2003 - 2008 Average	2009 YTD April Actual
1	Leaks per Kilometer of Distribution Mains	N/A	0.0040 134	0.0045 150	0.0034 120	0.0021 76	0.0024 87	0.0016 57	0.0030 104	0.0009 17
2	Number of Third Party Distribution System Incidents	N/A	1,459	1,492	1,457	1,508	1,545	1,574	1,506	299

As is shown in the Table B-1-4 above, over the PBR Period, Terasen Gas has met SQI targets with the exception of 2008 Non-Emergency Speed of Answer, Customer Bills not Meeting Criteria and Percent of Transportation Bills Accurate. During 2008 and Q1 2009, Terasen Gas has experienced declining performance in key SQI measures that are delivered by Accenture Utilities BPO Services ("AUBPOS") under the contract with CWLP. We have also been challenged with the impacts of staff turnover in the AUBPOS Customer Advocacy group which is focused on addressing and resolving escalated customer issues including complaints to the BCUC. As a result of the ongoing nature of these challenges, we have found it is necessary for Terasen Gas to bring additional positions into our contract management team. This will enable a higher level of oversight, the appropriate level of ownership for key processes and build thorough process knowledge within a broader group at Terasen Gas rather than a small number of individuals.

The Customer Care and Services group oversees all of TGI's market research needs. Primary activities include four annual surveys that establish the company's customer satisfaction scores with residential and commercial customers, as well as the builder and developer segment that is a key to our future success. To address the rapidly changing energy use in modern homes, Terasen Gas is proposing to expand its analysis of how customers use natural gas. This type of analysis helps the utility improve its forecasting accuracy and assists in bringing marketing offers to customers that they find valuable. Other studies range from small focus groups to broad, web or phone-based research surveys designed to help Terasen Gas design and deliver new services and products that customers want from their natural gas provider.

The use of secondary research in the investigation of new trends and customer service expectations is of growing importance. Terasen Gas uses both primary and secondary research to evaluate emerging customer service options and customer expectations. As customer needs change ever more rapidly, it is evident there is an ongoing need for expanded consumer focused research at Terasen Gas.

(iii) Commodity Unbundling

In response to the Energy Plan of 2002 which states that "natural gas marketers will be free to sell directly to residential and small commercial natural gas customers",[101] TGI implemented unbundling for commercial and residential customers.

In April, 2004 the Commercial Unbundling phase was introduced by TGI for Rate Schedule 2 and 3 customers. This phase of the program was put in place to design business rules, and an IT platform that

101 See Appendix C-3 for a copy of Energy Plan 2002: Energy for Our Future: A Plan for BC, page 9

could serve as the foundation for the program to be leveraged for the residential marketplace. These business rules have come to be known as the Essential Service Model. Under this model, Terasen Gas is responsible for managing all midstream resources[102] in addition to fulfilling the role of supplier of last resort, as well as providing its regulated standard commodity rate offering to residential and commercial customers. Terasen Gas also performs all billing and customer care activities under this model. This made in B.C. solution addresses the B.C. supply infrastructure and market requirements for the effective implementation of commodity unbundling, giving consumers the ability to exercise choice while still reflecting the capacity constraints in the British Columbia marketplace.

By November, 2006, 13,687 commercial customers had signed with a marketer and were receiving a fixed price offering for the gas that they consumed. All business rules of the Essential Services Model were working as designed.

On April 13, 2006 Terasen Gas submitted a CPCN application to the BCUC to implement commodity unbundling service for residential customers in BC to be effective November 1, 2007. On August 14, 2006 the BCUC approved the application via Order No. C-6-06. The Essential Services Model and business rules approved were largely the same as the business rules that were used in the commercial phase of the program with some additions such as the customer confirmation letter, and moving to monthly enrollments from quarterly enrollments.

As of April 1, 2009 a total number of 139,630 customers have signed with a third party marketer. This total is broken down by 119,959 residential customers and 19,671 commercial customers. Again, as with the commercial program, all business rules and IT systems that were implemented for the residential Customer Choice program are working and performing as designed.

We believe that providing customers with commodity choice is a positive change to the natural gas market. We believe it is important to ensure that the commodity unbundling program is a success and that customers have the option to purchase from a marketer or Terasen Gas. We believe it is also important that for the integrity of the Commodity Unbundling program, the Essential Services Model must remain in place. Terasen Gas will continue to work with customers, stakeholders, marketers and the BCUC to ensure that customers continue to have customer choice options and to ensure that the integrity of the Customer Choice program continues

[102] Midstream resources are defined as transportation assets to move gas from supply hub to the Terasen Gas transmission system. Also includes storage assets to help shape the gas to match customer demand profiles.

(iv) Customer Information and Education

Terasen Gas provides customers with information and communications on Terasen Gas initiatives, rate changes, and programs in a timely and efficient manner. During the PBR Period, Terasen Gas has undertaken a number of initiatives to ensure its customers are provided with useful and relevant information that affects their use of natural gas. These efforts include: communicating the availability of the Company's energy efficiency programs; highlighting the lifestyle and environmental benefits of using natural gas; providing information on public safety (i.e. Gas odour detection and action, Call Before You Dig and seasonal safety messages); publicizing the companies Equal Payment and Pre-Authorized Payment plans; and informing customers of gas rates and pricing. Customer Choice education enhancements to Terasen Gas' website content and navigational structure also contributed to make the site more user-friendly, easier and faster for customers to find information.

In addition to communications to customers, public awareness and involvement materials have been developed to support the Whistler Pipeline Project and the Mt. Hayes Natural Gas Storage Facility development. Materials produced are designed to create awareness, provide updates about projects and promote opportunities for public involvement. We are of the view that our communications efforts with stakeholders, communities, and customers played a significant role in the efficient regulatory process and ultimate CPCN approvals of these projects.

Customer Information and Education is integral to the success of Terasen Gas as it provides customers, stakeholders and internal users access to information regarding Terasen Gas. This is evidenced by the success of CPCNs, customer awareness of programs such as customer choice and low number of BCUC customer complaints. It is our belief that as customer needs continue to change, we will require additional resources to meet our customer's communication requirements.

(v) Customer Solutions and Services

Commercial and Industrial customers look to Terasen Gas for account management and contact, developers expect Terasen Gas to be available and to meet all their gas service (and recently alternative energy) needs, and customers also expect Terasen Gas to look for opportunities to expand their business so as to be able to provide a wider range of services and programs. Customers also expect Terasen Gas to lead energy efficiency and conservation efforts, to accurately forecast usage and lastly to advocate on their behalf in regulatory proceedings. The Customer Solutions and Services group works on behalf of customers to meet these needs. Through proactive efforts, we have been successful in providing customers with unique service offerings such as tariff supplements, ensuring that our customers' voice is heard in regulatory hearings and ensuring that new customers are added in an efficient manner. Over the course of the PBR Period, activities and successes in these groups included:

- Residential, Commercial and Industrial Tariff offerings including:
  - Thermal Metering, Rate Schedule 7, 10, 14 and 14A filings, Piping to Suites;
  - Industrial Tariff Supplements for customers including:
  - Westport Innovations Inc., Husky, Tembec, Dunkley Lumber Inc., Fording Coal, and Central Heat Distribution Inc.;
- LNG Tariff Application, TGVI LNG CPCN (for which TGI will be a customer) and approval;
- Participation in over a dozen government energy efficiency, code and other working groups;
- Sales solutions provided to architects, developers and engineers to include gas in building developments such as:
  - Sahali Ridge Estates – 64 unit townhouse project in Kamloops ;
    - High efficiency furnaces, Direct vent water heaters, Fireplaces, BBQ's, Ranges (optional);
  - The Rock – 60 unit townhouse project in Vernon;
    - High efficiency furnaces, Fireplaces, BBQ's;
  - Mission Hill – 5 building condominium in Kamloops (44 units each). 2 buildings currently under construction (88 units in total); and
    - 88 Instantaneous water heaters (combo units), 88 BBQ's, 44 Ranges, 44 Fireplaces;
- Intervention in BC Hydro Rate Design Application ("RDA") proceeding, Long Term Acquisition Plan ("LTAP") and Revenue Requirement proceedings.

Terasen Gas is proud of the accomplishments of the past five years. In the years to come, however, customer driven expectations will only increase. As previously noted in Part III, Section A, changing customer requirements driven in part by a changed government policy environment has changed the context in which Terasen Gas provides Customer Solutions and Services to its existing customers. This will require additional sales and account management staff to meet customer expectations.

(vi) Energy Efficiency and Conservation

Terasen Gas has had in place DSM programs since the mid 1990's. Through Commission Order No. G-85-97 Terasen Gas received approval to pursue DSM initiatives. At that time the DSM expenditure levels for incentive and grants was set at $1.5 million, with a similar amount for O&M spending. Terasen Gas enjoyed a measure of success with its DSM programs from 1997-2008. However, we believed that more could be done to encourage DSM activities. On May 28, 2008, TGI and TGVI filed their EEC Programs Application, for funding of EEC programs for the 2008-2010 three year period. The application requested approval for a total of $56.6 million (for both TGI and TGVI collectively), capital treatment and a amortization period of 20 years, and a portfolio methodology for evaluating the costs and benefits of the overall EEC portfolio. On April 16, 2009, TGI and TGVI received BCUC Order No. G-36-09 which approved funding in aggregate of $41.5 million for the three year period, capital treatment of all expenditures with an amortization period of 10 years, and approval of a portfolio approach to evaluating the costs and benefits of the overall EEC portfolio.

While the Companies did not receive approval for expenditures for innovative technologies as part of the EEC application, through the RRA, we are proposing specific Innovative Technologies programs that we believe meet the Commissions directives in Order No. G-36-09. Since the time of the original application, Terasen Gas has also had the opportunity to further assess opportunities for an interruptible Industrial EEC program. This Application addresses the Commission's direction to commence a planning process for the development of an Industrial EEC program. In addition we have already been working to re-allocate funds to low income programs from other programs.

Approval of this EEC funding was a large step forward in improving Terasen Gas' ability to promote energy efficiency and for customers to realize the benefits of energy efficiency and conservation. However, Terasen Gas believes that there is room for additional EEC programs and which are discussed later in the RRA. Terasen Gas believes that the EEC programs are at the core of its strategy to reduce emissions, promote the efficient use of gas, and to encourage the adoption of low carbon energy alternatives.

(vii) System Extension and Connection Policy Review

During the PBR Period, TGI and TGVI applied to the Commission to change and update their System Extension and Connection Policies. We believed that the test and policies in their previous form did not send the right signals to customers wishing to attach to the system and could therefore also negatively impact existing customers. As a result of the approval of the System Extension and Connection Policy Review application, customers would:

- have a test that signals better value for those wishing to attach to the system;
- have policies and processes that ensure that the system extension test measures the right factors, be simple to understand and administer with results that send the appropriate economic signal to the customer; and
- be encouraged to conserve energy through the test and attachment policies.

Commission Order No. G-152-07 approved the following items:

- Elimination of the $215 Service Line Installation Fee;
- Increasing the Service Line Contribution Allowance to $1535;
- The continued use of the Main Extension Test to determine economic profitability;
- An individual Profitability Index ("PI") of 0.8 and an aggregate system wide PI of 1.1; and
- An increase in GJ amounts, within the MX Test, for high efficient appliances to encourage energy efficiency.

Terasen Gas believes that these changes resulted in more appropriate price signals to customers reducing the disincentives to attaching to the Terasen Gas system. Terasen Gas expects to achieve incremental customer connection activities as a result of the System Extension and Connection Policy Application approval in the years to come.

(viii) Advocating for Gas Customers in Regulatory Proceedings of Others

Customers should be able to expect Terasen Gas to advocate on their behalf in the regulatory proceedings of other utilities and upstream pipelines and storage service providers. The main areas in which Terasen Gas performs this advocacy role are in National Energy Board ("NEB") and Federal Energy Regulatory Commission ("FERC") - regulated entities with respect to the midstream and gas supply areas and BCUC-regulated entities for competitive concerns at the customer level. These advocacy roles have contributed value to natural gas customers by reducing costs Terasen Gas may pay to other companies for service.

Terasen Gas staff participates in the NEB and FERC proceedings of transmission pipelines and storage service providers to promote the interests of natural gas customers in BC. Natural gas customers have been protected in the commodity and mid-stream portions of their natural gas bills by virtue of lower pipeline transmission tolls due, in part, to the Terasen Gas interventions and leadership role in toll settlement discussions to ensure fair and reasonable cost allocation and rates principles are implemented.

Terasen Gas also promotes the interests of natural gas customers in BC through its intervention in the regulatory proceeding of other utilities in BC. The advocacy role in this area has been most commonly expressed over the last five or six years through involvement in BC Hydro's regulatory proceedings. Electricity rates in BC are bundled rates, including the components of generation, transmission, distribution and customer-related costs. By comparison, natural gas rates in BC are unbundled with separate charges for commodity, mid-stream and distribution/customer-related costs. Natural gas commodity prices are market-driven and fluctuate with the typical conditions of market supply and demand. BC Hydro's bundled electricity rates, on the other hand, mask the fact that most of BC Hydro's electricity supply is from low cost Heritage generation facilities while new electricity supply acquired to meet growing load requirements is much more expensive than the Heritage electricity. TGI's interventions in BC Hydro regulatory proceedings are aimed at promoting efficient utilization of the energy infrastructure in the province and ensuring that the right price signals are in place so that customers are not incented to leave gas, thereby leaving higher delivery rates for remaining customers. Terasen Gas has been an active intervenor in many of BC Hydro's regulatory proceeding since 2004, most notably, the 2006 Integrated Energy Plan, the 2007 RDA, the 2008 RIB application the 2008 LTAP, and the Revenue Requirement application.

An important example of this advocacy role in BC Hydro proceedings is Terasen Gas' intervention in the 2007 RDA. In its Decision the Commission commended Terasen Gas for raising certain issues with respect to the impact of space and water heating on BC Hydro's load growth in the peak winter season.[103] The Commission Decision on the 2007 RDA also required BC Hydro's cost allocation approach in its cost of service study to be more reflective of the winter peaking nature of the BC Hydro system and therefore, in keeping with principles of cost causation, to recognize that more of the total cost of service is attributable to the residential class. This directive and others in the 2007 RDA Decision, such as requiring BC Hydro to come forward with a Residential Inclining Block rate application, may over time help to ensure the proper price signals between gas and electricity rates.

(ix) Customer and Business Facilitation

Maintaining relationships with customers through community activities, and maintaining relationships with municipal and provincial governments have resulted in a benefit to all Terasen Gas customers. Activities in this area are crucial to ensuring that Terasen Gas is able to carry on its business in communities and the areas it currently serves. The Customer and Business Facilitation group manages the relationships with all levels of government regarding ongoing operations, analyzes, interprets government policies that impact our business, and also provides input to government policies that may impact our customers. This group also liaises with business groups and non-governmental organizations that represent our customers including chambers of commerce. In addition, the Customer and Business Facilitation group helps to conduct customer and stakeholder consultations for new projects. Through community involvement, and regular consultation with municipal, regional, provincial, federal and First

[103] BC Hydro 2007 Rate Design Decision dated October 26, 2007, p. 191

Nations government bodies, Terasen Gas is visible, listened to and able to ensure that its voice is heard and as such hurdles are overcome, projects gain support and existing customers benefit as costs are contained and new customers are added to the system. We believe we have been very successful in this area as can be evidenced by the successful Whistler Pipeline CPCN, Westbank First Nations Operating Agreement, UBCM Operating Agreements, and the TGVI LNG CPCN. As noted in Section III.A the municipal, provincial and federal energy landscape is changing and as such, Terasen Gas must increase its efforts in this area in order to be successful.

During the PBR Period specific activities in this area included:

- Operating Agreements – Terasen Gas signed and had approved 10 interior operating agreements with support from the UBCM, an operating agreement with Westbank First Nation, a Lease In Lease Out ("LILO") agreement with Creston and an approved operating agreement with Chetwynd. These long term agreements provide operating certainty in these communities and provide a platform for the efficient operation of the Terasen Gas infrastructure in those communities.
- Community Involvement – Terasen Gas believes it is important to be active in the community, give back to the customers in whose back yards we operate, and have an opportunity for person to person contact with our customers. For many customers, the only contact they have with Terasen Gas is when they receive a bill for gas service. By interacting with customers through the activities listed below, we are able to better understand and serve our customers. Some highlights of past activities include:
    - Terasen Gas Corporate Giving Program, Employees in the Community Program;
    - Community Projects (3 each year) - Holland Park, Surrey, Habitat for Humanity, Kelowna, Community Living Society, Victoria;
    - Involvement in: UBCM, Lower Mainland Local Government Association ("LMLGA"), Local Government Management Association ("LGMA") Newly elected officials, Southern Interior Local Government Association ("SILGA"), Association of Kootenay Boundary Local Governments ("AKBLG"), Northern Community Municipal Association ("NCMA"), Association of Vancouver Island and Coastal Communities ("AVICC"); and
    - Other - TGI kids strategy (presentations in schools around the Lower Mainland), Crosswalk kids program (schools within 200 metres of transmission ROW), Leadership BC Founding sponsor, BC Chamber of Commerce, Municipal Chamber of Commerce involvement, Business excellence awards, Luncheon attendance, Fraser Valley Cultural Diversity Awards, Anmore Day, Belcarra Day , World Rivers Day sponsor, Piper Spit Boardwalk project, Hat's Off

to Excellence Awards Gala, Langley Seniors Resource Centre, Langley Literary Association supporter, Maple Ridge Fair, Ridge Meadows Hospital Gala, Maple Ridge Arts Centre and Theatre, Fire & Life Safety Fair participation and support.

The introduction of the BC Energy Plan in 2007 marked a significant change in the energy policy landscape in BC. The Energy Plan's policy actions encouraged a new level of utility involvement in helping BC meet climate change objectives and emission reductions. With this new energy policy landscape, Terasen Gas' involvement with provincial ministries, both on the political and staff level, increased over the term of the PBR Period. Terasen Gas is now on over 12 separate ministry led committees relating to various energy policy actions. Terasen Gas has also met with Ministers, Deputy Ministers and staff in order to educate the government on Terasen Gas's business, and advocating for how the Company can play a role in meeting provincial energy objectives.

Going forward, Terasen Gas sees continuing increased need for community, First Nation involvement, Operating Agreements, Government relations and policy analysis.

(d) Summary of Customer Service over the PBR Period

Terasen Gas believes that it has been successful meeting the needs of our customers over the PBR Period recognizing though that there are opportunities for improvement in the outsourced meter-to-cash activities. Delivery rates have remained very stable and the majority of rates in real dollars have actually declined over the period. This, in large part, is due to prudent management and the Company's commitment to Operational Excellence. We believe the rate stability alone is a tremendous achievement, especially in light of the declining demand for natural gas over the PBR Period. It is even more notable given that we also met the majority of the customer service metrics as evidenced by the SQI scores. However, with this success comes increased expectations and, when combined with changing customer expectations, government policy changes, and changes in the competitive environment, Terasen Gas will have to invest more in its customer care service in order to improve the current levels of service to meet the evolving needs of customers.

(3) OPERATIONAL PERFORMANCE OVER THE PBR PERIOD

Terasen Gas has an established history as a Respected and Trusted Operator, providing safe, reliable and cost effective gas service to customers. Underpinning Terasen Gas' success to date is the Company's ability to consistently excel in operational performance by proactively responding to evolving regulatory and business needs. Following are discussions on:

a) Code Compliance;

b) Carbon Management;
c) Information Technology Strategy; and
d) Delivering on Major Projects.

These are all key Operational areas that Terasen Gas has been successful in responding to and delivering on over the course of the PBR Period, which have enhanced the Company's reputation as a Trusted and Respected Operator.

(a) Code Compliance

Legislation such as the *Utilities Commission Act*, *Oil and Gas Commission Act*, *Workers' Compensation Act, Environmental Management Act, Safety Standards Act,* fire codes and safety standards, Provincial and Federal *Emergency Acts*, CSA Codes, and other legislation, regulations and bylaws define our corporate level of reporting and compliance activities. These have a strong focus on public, employee, property and environmental safety as well as system reliability and have been introduced in Part III, Section A, the External Situational Context. A variety of external agencies oversee the company's response to these codes and regulations. Terasen Gas has a sound history of code compliance. The company's goal of providing safe, reliable, cost-effective and environmentally responsible service is strongly aligned to code requirements. These codes and regulations are outlined in the Table B-1-5 below.

Table B-1-5: Codes and Regulations that Impact Terasen Gas Business

Code/Regulation/Standard	Governing Body
B.C. Environmental Management Act	B.C. Ministry of Environment
BC Safety Standards Act and Gas Safety Regulations	B.C. Safety Authority
• Power Engineers and Boiler and Pressure Vessel Safety Act	B.C. Safety Authority: Pressure Vessels branch
B.C. Pipeline Act and Oil & Gas Commission Act (being replaced by Oil & Gas Activities act)	B.C. Oil & Gas Commission
CSA Z276: Liquid Natural Gas Production, Storage and Handling	Canadian Standards Association B.C. Oil & Gas Commission
CSA Z246: Security Management for Petroleum and Natural Gas Industry Systems (anticipated release October 2009)	Canadian Standards Association B.C. Oil & Gas Commission

Code/Regulation/Standard	Governing Body
CSA Z662 – Oil and Gas Pipeline Systems Including: • Clause 10.2 Safety & Loss Management System (annex A –framework) • Annex M: Gas distribution integrity management guidelines • Annex N: Guidelines for pipeline integrity management programs	Canadian Standards Association B.C. Oil & Gas Commission B.C. Safety Authority Workers' Compensation Board of BC
Electricity and Gas Inspection Act & Inspection regulations	Measurement Canada
WorkSafeBC Occupational Health & Safety Regulation • CSA Z1000 Safety Management System (framework)	Workers' Compensation Board of BC
Others including: • Provincial and Federal Emergency Acts; • Fire codes; • Building codes; • Emissions permits; • Municipal and regional bylaws; • Etc.	

For each of these, Terasen Gas has implemented management systems and/or operating practices to ensure compliance. The three examples that follow are given to demonstrate this:

(i) The Terasen Gas Integrity Management Plan;

(ii) The Terasen Gas Environmental Management Plan; and

(iii) Public Safety Awareness activities.

(i) Terasen Gas' Integrity Management Plan (IMP)

Terasen Gas is committed to providing safe, reliable, cost-effective and environmentally responsible service to its customers. A key method to ensuring this is the management of gas system asset integrity to ensure long life with low risk of failure leading to gas escape. In this regard Terasen Gas has an on-going commitment to maintain and enhance its integrity management practices.

The OCG's adoption of CSA Z662 Annex N as a mandatory requirement for BC pipeline operators has given Terasen Gas an opportunity to review and enhance its past integrity management practices and to formally document its integrity management plan to meet the code requirement.

Although only CSA Z662 - Annex N for pipeline systems is a regulatory requirement, Terasen Gas also included its distribution systems (Annex M) plus its LNG plant as it developed the Integrity Management Plan. This decision was appropriate because much of the workforce and the tools used in the day to day operation of the utility are not organized by operating pressure with skills and requirements being applied to system operating above or below 700 kPag.

Terasen Gas recognizes that hazards exist that influence and potentially impact the operation and integrity of its pipelines and facilities. The nature and significance of the hazards are influenced by asset-specific and external factors (i.e. geography). Using the CSA provided framework, Terasen Gas identified and documented the predominant hazards and built its integrity management programs around these. The programs documented within TGI's IMP exist to manage the risk associated with each of these hazards.

As Terasen Gas developed its formal Integrity Management System, primary focus was on improving process and accountabilities documentation. Programs to manage integrity have generally been in place for many years, although opportunities for continuous improvements can always be expected.

The key new activity required by Annex N, was the establishment of a formal quality management approach to integrity management. A regular review process has been established and metrics are being established for all integrity programs. Terasen Gas performed an internal audit of its IMP during December 2008. Ongoing 2009 activities are addressing identified improvement areas.

With the adoption of CSA Z662 Annex M and N formality and rigor around competency and training requirements for employees and other workers who impact asset integrity through their work is required. In order to comply with these requirements we are developing and implemented competency and training requirements for our workers, we are evaluating our workers and providing training where necessary.

To strengthen our records management processes, we are taking steps in all departments across the Company to comply with the various components of CSAZ662-07 Annex N Clauses 6.1 and 6.2. We have been working on a project to implement a formal and central records management system to manage compliance records on a go forward basis. As such, we are implementing a records management tool called FileNet and developed applicable records management processes to be used within this application. We are also implementing a sustainment model where all compliance records will be managed centrally.

To meet its commitment to providing safe, reliable, cost-effective and environmentally responsible service to its customers, Terasen Gas has and will continue to improve gas system asset integrity management activities. Terasen Gas believes that its IMP meets all code requirements of Annex N and is ready for OCG auditing expected towards the end of 2009. In addition the Company believes that its IMP forms a solid base on which to build the requirements of CSA Z662 Clause 10.2 Safety and Loss Management Systems, also referred to as Annex A.

(ii) Terasen Gas' Environmental Management Plan

Terasen Gas is committed to the philosophy that sound safety and environmental practices make good business sense. The company's success in the area of environmental management is based in part on developing and maintaining an effective Environmental Management System ("EMS") that is compliant to ISO 14001 Environmental Management Systems standard.

The Environmental Management System provides guidance to the Company, its employees, and its contractors on how to comply with all applicable environmental laws, Company policies and industry codes of practice. Audits, inspections and incident investigations drive monitoring and system improvements through the Environmental Management System. Corrective actions identified in audits, inspections and incident investigations are used to improve the system and minimize the risks.

(iii) Terasen Gas' Public Safety Awareness Activities

Terasen Gas has a responsibility to educate the public about the risks associated with its natural gas and propane products. One of the Company's main objectives regarding public safety awareness is to support safe, secure and healthy communities by increasing public awareness of gas safety risks and the steps that can be taken to minimize the potential for accidents.

A variety of methods including media ads, bill inserts and the Terasen Gas web-site have been used as channels for this program during the PBR Period. For example: Terasen Gas has recently become a financial sponsor of the Cooperative Safety Program, which provides education to communities across the southern interior of British Columbia. The multi-media campaign focuses on increasing utility safety awareness to both the general public and industry professional audiences. The Company is of the view that efforts in this area are extremely important and the Company intends to continue and enhance its efforts in the future.

In summary, Terasen Gas has implemented management systems and/or operating practices to ensure compliance. Terasen Gas is also proactive in looking for improved ways to provide safe, reliable, cost-effective and environmentally responsible service. Terasen Gas looks to industry best practices to help shape its own operating principles, adopting sound practices well before they become mandatory. Many of these best practices come from industry associations and industry code groups. Terasen Gas is a member of several industry associations, such as the CGA, the WEI, NWGA, and Canadian Energy Pipeline Association ("CEPA"). Terasen Gas is also active in specific working groups of these associations, with an example being the CGA asset management task force. Terasen Gas intends to continue focusing its efforts in this area in its pursuit of continuous improvement and Operational Excellence.

The Company will next discuss the second of the four areas of operational performance, being its successful carbon management activities.

(b) Carbon Management of Terasen Gas Operating and Customers Emissions

Since 1995, Terasen Gas has reduced GHG emissions from its operations through voluntary, efficiency-based initiatives. Today, the Company continues to be an active leader in minimizing environmental impacts and GHG emissions ("emissions") of utility operations, while providing value to customers through energy efficiency and conservation programs. The Company is committed to advancing government policy objectives and providing integrated energy solutions to customers and communities that help them reduce their own emissions. Emission reduction measures will help the Company and its customers reduce compliance costs associated with future GHG regulations. Also, using natural gas more efficiently will reduce utility and customer costs associated with the BC carbon tax. This proactive approach ultimately helps reduce costs associated with emissions for the customer by avoiding future regulation costs or by not having to pay the carbon tax associated with fossil fuel consumption.

The following section provides an overview of BC's total GHG emissions. Following that is a discussion of emissions associated with the Company's operations and its customers' consumption of natural gas. We also review some of Terasen Gas' historical activities and programs to manage these emission levels.

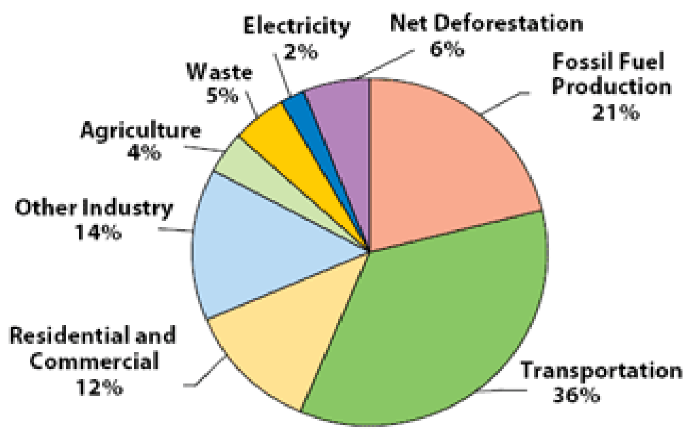
Scientific evidence suggests that it is very likely that increased emissions from human activities are affecting the atmosphere, accelerating global warming. Understanding the sources of these emissions allows us to identify the most effective emission reduction measures. In this section we will look at BC's overall emissions and summarize how Terasen Gas' operating and customer emissions contribute to these emissions.

(i) BC Emissions Overview

In 2006, BC emitted a total of 69 million tonnes of GHGs, measured in carbon dioxide equivalent, representing 9.6 per cent of Canada's total emissions.[104]

As shown in Figure B-1-9, transportation sector accounts for the largest share of emissions in BC, representing 36 per cent of all emissions, followed by the fossil fuel production industry at 21 per cent.[105]

Figure B-1-9: BC Emissions Output Unique



Source: See Appendix C-10 for a copy of Climate Action Plan

Emissions have been increasing significantly over the last decade within BC; total emissions grew about 30 per cent in BC between 1990 and 2004, in line with increasing population. An increase in population creates increased demand for energy production and consumption, which is the largest source of emissions.[106]

What makes BC unique relative to other jurisdictions regarding the output of GHG is the sources of these emissions. As Figure B-1-2 shows, BC has only 2 per cent of its GHG emissions coming from the electricity sector. This is a much lower proportion compared to many other jurisdictions where a much higher proportion of the provincial or state emissions come from the electricity sector.

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[104] As per Climate Action Plan, p. 56, "In British Columbia's case, the "business as usual" scenario would result in emissions of approximately 78 million tonnes by 2020 (over 9 million tonnes more per year than today)". (78 million tonnes – 9 million tonnes = 69 million tonnes)

[105] See Appendix C-10 for a copy of Climate Action Plan

[106] See Appendix C-48 for a copy of Climate Change in Canada – Greenhouse Gas Emissions

For the year 2006, 12 per cent of BC's total emissions came from the consumption of natural gas in the residential and commercial sectors.[107] Additionally, 14 per cent of BC's total emissions came from the "other industry" sector.[108] Emissions from natural gas consumption are one component of the total emissions from this sector. Finally, 2 per cent of BC's natural gas emissions occur in the electricity sector.[109] It is estimated that Terasen Gas Inc. and Terasen Gas Vancouver Island Inc. operating and customer emissions made up approximately 17 per cent of BC's total emissions in 2006.

(ii) Review of Terasen Gas GHG Operating and Customer Emissions

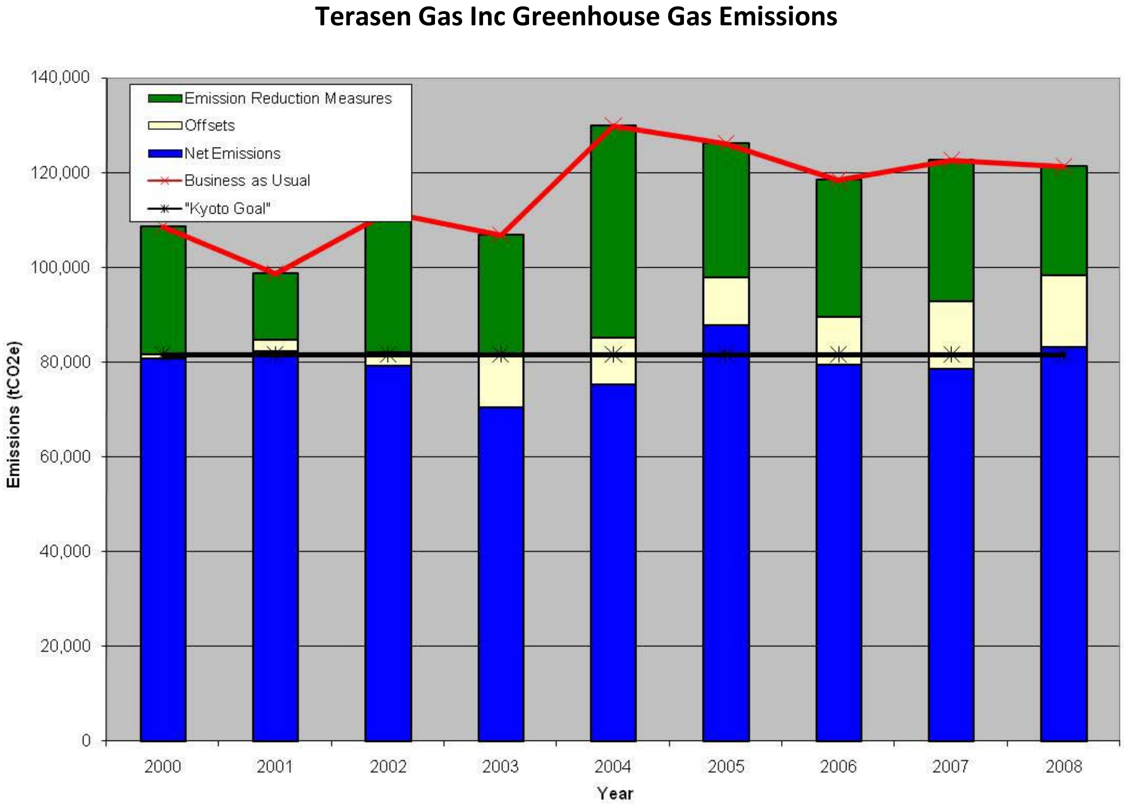
Terasen Gas has been reducing operating emissions since 1995 through voluntary, efficiency-based programs. Also, since 1997, the Company has undertaken projects for customers to reduce emissions from natural gas consumption. Together these initiatives and projects have reduced the environmental impact of transmitting, distributing, storing and consuming natural gas within BC.

By the year 2000, Terasen Gas Inc. had reduced emissions from its operations, buildings, vehicles, and electricity consumption to 6 per cent below 1990 levels. The year 2000 has since been used as the baseline year for internal benchmarking for emission reductions. The Company's reduction measures have avoided an estimated 231,449 tonnes of emissions since 2000.

Figure B-1-10 shows Terasen Gas Inc. emissions and emission reduction measures from operations for the period between 2000 and 2008. The Company estimates that on average the Terasen Gas Inc. produces slightly over 100,000 tonnes of emissions per year from its operations. The Company holds this accomplishment in high regard given that the customer base increased from 757,369 customers in 2000 to 834,211 customers in 2008.

[107] See Appendix C-10 for a copy of Climate Action Plan
[108] Ibid
[109] Ibid

Figure B-1-10: Managing Operating Emissions to Year 2000 Levels



Some of the emission reduction measures the Company has taken include:

- Expanding the use of mobile compressors that transfer gas from one part of the system to another during construction or maintenance procedures;
- Removing older style bath heaters as they reach the end of their service life and replacing them with high efficiency boilers;
- Replacing older station controllers that are designed to vent gas to the atmosphere;
- Eliminating all low pressure main and services;
- Using hi-flow samplers to measure leak volumes at major stations on the system;
- Changing LNG Plant operating practices to reduce vented emissions; and
- Investing in offset projects that reduce natural gas use in other industries by utilizing landfill gas.

Since 2000, these reduction measures have helped reduce emissions by over 21 per cent or 231,449 tonnes. These results show that Terasen Gas is committed to reducing emissions from its own operation.

The Company has long been involved in a number of different initiatives and projects to reduce emissions arising from customers' use of natural gas. The main initiative undertaken by the Company is DSM or EEC, which is focused on helping customers use energy more efficiently.

Since the late 1990s, the Company has experienced a high degree of success with its EEC programs. EEC activities undertaken by the Company have the goal of affecting customers' use of natural gas through energy conservation. The energy efficiency activities result in reduced consumption of natural gas, and hence lower emissions.

Table B-1-6 outlines the energy savings and GHG reduction as a result of number of different energy efficiency programs implemented since 2005.

Table B-1-6: Helping Customers Reduce Their Carbon Footprint

TGI DSM Program Energy Savings and GHG Reduction

	2005	2006	2007	2008
Annual savings (GJ)	1,349,762	735,207	1,203,596	612,651
GHG Impact (tonnes, NPV)	68,419	37,268	61,010	31,055

Each year's energy savings and therefore GHG reductions depends on a number of factors, including available funding, number of programs, and number of participants in those programs. This explains why there are variable results every year. For instance, in 2008, TGI experienced a lower annual savings and GHG impact when compared to 2007, which can be attributed to a reduced participation rate (4,498 as compared to 4,795 in 2007).

In summary, Terasen Gas' past history in operating emission reductions is a story that the Company is very proud of. The Company has a long standing history of being proactive in this area and there is a need to continue to build on this good work. Terasen Gas has also been providing customers directly with solutions to manage their energy use, and therefore their emissions, through such offerings as EEC programs. However, given changing customer expectations and government policy objectives around emission reductions, Terasen Gas needs to provide customers and communities a broader set of solutions to reduce their emissions.

Please see Part III, Section C, Tab 3 of the Application for more details on customer solutions that will help them reduce their emissions footprint. The following section, which is the third of four sections where we discuss the key areas of operational performance, will review the Company's Information Technology strategy for the PBR Period.

(c) Information Technology Strategy

Utilization of information technology effectively has been an important contributor to the success of Terasen Gas' business in its pursuit of Operational Excellence. Terasen Gas is reliant on its information technology systems to provide efficient and cost effective service to its customers. The key strategies for information technology during the PBR Period have been focused on adopting industry best practices and embracing standardization where applicable.

All business applications are dependent on the infrastructure that they run on and the tools that people use to access them. The total cost to the company when people cannot use the systems can be significant. It is essential that the technical infrastructure supporting the business be robust, stable and reliable. To that end, Terasen Gas has instituted an industry best practice of scheduled refreshes of key equipment. These refresh programs ensure that equipment such as desktops, laptops, servers, printers and network equipment are replaced in a scheduled manner to ensure reliability and compatibility with the newer software requirements and repair costs are managed.

The same way that infrastructure must be refreshed periodically, so too must business application software. Vendors typically support a version of a software package for only so much time and then it must be upgraded or replaced. The same is true for custom built applications with the reasons essentially the same. It is expensive and sometimes impractical to maintain the skills around a programming language or a version of software that is at end of industry life. The most notable of these efforts was the replacement of various mobile solutions utilized by Terasen Gas to manage the different field work forces (construction, customer service and maintenance). Product changes, vendor acquisitions and old technology needed to be addressed. This project was initiated in late 2006 and successfully implemented in Q4, 2008.

Standardization has been another strategic focus for Terasen Gas in the past during the integration of TGVI with TGI. Upon acquisition of TGVI, Terasen Gas implemented a common mind and management approach which involved standardizing on best practices from both companies and enabling standard, consistent business practices to deliver services to customers in the most cost effective manner. Simplifying the technical architecture by reducing the number of applications supporting the same business processes reduced the total cost and enabled consistency throughout the organizations.

In summary, effective utilization of information technology has been and will continue to be a priority for Terasen Gas to support its business needs. In the next section, which is the last of the four sections where we discuss the key areas of operational performance, we will review the implementation of major projects the Company has undertaken during the PBR Period.

(i) Implementation of MAJOR projects

Over the term of the PBR Period, Terasen Gas has successfully implemented a number of major capital projects to meet the needs of its customers and contribute to the Company's commitment to provide a safe, reliable and efficient gas service. Following are descriptions of some of the significant capital projects implemented.

Vancouver Low-Pressure ("LP") Gas Distribution System to Distribution Pressure ("DP") Replacement and Upgrading - $17.6 million

Safety and system reliability are key considerations in maintaining the integrity of Terasen Gas Distribution System. System age often has a prominent influence on system reliability and safety.

The Vancouver LP Gas Distribution System was the last remaining section of the original coal gas networks that served the Lower Mainland, dating back to as early as 1886. In 1956, the system was converted to distributing natural gas. Since that time sections of the LP system were replaced but large segments still remained; approximately 95 km of mains, 7,100 services, and 24 pressure regulating stations located in 5 well established densely-populated neighbourhoods in the Western portion of the City.

As there was significant risk to the integrity of the system from ground disturbance, Terasen Gas believed the replacement of the Vancouver LP Gas Distribution System was in the best interests of customers, employees and the public. Due to the condition of the pipe in combination with past construction practices, even minor ground disturbance posed a risk to the integrity of the LP pipe. Terasen Gas believed that if a major seismic event did occur, there was significant risk that a large portion of the LP system would have failed.

Approval to proceed was granted by the British Columbia Utilities Commission dated June 26, 2006 in response to Terasen Gas' CPCN application.

This project is now complete with the following benefits realized:

- Project completed ahead of schedule and significantly under budget. The projected final cost is estimated at $18.4 million vs. a project budget of $23.7 million;
- Improved safety, reliability and integrity of the gas distribution system;
- Reduced exposure to significant interruption of service for Vancouver LP Gas Distribution System customers due to a seismic event;
- Reduced intrusion into customer's premises as LP meters previously located indoors were relocated outside;
- Increased system capacity to allow the addition of new customer load;
- Reduced ongoing operating and maintenance activities as a result of the removal of several pressure control stations associated with the Vancouver LP Gas Distribution System; and
- Reduced ongoing maintenance activities related to water removal as well as leak and break repair in the Vancouver LP Gas Distribution System.

Terasen Gas will continue to maintain a strong focus on system integrity through all areas of the Distribution System to ensure that customers continue to enjoy safe, reliable and cost effective delivery of natural gas.

Distribution Mobile Solution - $6.0 million

Terasen Gas, like other utility companies rely on effective scheduling and dispatching systems to optimize deployment of their workforce and manage activities. Terasen Gas field crews engage in customer service, construction and maintenance activities totaling approximately 200,000 work orders annually. We are of the view that for a utility of Terasen Gas' size and scope it is more efficient and cost effective to manage its mobile workforce without relying on manual processes.

Terasen Gas Inc. submitted an application for a CPCN dated May 7, 2007 requesting an approval from the British Columbia Utilities Commission to implement a technology solution – Distribution Mobile Solution ("DMS"), for managing all field work and resources. An approval was granted in Order No. C-5-07 dated July 5, 2007 with actual spending to date for the project under the BCUC allowed cost cap.

A primary consideration in the project justification was a significant risk that the technology in place at the time of the CPCN application would fail due to aging components that were no longer being manufactured and some software components that were subject to significantly reduced vendor support. The potential consequences of system failure would be a sustained technology outage that would have significant implications on Terasen Gas' ability to dispatch, and thus efficiently perform, day-to-day customer service work.

The project went "live" October 2008 with the following results being realized to date:

- Customer Service work successfully migrated from Mobile UP to SAP R/3 enabling all work orders to be managed, tracked and reported in the same way.
- Expanded the use of ClickSchedule to include Customer Service and Preventative Maintenance work so that all Distribution field resources are now dispatched on a common system.
- Field data capture, live updating of job statuses and mobile timesheet applications implemented for all Distribution field resources.
- Once the software has been in service for a complete year, the following benefits will be fully realized:
  - Improved optimization of field resources;
  - Elimination of complex, duplicated, and error prone resource management processes;
  - Elimination of manual data validation and entry;
  - Elimination of time and costing data reconciliation;
  - Improved communication between Dispatch and field employees;
  - Automation of preventative maintenance processes; and
  - Access to historical maintenance data in the field.

Terasen Gas' field employees play a critical role in providing safe and reliable delivery of natural gas to our customers. With the Company now on a stable and single technology platform for managing its field resources, customers will benefit now and in the years to come.

Nucleus Deal Capture Project for Gas Supply - $1.8 million

Gas Supply provides the gas and propane supply management function, which encompasses most elements of the merchant role, as well as providing transportation services for industrial and commercial customers. This includes providing intra-day balancing supply (required primarily due to weather changes) for core customers, facilitating all gas scheduling and nominations on the Terasen Gas and third party pipeline transmission systems, mitigation activity based on buying and selling around excess resources and the management of relationships with financial and physical supply counterparties, storage operators and pipeline companies to the benefit of Terasen Gas' customers. Also included is the management of the movement of gas supply provided by marketers to customers under the commodity unbundling program, which began in 2004.

In order to effectively manage costs and revenues related to these functions and accommodate the implementation of the commodity unbundling program, Gas Supply implemented an integrated information system in 2004. The Nucleus Deal Capture project replaced the previous reliance on multiple spreadsheets and MS-Access databases and provided an integrated system capturing deal entry through to invoicing, reporting and cost management. Furthermore, the system prior to Nucleus was not capable of handling the separation of costs from the Gas Cost Reconciliation Account ("GCRA") into to Commodity Cost Reconciliation Account ("CCRA") and Midstream Cost Reconciliation Account ("MCRA") necessary under the commodity unbundling program. The benefits of the Nucleus system over the years include:

- Single source of information for commodity, storage and transportation deals;
- Improved management of contracts;
- Real-time credit and contract information to support enhanced risk management;
- Enhance ability to assess and monitor compliance and risk;
- Ability to make daily decisions from an integrated viewpoint enabling an optimal use of assets;
- Ability to manage costs for other entities such as Terasen Gas Vancouver Island and Pacific Northern Gas or other Energy Management Services clients;
- Ability to identify and immediately act on potential business and revenue opportunities;
- Support Southern Crossing Pipeline and future related business;
- Support Commodity Unbundling, including management marketers' volumes and related invoicing; and
- Provide timely and accurate information to other systems and departments within the Terasen Gas organization.

This Nucleus product will no longer be supported by the vendor after 2009 and so Gas Supply plans to upgrade to the Entegrate system offered by the same vendor by the end of 2009. As such, this system will continue to serve to centralize data, providing information relating to costs, revenues, and risk and credit management for Gas Supply and will continue to meet the growing needs of the group in the future.

Transmission AM/FM Project - $2.0 million

During the course of the PBR Period, Terasen Gas implemented an Automated Mapping / Facilities Management (AM/FM) Geographic Information System (GIS) system for its transmission pressure pipeline assets. This action supported Terasen Gas' vision of securing and optimizing the base business, becoming more focused on transmission pipeline asset management and serving the existing Terasen Gas customers more effectively. This implementation replaced the paper based as-built and computer-assisted drafting (cad) based record system with an enhanced Automated Mapping system. In turn, Terasen Gas has realized the benefits listed below.

Relative to the former paper based and CAD based systems, the Transmission AMFM GIS system has enabled the Transmission group to;

- More effectively manage risk of third party damage associated with its facilities by having more accurate and up to date information available;
- Have a consistent BC One Call response process in place across the all service territories;
- Have data available on a centralized system with defined accuracy, security and redundancy;
- Make available a complete set of accurate data to other users within Terasen Gas, thereby reducing or eliminating duplication and inaccuracies and support communication of accurate data to external parties;
- Provide current and accurate digital landbase and asset data to third parties and receive the same from them. Many new initiatives require information in digital format;
- Replace the existing BC Hydro Right of Way Management Line List application;
- Update and maintain the Pipe Line List and provide accurate pipeline data for Transmission Planning, and Oil and Gas Commission requests in the required XY location based; and
- Capture right of way property information for Transmission, Intermediate Pressure and Distribution Pipelines.

At completion which was finished on budget, the Transmission AM/FM Project provided the Transmission group with an integrated AMFM GIS solution for Transmission records and business processes. It supported business processes related to Asset Management, BCOneCall, Pipeline Operations, Right of Way Property Management, and Transmission Planning.

Customer Attraction Front End Project - $1.4 million

In 2006, Terasen Gas implemented the CAFÉ Project. CAFÉ was initiated by Marketing to integrate the TGVI sales processes into TGI, address sales and marketing issues related to the Order Fulfillment process and to support the Company's long-term customer growth objective through improvement of existing business processes and the addition of new processes, where appropriate. CAFÉ included a review of best practices in the areas of customer contact, account management and lead development and established a company-wide business operating model upstream of Order Fulfillment process. The CAFÉ project implemented the following marketing and sales enhancements:

- Implementation of business processes that support efficient development and execution of Marketing and Sales plans and programs/activities including content management:
- A new technology application to process construction orders and support effective customer growth cycle management which included standard models for:
  - Marketing content management,
  - Customer Growth Cycle management including:
  - Issue tracking,
  - Billable hazard order processing,
  - Service product pricing,
  - Relevant and timely macro and micro reporting of customer activity and lead status.

CAFÉ has resulted in an improvement to the Order Fulfillment process and Marketing and Sales process by creating a process and technology interface between the upstream lead management model and the downstream "factory production" model.

Service Delivery Enhancement Project - $5.0 million

In 2005, Terasen Gas implemented the Service Delivery Enhancement Project (“SDE”). SDE was initiated by Distribution to improve the efficiency and performance of the Order Fulfillment process from order initiation to closing. SDE focused on business processes, organizational structures and technology enhancements to support work order scheduling and dispatching. SDE specifically targeted improvements in areas such as: scheduling and field crew workforce planning, accountabilities among field managers and crew leaders, improving customer interaction through the Install Centre and improved reporting to support production management. A key feature of SDE was the design and implementation of a new scheduling platform (ClickSchedule) and a mobile communications platform (SAP Mobile Asset Management). SDE delivered significant improvements to the Order Fulfillment process enabling Terasen Gas to effectively manage customer growth-related activities.

Commodity Unbundling Program - $17.0 million

Policy Action #19 of the 2002 BC Energy Policy states that "*Natural gas marketers will be allowed to sell directly to small volume customers*". Terasen Gas responded to this government policy objective by first providing commodity choice to small and large commercial customers in November 2004. Independent licensed gas marketers were able to provide long term fixed rate options to gas customers. In November 2007, after the successful launch of the Commercial Unbundling phase, the program was expanded to include residential customers with the launch of the Customer Choice program, completing the second phase of the implementation of the Commodity Unbundling program for small volume customers

The implementation of both phases of the Commodity Unbundling program has been a qualified success as the solution was implemented within the approved level of funding; was delivered on time; and provided the required functionality. In addition, the program rules and system design have been functioning as designed and are working well. A testament to this is that during 2008, two gas marketer failures were successfully managed with the affected customers transferred to other gas marketers with no supply interruption. Response to the program by residential customers has been good with the level of customer complaints and disputes manageable, although higher than anticipated. Customer participation in the program at the end of March 2009 stood at approximately 121,000 residential and 20,000 commercial customers, representing 17 per cent of all customers eligible to participate.

Terasen Gas continues to work cooperatively with gas marketers, the Commission and interested stakeholders to enhance the program. Terasen Gas remains committed to providing effective customer choice that meets the needs of the marketplace and provides value to customers.

(d) Summary of Operational Performance over the PBR Period

Code Compliance, Carbon Management, sound development and execution of an Information Technology strategy, and Delivering on Major Projects are fundamental to Terasen Gas' reputation as a Respected and Trusted Operator, providing safe, reliable and cost effective gas service to customers. Over the past number of years, Terasen Gas has been successful in delivering and responding to these evolving regulatory and business needs.

Terasen Gas has a solid history of code compliance and has implemented management systems and/or operating practices to ensure compliance including an Integrity Management Plan and an Environmental Management Plan. As part of its efforts, Terasen Gas continues to be proactive in looking for improved ways to provide safe, reliable, cost-effective and environmentally responsible service. For operating emissions management, Terasen Gas has a long standing history of being proactive in this area.
Terasen Gas has implemented an Information Technology strategy that is focused on adopting industry best practices. Key aspects of this strategy are scheduled refreshes of key equipment, infrastructure and application software, and standardization of processes and infrastructure where applicable. The strategy has contributed to the operational success of the Company through the PBR Period.

Terasen Gas has an established record for successfully implementing major capital projects, helping to provide safe, reliable and efficient gas service to customers. Over the term of the PBR Period, Terasen Gas has maintained its track record by implementing a number of major capital projects successfully including the Low Pressure System Renewal, Distribution Mobile Solution, Nucleus Deal Capture, Transmission AM/FM, Customer Attraction Front End, Service Delivery Enhancement and Commodity Unbundling.

Terasen Gas efforts in the above areas continues to reinforces our role as a respected and trusted operator, providing safe, reliable and cost effective gas service to its customers. In the next section, the Company will review its efforts regarding the management of its workforce.

(4) EMPLOYEE IMPACTS OVER THE PBR PERIOD

Having a balanced scorecard and striving for Operational Excellence requires maintaining an employee focus. During the term of the PBR Period, Terasen Gas has concentrated on retaining, attracting and motivating employees. This ultimately resulted in TGI being better positioned to meet the needs of customers. The key areas where Terasen Gas has been able to demonstrate its commitment to its employees are in;

a) Employee safety;
b) Managing changing employee demographics; and
c) Managing talent.

(a) Employee Safety

At Terasen Gas, employee health and safety is a key component of Operational Excellence, and one that we incorporate into every element of our business. In order to promote and maintain a safe and healthy workplace for our employees, we operate according to following values:

- Safety will be given first priority;
- All injuries are preventable;
- Excellence in safety will contribute to excellence in business objectives;
- Prevention of injuries is a line responsibility from the president to the individual employee;
- A high level of employee involvement in safety activities is fundamental to safety excellence;
- Safety must be integrated into every job function at Terasen Gas; and
- Our goal is zero lost time injuries, zero medical aids and zero recordable vehicle accidents.

In recognition and support of these values, Terasen Gas has developed a Safety Management Program that is designed to identify, assess and reduce risk to employees. This Program is comprised of a variety of elements, including:

6. Determination of performance objectives and challenges;
7. Hazard identification and analysis;
8. Standards and procedures;
9. Regulatory ,monitoring and compliance;
10. Training;
11. Disability management;
12. Inspection and monitoring;
13. Occupational hygiene;
14. Injury reporting and investigation;
15. First aid;
16. Records and statistics;

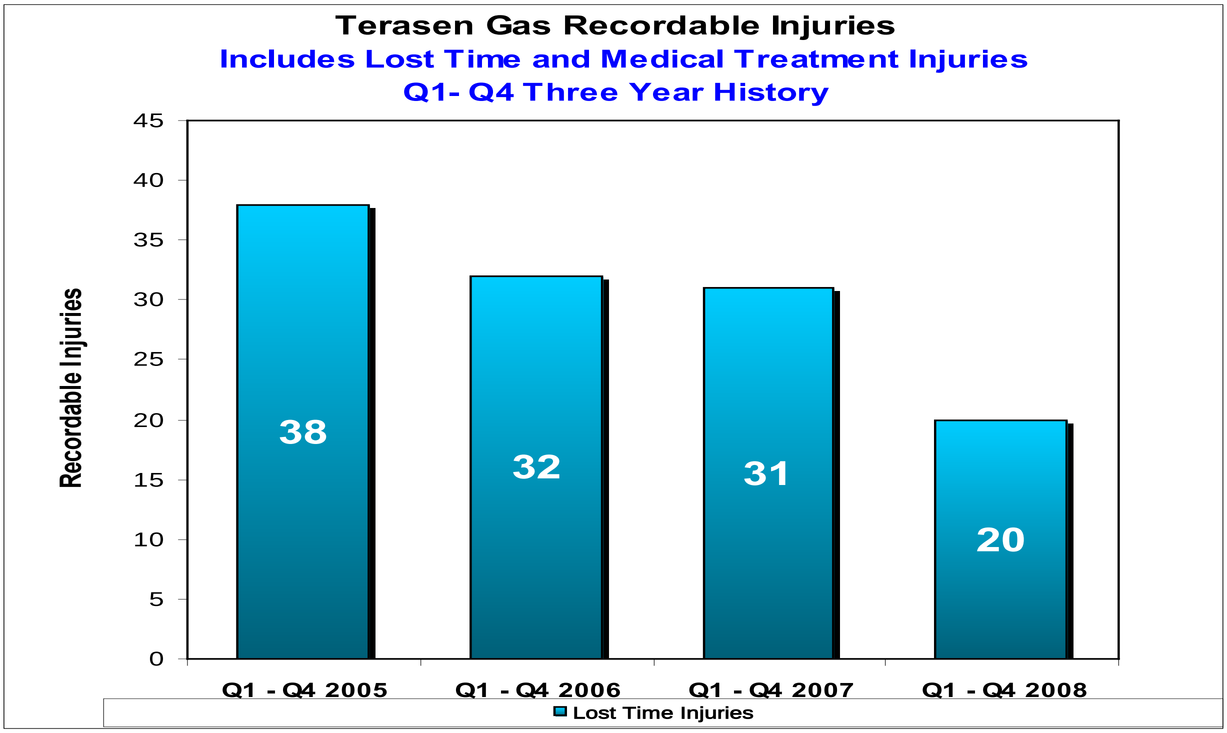
17. Communication; and
18. Audit.

Our Safety Management Program contributes to the health and safety of our workforce and the public, both of which are critical elements in the road to achieving Operational Excellence. Several of the Company's Service Quality Indicators are directly linked to public safety. In addition, two of our corporate scorecard measures directly measure workplace health and safety - Recordable Injuries and Recordable Vehicle Accidents. These measures are explored further below.

(i) Recordable Injuries

Terasen Gas classifies Recordable Injuries as both Lost Time Injuries and Medical Treatment Injuries. With a goal of zero lost time injuries and zero medical treatments, Terasen Gas is always striving to meet its objectives and improve its experience in these areas. We measure Recordable Injury performance against our previous three year average. Since 2005, the number of Recordable Injuries has been trending downward. For 2008, The Company's performance related to Recordable Injuries came in well ahead of challenge level. Terasen Gas experienced 20 Recordable Injuries during 2008, compared with an average of 33 for the previous three years. This achievement exceeded the challenge on the Corporate Scorecard of having no more than 28 Recordable Injuries.

Figure B-1-11: Recordable Injuries have been Declining

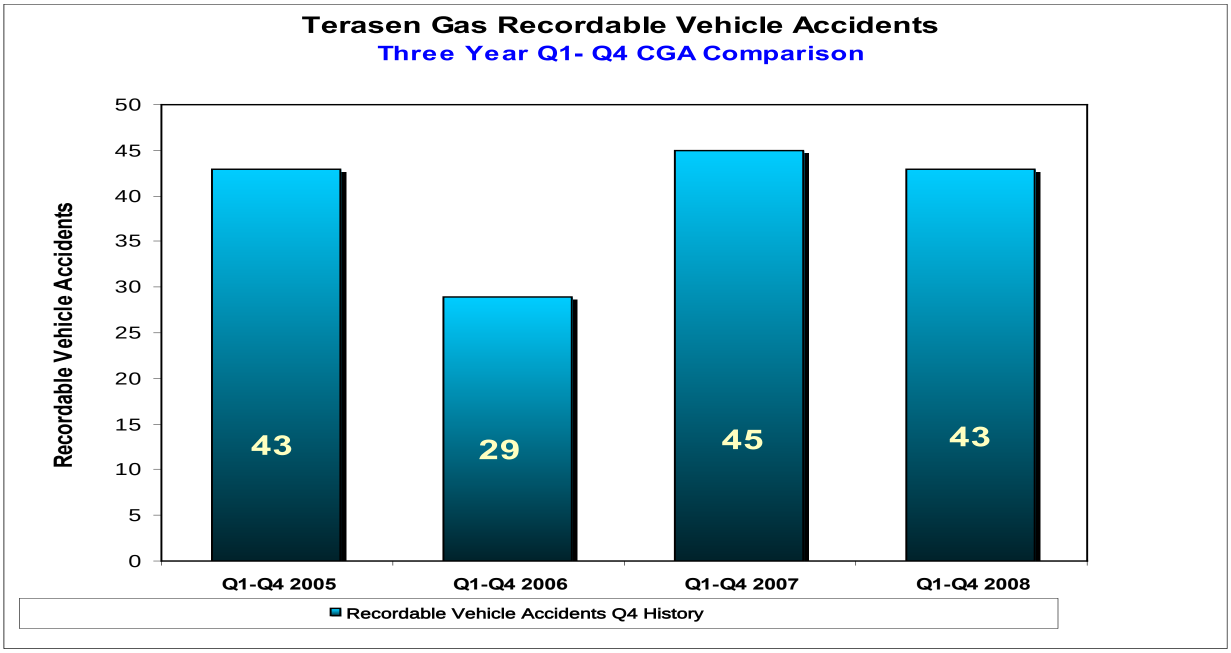


Our focus on employee health and safety has resulted in the Company reducing the number of Recordable Injuries experienced by employees and thereby reducing our three-year rolling average. While we are proud of our achievements in this area, safety is not an area that can be taken for granted, we are of the view that continued vigilance in this area is necessary now and in the future.

(ii) Recordable Vehicle Accidents

As mentioned above, another of Terasen Gas' safety values is to achieve a goal of zero Recordable Vehicle Accidents. This has been a challenge for us over the years, and one that remains a focus of the Company. A Recordable Vehicle Accident includes all avoidable and non-avoidable vehicle accidents, irrespective of damage amount. For 2008, Terasen Gas' performance related to Recordable Vehicle Accident came in just short of its challenge level. Terasen experienced 43 Recordable Vehicle Accidents during 2008, compared with an average of 39 for the previous three years. As with Recordable Injury performance, Terasen measures Recordable Vehicle Accident performance against its previous three year average.

Figure B-1-12: Number of Recordable Vehicle Accidents has not been Improving



In recent years, we have not been successful in reducing the number of Recordable Vehicle Accidents experienced by employees according to our three-year rolling average. We have work to do in this area, and believe that continuing to build our safety culture through communication, education and engagement will bring about desired results in the future. The Company is committed to continued vigilance in this area.

(iii) Summary of Employee Safety

Each year, Terasen Gas sets increasingly challenging safety goals to influence a reduction in employee injuries and vehicle accidents. Terasen Gas continues to meet and exceed these challenges and remain comparable to peer CGA companies. Terasen Gas places a high priority on the safety of its employees and continually strives to improve and upgrade the safety management system in order to meet these safety challenges, and intends to continue to place a high priority on safety in the future.

(b) Employee Demographics

As mentioned earlier in this RRA (see Part III, Section A, Tab 1), shifting workforce demographics are a well-known global reality and a major source of concern for governments and businesses alike. Terasen Gas has been aware of the general demographic challenges for some time and has undertaken a variety of steps over the years to manage changes in its workforce and mitigate these risks, and will continue to do so. Meeting these challenges is key to being able to properly serve our customers in the future.

Table B-1-7 below reflects the Company's success in managing overall personnel levels during the PBR Period. The total number of FTE employees was relatively flat following the USP (2004-2007) and in 2008 was still below 2003 levels. The upward trend from 2007-2008 recognizes actions taken to manage the demographic risks and the nature of the changing business environment. With almost 50 per cent of current employees becoming eligible to retire (with either a reduced or unreduced pension) within the next 5 years, the Company's current business strategy and on-going need to manage this retirement risk will continue to drive the need for additional human and financial resources. [110]

Table B-1-7: No Increase in FTE Employees Between 2003-2008

Terasen Gas
FTE Reconciliation

	2003	2004	2005	2006	2007	2008
Distribution	510	499	488	468	481	503
Finance, Reg Affairs	58	59	61	59	58	63
President	43	4	2	2	2	2
Business & IT Services	311	284	298	293	300	311
HR & Operations Governance	92	93	90	85	84	87
Marketing	86	65	64	75	80	80
Gas Supply & Transmission	89	85	89	80	81	80
Total TGI	**1,189**	**1,089**	**1,092**	**1,062**	**1,087**	**1,127**

(i) Strategies to Manage Retirement and Recruitment

Given that we have been aware of the demographic challenges facing the Company for some time, a number of actions have been undertaken to mitigate retirement risk, including:

19. Working with business departments to identify critical roles, develop replacement plans for those roles where possible, and also to develop workforce plans to rely on in the event those roles become vacant;
20. Having business departments plan for knowledge transfer by documenting procedures, creating training manuals, updating standards, and developing knowledge bases using the various technologies available to them; and
21. Working with business departments to consider how work is being done and looking at how it could be done differently with available personnel and skill sets.

[110] See Appendix F-2 for a copy of Headcount History and Demographic Data

The Company has also become much more pro-active in its recruiting initiatives. Much work has been done to develop an employer brand that complements our corporate brand and is reflected in the new look and feel of our "Comfort Expert" advertising campaigns. Our employer brand promotes the opportunity to build a long-term career with a stable employer who recognizes and rewards individual effort at work and in the community. This message is reinforced on our Careers web-site by testimonials that feature various employees and career paths.

Other recruiting strategies include utilizing new technologies (i.e. on-line job boards and networking sites), increasing our presence in the job marketplace through participation at various career fairs (UBC, SFU, BCIT, UFV), establishing partnerships with professional associations (Certified General Accountants of BC, ASTTBC, Aboriginal Human Resource Development Associations) and employment services groups representing recent immigrants, people with disabilities and returning armed forces personnel. Recent examples of these activities worth noting include:

- Terasen and FortisBC partnered with ASTTBC for representation at the WorkBC Job Fair sponsored by the Government of British Columbia and held at a number of locations in Southern Ontario. ASTTBC promoted job opportunities available at both Terasen and FortisBC.
- Terasen partnered with a number of other large employers, the City of Prince George, and the Prince George Chamber of Commerce to hold a job fair targeting skilled trades workers displaced by the downturn in the local forest industry.
- Terasen Gas contributed to the first ever Utility Construction Boot Camp held at the Chemainus First Nation – a partnership with other utility industry employers (Corix Utilities, Spectra Energy, BC Hydro and BC Transmission Corp) and the Aboriginal Human Resource Development Association. In conjunction with these partners, Terasen sponsored a 10 day boot camp designed to prepare First Nations candidates for potential employment in the utility construction industry. Additional Boot Camps are currently being planned with Sea Bird Island and Sto:Lo First Nations.
- Representatives from Terasen Gas Aboriginal Relations and Recruiting Services met with Snuneymuxw First Nation in Nanaimo to discuss employment opportunities and pre-requisites for certain types of positions, available funding for courses, educational opportunities, and types of careers that are available after one or two years of training in the technician and technologist fields. Terasen Gas Recruiting Services also participated in a two-day Career Fair sponsored by the Nuu-chah-nulth Tribal Council in Port Alberni and another in Kamloops.
- Additional efforts are being made to capitalize on the emerging retiree pool as a source for talented part-time employees to assist with training and knowledge transfer. The recent elimination of mandatory retirement and accompanying legislative changes may also provide

eligible retirees with more options which could potentially help mitigate skilled labour shortages.

Another example of the Company's efforts to manage headcount and costs during the PBR Period was the adoption of a Vacancy Management Strategy by Distribution, Transmission and Operations Support departments in anticipation of the negotiation of a new Collective Bargaining Agreement with the IBEW. In 2006, during the IBEW contract negotiation period, these departments implemented a partial IBEW hiring freeze policy which resulted in additional vacancies due to significant number of outgoing retirees not being replaced. Where possible, the work activity was shifted to install contractors. However, Terasen continued to replace operating, maintenance and emergency response positions. In 2007, with a new contract in place, Terasen established a Distribution apprenticeship program to meet the demographic challenge. Two waves of apprentices were recruited in 2007 and 2008 to fill the gap created during the 2006 IBEW negotiations and in response to continued demographic pressures in the field workforce.

As mentioned earlier in Management Excellence, Utilities Strategy Project (page 86) , the USP in 2003 is another good example of the Company's efforts to address a specific demographic challenge and create a more efficient and effective organizational structure. As a result of that business initiative, the average age of Management and Exempt employees dropped from 46 to 44 years, and the overall number was reduced by approximately one-third. While this served its purpose at the time, given the changing nature of the business and the overall demographic challenge, these levels are not sustainable.

Services managed by Human Resources increased as a result of the integration of Terasen Gas and TGVI. The management of the TGVI existing collective agreement, pension and benefit plans were maintained and supported by the Terasen Gas Human Resources department with no increase to headcount. Shared services were implemented in December 2003 to provide advisory, payroll, benefit and pension governance and administration.

Following the acquisition of Terasen by Kinder Morgan Inc. ("KMI"), the Terasen, Human Resource functions were moved to the KMI Corporate Human Resources department and the Terasen Gas Human resources department. Three headcount and budget were transferred to Terasen Gas Inc. for services previously provided by Terasen. The remaining responsibilities previously held by three Terasen employees were managed through KMI. Following the subsequent acquisition of Terasen by Fortis Inc. ("Fortis"), those responsibilities previously managed by KMI were added to the responsibilities of the Terasen Gas Human Resources department without additional headcount.

(ii) Employee Development and Training

Employee development is another key pillar of Terasen Gas' strategy for managing demographic challenges. In addition to existing training and development opportunities such as the Distribution Apprentice program and the Engineer-in-Training program, a number of new initiatives have recently been introduced. There is a renewed emphasis on Leadership Development across the organization and the development of emerging leaders who are identified through the succession planning process. Targeted coaching, training, mentorship, and leadership programs have been introduced to build leadership bench strength across the organization. A new Manager-in-Training ("MIT") program was initially piloted in 2008 to expose aspiring managers, both internal and those recruited externally from other industries, to various components of our business. There are currently four MITs in the program who will go through a number of different job rotations in their first one to two years to give them a broad overview of our operations and better position them for a management position.

Employees also have the opportunity to access a variety of funding support mechanisms to support their personal and professional development. Tuition support of up to $3,000 per year is available for courses leading to undergraduate degrees and up to $10,000 per year for graduate degree programs. Employees can also request approval and financial support from their managers to participate in conferences and other forms of education that are linked to their employment at Terasen but are not part of a degree program. Finally, employees can also apply for funding through the Training Trust Funds that are in place for each affiliation, provided the programs meet the requisite criteria.

Employee development and training is essential to ensure ongoing safe, reliable and cost effective gas service. The demographics of the Distribution department's workforce resulted in additional training and employee development costs to replace cumulative years of knowledge and experience as a large portion of the workforce had reached retirement age. The additional employees added mid-2007 and early 2008 during the latter part of the PBR Period provided for orderly succession planning as retirements continued. The financial impact of these additions in terms of O&M payroll costs was primarily in the areas of recruiting, training and outfitting as well as in higher unit costs in both O&M and Capital activities.

From 2003 to 2006 formal training (classroom) costs averaged $1.0 million per year for the field workforce. In response to the demographic challenges and increasing retirements, Terasen initiated the apprenticeship program in 2007. Formal training costs rose to $1.8 million in 2007 and $2.4 million in 2008. The apprenticeships generally run two to three years and include a combination of formal and peer-to-peer (on-the-job) training.

The Distribution department has 108 employees who are presently eligible to retire with a full or partially reduced pension and, in addition, another 67 employees gain retirement eligibility from 2010 to 2013. These employees are in predominantly higher skill level positions which require a longer training and knowledge transfer period. We will continue to be proactive by planning for their inevitable replacement and ensuring new staff has progressed far enough along on the long learning curve to ensure a capable and competent workforce be maintained.

Terasen Gas is of the view that its focus on employee development and training has been a key contributor to the Company's success over the PBR Period. Terasen Gas intends to maintain and enhance its strong focus in this area in the future in order to continue its pursuit of Operational Excellence.

(iii) Employee Health and Wellness (Low Turnover and Reduction in Sick Days)

The availability of health and wellness programs and comprehensive employee benefits helps reduce employee turnover, resulting in a more stable employee population and reduced costs associated with attracting and training new employees. These programs and benefits also help attract good employees to work at Terasen Gas. The Company's overall employee turnover has been consistently below industry average for several years. For example, in 2007, Terasen Gas' voluntary turnover rate (not including retirements) was 3.53 per cent. This compared favorably to the rate for all sectors, which was 8.5 per cent, in addition to the rate for the transportation and utilities sector, which was 6.9 per cent. [111] High levels of employee turnover can be very costly (i.e. lost productivity, recruiting costs, training, overtime costs for replacement workers) with estimates typically ranging from 30 per centof annual wages for hourly employees up to 100 per cent and 150 per cent for management and senior management positions. Through our focus on retention as an objective which we actively manage, Terasen Gas has successfully kept these costs to a minimum.

[111] See Appendix F-3 for a copy of Compensation Planning Outlook 2008

Table B-1-8: Turnover Rates Remain Low

Turnover Rates (FTR Employees) 2002 to 2008	2002	2003	2004	2005	2006	2007	2008
Number of FTR Employees (as at Dec. 31)	1231	1372	1283	1254	1177	1189	1222
# Voluntary Terminations	20	17	84	34	47	42	27
# Involuntary Terminations	22	53	34	20	32	5	10
Total	42	70	118	54	79	47	37
% Voluntary Turnover	1.62%	1.24%	6.55%	2.71%	3.99%	3.53%	2.21%
% Involuntary Turnover	1.79%	3.86%	2.65%	1.59%	2.72%	0.42%	0.82%
Overall Turnover Rate	**3.41%**	**5.10%**	**9.20%**	**4.31%**	**6.71%**	**3.95%**	**3.03%**

As referenced on page 101, employee wellness is a measure on our corporate scorecard. One of the initiatives that has continuously contributed to reaching annual wellness objectives is our pro-active disability management program.

The Company's Human Resources department began encouraging more effective management of employee sick leave in 2001 by circulating quarterly sick leave reports to all managers. Since that time, sick leave has been reduced by 34 per cent, from an average of 7.7 days per employee per year, down to 5.1 in 2008. For the PBR Period, sick leave was reduced almost 10 per cent from 5.6 days per employee in 2003 to 5.1 days in 2008. This compares favourably to a Canada-wide industry average of 6 days/employee/year and 7.3 days for the transportation and utilities sector[112]. This achievement is due not only to targeted health and wellness initiatives, but also to the efforts of the Disability Management group and managers in addressing attendance management issues and encouraging early return to work programs within their areas of responsibility.

Manulife, the Company's insurer, has recognized the success of our pro-active approach to attendance management and early return to work programs with a reduction to our overall experience ratings and related premium costs. Estimated costs for absenteeism typically range between 1.5 and 2.5 times employee salary for direct and indirect costs (i.e. lost productivity, impact on other staff, cost of replacement workers). Terasen Gas continues to challenge employees to improvement via the Wellness indicator on the Corporate Scorecard, which is comprised largely of sick leave.

[112] See Appendix F-3 for a copy of Compensation Planning Outlook 2008

The Company's proactive approach to disability management over the PBR Period has allowed the Company to increase productivity and reduce costs associated with wellness days lost. In addition, our work in this area has allowed employees to remain engaged and motivated in their work.

(c) Compensation Management

For the purposes of compensation and benefits, Terasen Gas' workforce is separated into three primary groups:

- Executives;
- M&E employees; and
- Unionized employees represented by the IBEW and COPE

While the details of the compensation and benefits programs vary between these three groups, the Company applies the same philosophy and approach to compensation and benefits for all employees. This approach includes a total compensation package that rewards employees with competitive base salaries and wages, incentive compensation, benefits, and paid time-off.

The key objectives of the compensation and benefits program are to:

- Retain and motivate a qualified, diverse workforce by recognizing and rewarding achievement, contribution, and excellence;
- Attract a qualified, diverse workforce through a competitive compensation program;
- Reward by providing a consistently applied compensation program that meets the needs of a diverse workforce; and
- Promote continuous learning, leadership development and training while understanding that it is the responsibility of each employee to manage their own growth through development planning.

In order to achieve these objectives and to ensure the sustainability of employee benefit programs, Terasen Gas and its employees have adopted cost-shared pension and benefit arrangements. In addition, through ongoing review of our plans, Terasen Gas works towards continuous improvement by incorporating industry-determined best practices such as flexible work schedules and benefits, which enable employees to personalize the benefit plan to their own needs.

(i) Executive Employees

The Company's executive compensation program is designed to provide competitive levels of compensation, a significant portion of which is dependent upon individual and corporate performance. The compensation package is designed to retain and attract qualified and experienced executives as well as align the compensation level of each executive to that executive's level of responsibility. The objectives of base salary are to recognize market pay, and acknowledge competencies and skills of individuals. The objectives of the annual incentive plan are to reward achievement of short-term financial and operating performance objectives and focus on key activities and achievements critical to the ongoing success of Terasen Gas. Long-term incentive plans focus executives on sustained shareholder value creation.

The Company's executive compensation program involves four main elements (base pay, short term and long term incentive pay and benefits), which comprise a Total Rewards package. All of these factors support the needs of the business and its customers, and each element contributes to finding the balance on delivering successfully on both short and longer term objectives. In the 2003 revenue requirements decision (following a change in the accounting for stock options whereby the costs of stock option grants must be recorded as an operating expense under Canadian Generally Accepted Accounting Principles), the Commission ordered that stock option costs not be included in rates. The Company has not included, at this time, a request to recover stock option expense in customer rates. However, we do believe it appropriate to find agreement on the principle that market competitive compensation packages are costs reasonably recovered in rates from customers. Thereafter, the design of the compensation components is better left to the Company in order to ensure that they drive the overall success of outcomes which delivers sustained value over time to customers and shareholders. If the total cost is reasonable, the Commission should not prejudge the components and arbitrarily exclude one design option. Pending the outcome of such Decision, the Company reserves the right to bring forward stock option expense recovery in future Revenue Requirements proceedings.

As a general policy, Terasen Gas establishes base and incentive compensation targets so as to compensate executives at a level generally equivalent to the median level of a broad reference group of approximately 200 Canadian commercial industrial companies.

With the exception of the pension plan, benefits provided to the executives are based on the benefit program for M&E employees. Prior to June 1, 2007, all executives participated in the pension plan for M&E employees, in either a defined benefit or a defined contribution provision. Effective June 1 2007, all executives except Mr. Jespersen became members of a Group Registered Retirement Savings Plan ("RRSP"). The RRSP arrangement provides for equal contributions of 6 ½ per cent of salary by both the employee and employer up to the Canada Revenue Agency ("CRA") RRSP maximum limit. The Company makes notional contributions in excess of the RRSP maximum limit equal to 13 per cent of salary to a Supplemental Executive Retirement Plan ("SERP").

(ii) M&E Employees

As a general policy, Terasen Gas establishes base and incentive compensation targets at a level approximately equal to the median level of an established group of comparator companies in relevant markets. The comparator group consists mainly of other publicly-traded companies in the oil, gas and energy transportation industry, utilities, large B.C. employers in the private sector, as well as a broad cross-section of Canadian industry.

Pay increases and incentive opportunities for all employees are linked to individual and company performance which provides employees with an opportunity to increase their total compensation. Other factors, such as competitive market factors, current position in the salary range and budget guidelines may impact base pay.

Terasen Gas also offers an employee benefits program for M&E employees comprising pensions, health and welfare benefits, other work-related benefits and post-retirement benefits other than pensions. The employee benefits program is targeted to be competitive at the median level of an established group of comparator companies.

A key objective of Terasen Gas has been to provide a common benefits platform for all M&E employees, and to integrate the pension and benefit plans provided to TGVI M&E employees as a result of the 2002 acquisition of Centra Gas British Columbia. This strategy was adopted for several reasons, including simplified administration which reduces expenses and eases internal transfers. In addition, the rising cost of pensions and health care and other benefits is a concern for all Canadian businesses. We need to balance the needs of the business with those of our employees. Both are best served by a pension and benefits package that is sustainable in the future through employer and employee cost sharing, and which provides our employees with the flexibility to tailor benefits to meet the their needs. The provision of a flexible benefits plan generates a greater understanding of the benefits available to the employee and the associated costs, and promotes prudent consumerism.

We have made considerable progress in introducing a common pension and benefits platform for all of Terasen Gas' M&E employees:

- In 2003, the two legacy pension plans for TGVI employees were consolidated;
- In 2004, all M&E employees moved to the Terasen employee benefit plans and paid time-off schedules; and
- In 2007, all M&E employees enrolled in a new common employee benefits program comprising
    - a defined benefit pension plan with 50/50 employer/employee cost sharing;
    - a new employee savings plan; and
    - a revised cost shared flexible benefits plan and revised paid time-off schedules; and
    - a revised post retirement benefits program.

(iii) Unionized Employees

In 2006 and 2007, Terasen Gas reached five-year labour agreements with the IBEW and COPE respectively. These agreements introduced significantly greater flexibility in work management, and in implementing common flexible benefits and post-retirement benefits plans.

The following table shows the contracted increases in IBEW and COPE wages and salaries resulting from collective bargaining negotiations. These wage increases are reflected in the operating and capital costs of Terasen Gas throughout the PBR Period.

Table B-1-9: Union Wage Increases Average 2.9 per cent Per Year

Negotiated Wage Adjustments for Unionized Employees (2002-2009)

	2002	2003	2004	2005	2006	2007	2008	2009
IBEW	Apr 1 - 1.0%	Apr 1 - 3%	Apr 1 - 3%	Apr 1 - 3%	Sep 4 - 2.85%	Apr 1 - 2.5%	Apr 1 - 3%	Apr 1 - 3%
	Apr 5 - $500 lump sum							
COPE	Feb 1 - 2.5%	Oct 1 - 3%	Apr 1 - 3%	Apr 1 - 3%	Oct 1 - 2.85%	Dec 1 - 2.5%	Apr 1 - 3%	Apr 1 - 3%
	Jun 8 - 1.5% + $500 lump sum							

All IBEW and COPE employees belong to the Terasen Gas Inc. Pension Plan for IBEW and COPE Members. This plan is a jointly trusted and cost-shared defined benefit pension plan.

As with Terasen Gas' M&E employees, Terasen Gas has made considerable progress in negotiating harmonized benefit plans for active and retired IBEW and COPE employees:

(a) IBEW

- 2004 – All TGVI employees moved to the IBEW benefit plan.
- 2006 – Negotiated a change to benefit plans including retiree benefits.
- 2007 – All employees were provided with a choice of post-retirement benefits: either the traditional benefits plan or a new design that includes a Health Spending Account.
- 2011 – All IBEW will be enrolled in new flexible benefits and retiree benefits plans which are modeled on the plans provided to M&E employees Flex Plan. All new IBEW employees and existing employees who transfer to the new plans will be eligible for the Employee Savings Plan which provides a 3 per cent employer paid benefit.

(b) COPE

2007 – Negotiated a change to the benefit plans including retiree benefits. Implementation for both benefit plans commence January 2011 (modeled after the M&E Flex Benefit Plan).

(d) Summary of Employee Impacts over the PBR Period

Terasen Gas has consistently demonstrated its commitment to its employees throughout the PBR Period. As we reach the end of the PBR Period, we intend to continue to maintain our focus on maintaining a highly motivated and capable workforce, operating in a safe and efficient manner.

The Company has also demonstrated a prudent and responsible approach in managing overall costs, including headcount during the PBR Period. As is evidenced in the sections above, Terasen Gas has taken steps to create an efficient and effective talent management structure which has allowed us to meet our objectives of retaining, attracting, and motivating employees, which has in turn supported the Company's goal of achieving Operational Excellence.

(5) FINANCIAL RESULTS AND PERFORMANCE OVER THE PBR PERIOD

The PBR Agreement for the 2004 to 2009 period was structured to promote the alignment of interests between Terasen Gas' customers and its shareholder. The Company is of the view that this form of incentive regulation has proven to be a more efficient and effective model than the traditional model of regulation. The incentive mechanisms that were included in the PBR Agreement created a framework that encouraged the Company to actively pursue and achieve efficiencies, for the benefit of customers and the Company, without sacrificing service quality. Terasen Gas accepted the challenge that the incentives presented and throughout the PBR Period strove to capture all of the efficiencies available, while at the same time maintaining its commitment to service quality. The results achieved over the PBR Period were consistent with what was set out in the framework, and demonstrate the benefits that can be obtained from this form of rate making. Terasen Gas believes it realized all of the opportunities it had for efficiency gains during the PBR Period, and as a result, customers and the shareholder have shared equally in the benefits of these efficiencies.

There are several key components of the PBR Agreement that contributed to the financial results and performance of Terasen Gas through the PBR Period. These are discussed below in this section and include: The ESM, O&M Expense, Capital Expenditures, Gross Margin and Other Revenues, and Exogenous Factors. The SQIs were discussed page 114 in this Section.

(a) Earnings Sharing Mechanism during the PBR period

A key element of the PBR Agreement was the establishment of the earnings sharing mechanism. The ESM allowed for a 50:50 sharing between customers and the Company in earnings above and below the allowed ROE, beginning in 2004. The PBR structure and the earnings sharing mechanism were designed to encourage efficiencies over a longer term, and to enhance the opportunity for pay back on investments in efficiencies from realized savings. The earnings sharing encouraged continuous investments in efficiency throughout the full term of the PBR Period and compared to previous models, provided a stronger and expanded incentive to spur greater focus on capital expenditure efficiencies.

The main contributors to the earnings above ROE have been savings in O&M, and also the depreciation and rate base reductions resulting from lower capital expenditures. Total earnings sharing during the PBR Period has resulted in an estimated $69 million benefit to customers, as demonstrated in the following Table B-1-10.

Table B-1-10: Customers Realized $69 million in Savings as a result of the ESM

	Actual					Projection	
	2004	2005	2006	2007	2008	2009	Total
O&M Savings	$ 5.9	19.1	16.9	19.7	13.6	8.0	$ 83.2
Depreciation Savings	1.7	3.5	3.4	9.5	9.2	10.0	37.3
Rate Base (Earned Return)	(0.6)	(1.1)	5.7	4.3	2.9	5.7	16.9
Gross Margin	(2.0)	0.6	(1.9)	(2.5)	0.3	1.5	(4.1)
Other Revenue	(2.5)	(2.7)	(2.1)	(2.9)	(1.9)	(2.5)	(14.6)
2009 tax adj - overhead/CCA rates; SCP landscaping	-	-	-	-	-	12.6	12.6
Tax timing differences (mainly CCA)	1.2	1.6	(0.6)	1.8	1.2	0.9	6.1
Pre Tax Earnings Available for Sharing	$ 3.6	$ 21.0	$ 21.3	$ 29.9	$ 25.5	$ 36.1	$ 137.4
Customers' 50% Share of Earnings (pre-tax)	**$ 1.8**	**$ 10.5**	**$ 10.7**	**$ 15.0**	**$ 12.7**	**$ 18.0**	**$ 68.7**

Numbers shown are in $ millions

The components of earnings sharing have contributed to the success of the PBR Period from the customers' viewpoint, and also to the financial results of Terasen Gas. Excluding impacts of changes in income tax, the positive financial results of the Company resulted primarily from O&M savings and savings in capital expenditures, somewhat tempered by decreases in gross margin and other revenue from what was forecast. Each of these three items, including annual trends and their contribution to the financial results for the PBR Period are discussed below.

(b) Operations and Maintenance Expenses 2003 - 2009

During the term of the PBR Period, the allowed level of O&M expense to be included in the determination of rates each year, was based on a formula, using 2003 as the base year. The incentives inherent in the PBR Agreement provided the Company the significant opportunity to seek out all efficiency gains in its O&M expenses. This has meant that over the PBR Period there have been substantial savings that have been available for sharing with customers, which have helped to keep delivery rates down. This has also meant that the total O&M expenses projected for 2009 are well below the level included in the 2003 base year after adjusting for inflation, and O&M expense per customer in 2009 is also expected to be below the 2003 base year level. The Company views this evidence of significant efficiency gains as a clear demonstration of our commitment to continuous improvement and Operational Excellence.

In this O&M review section, the determination of the allowed O&M expenses will be described, followed by a review of the O&M savings on an annual basis. A discussion of the efficiency gains over the period will then precede a discussion of the O&M expenses in more detail on a departmental basis.

As part of the Annual Review process each year, the formula O&M for the upcoming year was calculated, for the determination of rates, by inflating the prior year's O&M for both customer growth and an efficiency-adjusted inflation factor. The efficiency adjustment factor (also referred to as the productivity factor) for 2004 and 2005 equaled 1/2 of the inflation factor, while for each of the subsequent four years (2006 – 2009) it was 2/3 of inflation. The calculation of the formula O&M each year is set out in the following Table B-1-11.

Table B-1-11: O&M Expense for the PBR Period was Formulaically Determined

Gross O&M Formula = (Previous Ye (Previous Year Adjusted Formula O&M[1]) X [(1+ Customer Growth) X (1+CPI-Adjustment Factor)] + Pension & Insurance Variance

($ thousands)	Approved 2003	Approved 2004	Adjusted 2004	Approved 2005	Adjusted 2005	Approved 2006	Adjusted 2006	Approved 2007	Adjusted 2007	Approved 2008	Adjusted 2008	Approved 2009
Adjusted Formula O&M		182,420	182,420	186,089	186,089	190,888	190,888	196,001	196,001	200,183	200,183	203,899
Customer Growth Factor		0.96%	1.15%	1.40%	1.56%	1.60%	1.92%	1.68%	1.44%	1.53%	1.17%	1.01%
CPI		1.70%	1.70%	2.00%	2.00%	2.20%	2.20%	2.00%	2.00%	2.00%	2.00%	2.10%
Adjustment Factor		-0.85%	-0.85%	-1.00%	-1.00%	-1.45%	-1.45%	-1.32%	-1.32%	-1.32%	-1.32%	-1.39%
Net Inflation Factor		101.82%	102.01%	102.41%	102.58%	102.36%	102.68%	102.38%	102.13%	102.22%	101.86%	101.73%
		185,740	186,089	190,575	190,888	195,394	196,001	200,657	200,183	204,624	203,899	207,424
Pension & Insurance Variance		2,245		11		1,526		(1,194)		(4,571)		(3,430)
Total including Ft Nelson	182,420	187,985		190,586		196,920		199,463		200,053		203,994
Less Ft Nelson	(684)	(696)		(714)		(732)		(752)		(767)		(778)
Gross Formula O&M Expense	**181,736**	**187,289**		**189,872**		**196,188**		**198,711**		**199,286**		**203,217**

[1]The formula O&M expense for each year is based on the previous year's formula O&M expense adjusted for actual customer growth

Source: Terasen Gas Inc. 2008 Annual Review of 2009 Revenue Requirements and Rates Section A Tab 5 Page 2

It is anticipated that by the end of six year PBR Period, that as a result of the Company's prudent management, the cumulative O&M savings available for sharing will be in the order of $83 million, as can be seen in Table B-1-12.

Table B-1-12: Gross O&M Savings Over the PBR Period are Expected to be $83 million[113]

	2004	2005	2006	2007	2008	Projection 2009	Total
Gross O&M as calculated under the PBR formula	$ 187.3	$ 189.9	$ 196.2	$ 198.7	$ 199.3	$ 203.2	$ 1,174.6
Actual Gross O&M	181.3	170.8	179.2	179.0	185.7	195.1	1,091.1
Total Gross O&M Available for Sharing	**6.0**	**19.1**	**17.0**	**19.7**	**13.6**	**8.1**	**83.5**
Variance in vehicle lease	(0.1)	-	(0.1)	-	-	(0.1)	(0.3)
O&M Contribution to Earnings Sharing Mechanism	**$ 5.9**	**$ 19.1**	**$ 16.9**	**$ 19.7**	**$ 13.6**	**$ 8.0**	**$ 83.2**

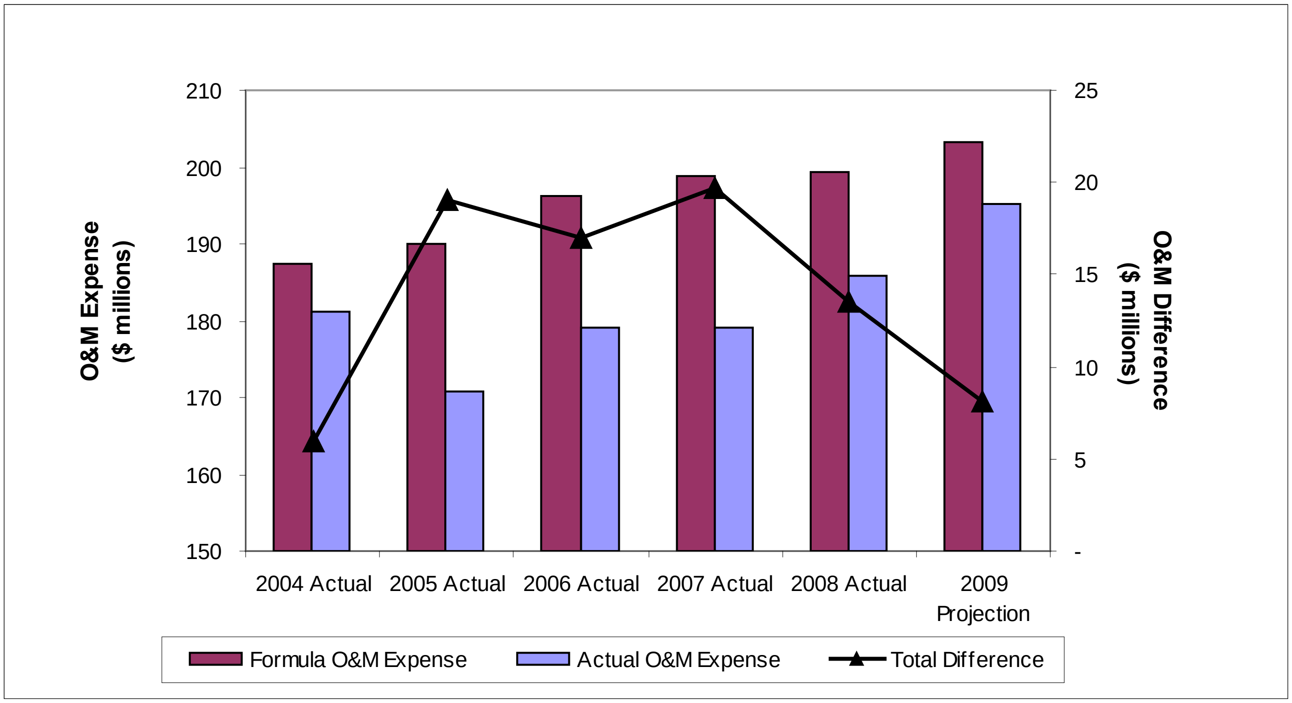
Amounts are in $ millions

This significant achievement has been realized through the Company's sustained focus on continuous improvement and Operational Excellence and the pursuit of efficiencies, during a period of significant change as discussed in Part III, Section A . A significant accomplishment in this regard was the execution of the USP in 2004, as described on page 86.

The following chart displays the same information graphically, and demonstrates that the O&M savings reached their maximum in the years 2005 to 2007, after the USP was implemented. The graph also highlights that the efficiency factors built into the PBR Period which, as previously mentioned, increased to 2/3 of CPI for the last four years of the term, result in diminishing savings as that level of efficiency is not sustainable over a longer period of time.

113 See Appendix F-1 for a copy of actual O&M Expenditures History

Figure B-1-13: Annual Gross O&M Savings Is Declining Over the last part of the PBR Period



In addition to the USP, the Company was able to gain efficiencies in the earlier years of the PBR Period through a number of other means:

- The implementation of large scale Information Technology solutions;
- Internal departmental reorganizations and streamlining;
- Deferring activities and related costs where safe and prudent to do so, particularly where the activities were of a cyclical nature;
- A strong focus on achieving a lower bad debt experience rate;
- Leaving vacancies unfilled, both planned and unplanned due to difficulties in attracting and retaining specific jobs in a strong economic cycle; and
- The utilization of new technology that allowed for reduced manpower.

These savings can only be achieved once, or can only be sustained for a limited period of time before activities need to be resumed and costs need to be incurred. Accordingly, the level of O&M savings being achieved, relative to the formula driven allowed expenses, in the later years of the PBR Period has decreased, as to be reasonably expected, as these opportunities for efficiency gains have been exhausted and actual labour inflation is significantly higher than the productivity adjusted inflation factor included in the formula.

As stated above, the formula driven allowed O&M for the PBR Period was based on the approved O&M expense for 2003. As such the 2003 base level of O&M expense both in total and on a per customer basis, forms the logical basis for the comparison of the efficiency gains realized in the Company's actual O&M expenditures over the PBR Period. The following table compares annual gross O&M expense starting with the 2003 base year, with actuals for 2004 through 2009. This has been done in nominal dollars as well as on an inflation-adjusted (real $2009) basis.[114]

Table B-1-13: 2009 Total Gross Real O&M Expenses are Lower Than 2003 Base

	Decision	Actual					Projection
	2003	2004	2005	2006	2007	2008	2009
Total Gross Nominal O&M Expenses ($ millions)	$ 181.7	$ 181.3	$ 170.8	$ 179.2	$ 179.0	$ 185.7	$ 195.1
Total Gross Real O&M Expenses ($ millions)	$ 204.7	$ 200.7	$ 185.5	$ 190.4	$ 186.4	$ 189.6	$ 195.1
Average Number of Customers	770,368	779,498	791,647	803,686	817,480	825,957	833,798

Gross Real O&M expenses of $195.1 million projected for 2009 are approximately 5 per cent lower than the 2003 Decision in real dollars ($204.7 million). This is despite the actual labour inflation during the term of the PBR Period (approximately 3 per cent) being a full percentage point higher than the average CPI from the Annual Reviews, that has been used to adjust to the Real O&M expenses. This additional labour inflation has been offset through the productivity improvements and efficiency gains during the PBR Period.

More importantly, when considered on a per customer basis, the efficiency gains achieved in the O&M expenses are even more significant. The O&M per customer in 2009 is $234, which represent a $2 reduction in the seven years back to the 2003 base year. On a real basis the O&M per customer is 12 per cent lower in 2009 ($234) as compared to the 2003 base year ($266).

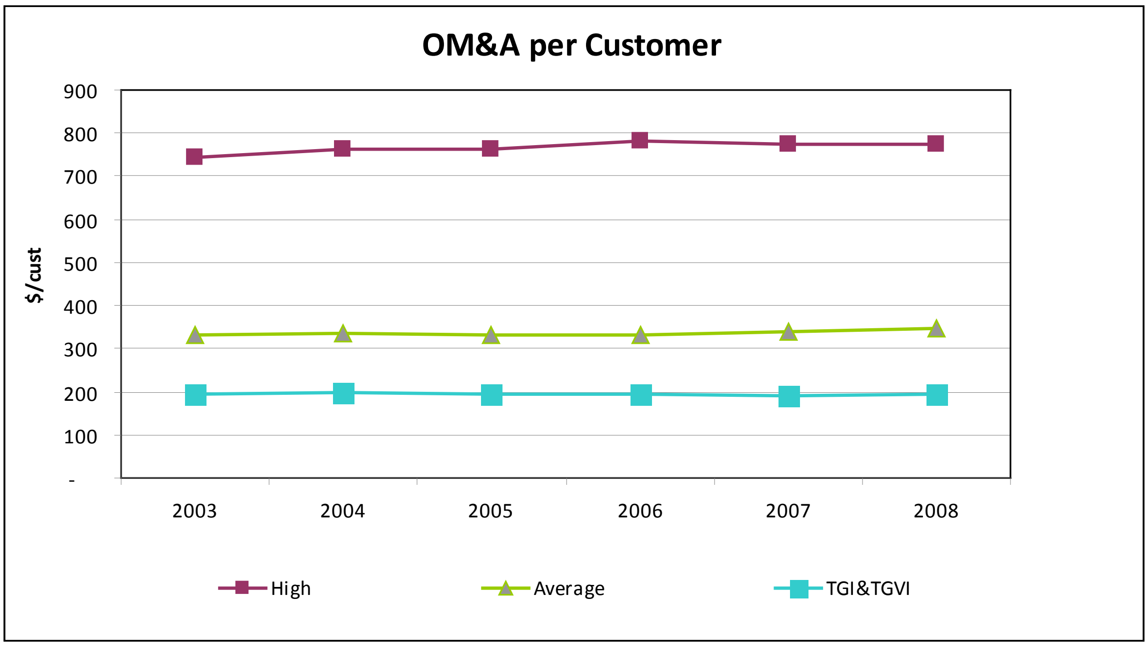
Table B-1-14: 2009 Gross O&M Expense per Customer is Lower Than 2003 Base

	Decision	Actual					Projection
	2003	2004	2005	2006	2007	2008	2009
Formula (approved)	$ 236	$ 240	$ 240	$ 244	$ 243	$ 241	$ 244
Actual - nominal dollars	$ 236	$ 233	$ 216	$ 223	$ 219	$ 225	$ 234
Actual - real dollars	$ 266	$ 258	$ 234	$ 237	$ 228	$ 230	$ 234

[114] See Appendix F-4 for a copy of Inflation History and Outlook

Terasen Gas prides itself in having one of the lowest O&M cost per customer measures for natural gas utilities in Canada. A recent survey of comparable natural gas utilities in Canada (refer to Table B-1-14 below) based on publicly available information from regulatory filings and corporate annual reports ranks Terasen Gas including TGI and TGVI as one the lowest O&M (net of overhead capitalized) per customer out of eight companies surveyed. Due to the availability of data and for the purposes of comparison, a net of overhead capitalized O&M measure was used instead of a gross O&M measure excluding capitalized overhead.

Figure B-1-14: Terasen Gas is among the Lowest O&M per Customer



The Company views this as a significant accomplishment, and a demonstration of the substantial efficiency gains it has made over the PBR Period in its pursuit of Operational Excellence, which the Company intends to continue to pursue in the future. On a departmental basis, the trend in the level of gross O&M over the PBR Period, adjusted for inflation, further demonstrates the productivity and efficiency gains that were realized.

Table B-1-15: Historical O&M Expenses by Department

Department	Decision 2003 [1]	Actual 2004 [2]	Actual 2005	Actual 2006	Actual 2007 [3]	Actual 2008	Projection 2009
Distribution	$ 31.7	$ 31.4	$ 32.8	$ 31.7	$ 33.4	$ 37.0	$ 37.0
Gas Supply And Transmission	16.0	13.4	15.1	13.7	13.7	14.7	16.9
Marketing & Business Development	60.5	58.4	58.1	60.9	60.7	63.1	66.6
Business and IT Services	35.4	30.4	32.6	33.7	35.4	35.7	39.1
Human Resources and Operations Governance	8.1	6.0	5.9	6.4	7.0	7.3	8.4
Finance and Regulatory Affairs	8.6	6.6	7.4	7.1	7.8	8.7	9.6
President & CEO	21.4	35.1	18.9	25.7	21.1	19.3	17.5
Total Gross Nominal O&M Expenses	**$ 181.7**	**$ 181.3**	**$ 170.8**	**$ 179.2**	**$ 179.0**	**$ 185.7**	**$ 195.1**
Distribution	$ 35.7	$ 34.8	$ 35.6	$ 33.7	$ 34.8	$ 37.8	$ 37.0
Gas Supply And Transmission	18.0	14.8	16.4	14.6	14.3	15.0	16.9
Marketing & Business Development	68.1	64.7	63.1	64.7	63.2	64.4	66.6
Business and IT Services	39.9	33.6	35.4	35.8	36.8	36.4	39.1
Human Resources and Operations Governance	9.1	6.7	6.4	6.8	7.3	7.4	8.4
Finance and Regulatory Affairs	9.7	7.3	8.0	7.5	8.1	8.9	9.6
President & CEO	24.1	38.8	20.5	27.3	21.9	19.7	17.5
Total Gross Real O&M Expenses	**$ 204.7**	**$ 200.7**	**$ 185.5**	**$ 190.4**	**$ 186.4**	**$ 189.6**	**$ 195.1**

Notes:
All amounts are in $ millions
Gross O&M expenses are before removal of capitalized overheads and vehicle lease expenses.
Real O&M expenses have been adjusted for the effects of CPI inflation, as filed in the Terasen Gas Annual Reviews during the PBR period.
[1] 2003 Decision O&M of $181.7 million has been adjusted fto include $5.5 million of TPIP
[2] 2004 Gross O&M of $181.3 million includes $9.6 million of restructuring costs in the President & CEO department
[3] Terasen Gas Squamish was amalgamated with Terasen Gas January 1, 2007. Terasen Gas Squamish O&M is therefore not included for the years 2003-2006.

The following sections describe the major trends and challenges experienced by the seven departments over the PBR Period as compared to the 2003 base. The scope of responsibility for each of these departments has been described on page 86.

(i) Distribution

The Distribution department is committed to Operational Excellence in the safe, efficient and reliable delivery of natural gas to homes and businesses throughout BC. Since the introduction of PBR Agreements to Terasen Gas in the mid 1990s, the Distribution department has been proactively managing cost pressures and realizing productivity gains. Many large scale "one-time" productivity opportunities were realized from 1997 to 2002. The initiatives included:

- Workforce reductions and efficiency measures made possible by the consolidation of facilities, particularly to the Surrey Operations Centre.
- Large scale information technology solutions to modernize and centralize labour intensive processes; namely AM/FM, Integrated Resource Management ("IRM") and Work Management System/Preventive Maintenance ("WMS/PM").

With some of the larger productivity initiatives exhausted in the preceding years, the result has been fewer significant opportunities during 2003 to 2009, with integration with TGVI being the only notable exception. This has contributed to the Distribution department O&M increase in nominal dollars over the PBR Period as fewer productivity gains are available to offset rising cost pressures. However, on an inflation-adjusted (real) basis, costs have declined over the period on a per customer basis. [115]

Table B-1-16: Distribution Department O&M in Real Terms Has Declined Over the PBR Period

	Decision 2003	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Projection 2009
Distribution Nominal O&M ($ millions)	$ 31.7	$ 31.4	$ 32.8	$ 31.7	$ 33.4	$ 37.0	$ 37.0
Distribution Real O&M ($millions)	$ 35.7	$ 34.8	$ 35.6	$ 33.7	$ 34.8	$ 37.8	$ 37.0
Real O&M per Customer	$ 46	$ 45	$ 45	$ 42	$ 43	$ 46	$ 44

Contributing factors to the increase in nominal dollars over the PBR Period are cost pressures above general inflation CPI, system integrity and compliance requirements, demographic challenges and emergency response requirements.

(a) Higher than General CPI Cost Pressures

Over 80 per cent of the O&M requirements of the Distribution department relate to labour and vehicle costs where we have experienced inflationary pressures in excess of CPI. A highly competitive labour market has led to cumulative wage increases exceeding CPI by 6 per cent from 2003 to 2009, resulting in O&M increases of approximately $2 million. During this period, the Distribution department proactively managed and minimized these inflationary pressures by broadening the skill sets of our employees. This resulted in reduced stratification of work and created offsetting efficiencies. Inflationary pressures in excess of CPI will continue into 2010 and 2011.

Although line heater fuel is a relatively small component of the Distribution department's overall budget, total expenditures during the PBR Period have increased, driven primarily by higher cost of gas. Since 2003, the cost of gas for line heater fuel has increased approximately 50 per cent from $4.70 per GJ to $6.60 per GJ. The Distribution department will continue to proactively manage these escalating energy costs by installing more efficient equipment while also taking into consideration the increased maintenance requirements typically encountered with more sophisticated equipment.

(b) System Integrity and Compliance

Laws, code requirements, and accepted industry operating practices are also major drivers of the Distribution department's O&M costs. As the natural gas industry matures, system age becomes a more prominent consideration with oversight agencies, resulting in Code enhancements to ensure system

[115] See Appendix F-4 for a copy of Inflation History and Outlook

integrity is maintained. An example of the significance of changes in laws, standards and codes are the changes to 'CSA Z662 Oil and gas pipeline systems'.

The Distribution department maintains a strong focus on System Integrity and will continue to enhance programs in response to code changes in the future to ensure that aging infrastructure will not compromise safety and reliability.

(c) Demographic Challenges

Employee development and training is essential to ensure ongoing safe, reliable and cost effective gas service. The demographics of the Distribution department's workforce have resulted in additional training and employee development costs to replace cumulative years of knowledge and experience as a large portion of the workforce has reached retirement age. Additional employees were added mid-2007 and early 2008 during the latter part of the PBR Period to provide for orderly succession planning as retirements increased. The financial impact of these additions in terms of O&M payroll costs was primarily in the areas of training and outfitting as well as in higher unit costs in both O&M and Capital activities.

From 2003 to 2006 formal training (classroom) costs averaged $1.0 million per year for the field workforce. In response to demographic challenges and increasing retirements, Terasen initiated an apprenticeship program in 2007. Formal training costs rose to $1.8 million in 2007 and $2.4 million in 2008. The apprenticeships generally run three years and include a combination of formal and peer-to-peer (on-the-job) training.

The Distribution department has 108 employees who are presently eligible to retire with a full or partially reduced pension and, in addition, another 67 employees gain retirement eligibility from 2010 to 2013. These employees are in predominantly higher skill level positions which attract a longer training and knowledge transfer period. We will continue to be proactive by planning for their inevitable replacement and ensuring new staff has progressed far enough along on the long learning curve to ensure a capable and competent workforce can be maintained.

(d) Emergency Response

Emergency Response staff must be in place throughout Terasen Gas' service area (i.e. Fire Department concept). To the extent these employees can be engaged in installation and operations activities, it serves to maintain their skill sets and dilute the standby costs of emergency preparedness and response.

The Distribution department is impacted by variations in synergies as construction and operations activities increase and decrease from year to year. The recent pronounced downturn in new construction caused a significant loss in synergies and a corresponding increase to first response standby/idle-time costs in 2008 and 2009.

First response standby/idle time costs averaged $3.8 million over the period 2005-2007 when new construction was at high levels relative to late 2008 and 2009. First response standby/idle time actual costs for 2008 were $4.4 million with 2009 forecasted at $4.5 million. The Distribution department has mitigated the magnitude of this cost pressure by sharply curtailing work previously assigned to installation contractors and by ramping up other long-term capital programs. The Distribution department will continue to proactively manage this area to minimize financial impacts but will continue to be exposed to this cost pressure in the future.

Although the customer growth and CPI escalators in the 2004 -2009 PBR formula were in alignment with actual cost pressures within Distribution, they did not adequately offset all cost pressures particularly in the latter years of the PBR Period. The productivity improvement factor described in the 2004 PBR Period incented Distribution to manage cost pressures; to defer activities and expenditures to the extent it was prudent and safe to do so; and to implement sustainable productivity gains such as integration with TGVI as well as continued deployment of new information technology. Terasen customers benefited from the incentive mechanism during the PBR Period and will continue to enjoy the benefits of retained efficiencies in 2010 and 2011.

(ii) Gas Supply and Transmission

The O&M costs[116] for the Gas Supply and Transmission department, in both nominal and inflation-adjusted (real) dollars are shown in the table below. [117] The Gas Supply and Transmission department O&M has increased over the PBR Period, however, on an inflation-adjusted (real) basis, costs have declined over the period, both in terms of total dollars and on a per customer basis.

[116] Expenses related to Core Market Administration are covered in Part III, Section C, Tab 5, Cost of Gas.
[117] See Appendix F-4 for a copy of Inflation History and Outlook

Table B-1-17: Gas Supply and Transmission Department O&M in Real Terms Has Declined Over the PBR Period

	Decision	Actual					Projection
	2003	2004	2005	2006	2007	2008	2009
Gas Supply And Transmission	$ 10.5	$ 9.3	$ 9.1	$ 9.2	$ 9.6	$ 10.2	$ 11.2
TPIP	5.5	4.1	6.0	4.5	4.2	4.5	5.8
Nominal GS&T Total O&M Expenses	**$ 16.0**	**$ 13.4**	**$ 15.1**	**$ 13.7**	**$ 13.7**	**$ 14.7**	**$ 16.9**
Gas Supply And Transmission	$ 11.8	$ 10.3	$ 9.9	$ 9.8	$ 10.0	$ 10.4	$ 11.2
TPIP	6.2	4.6	6.5	4.8	4.3	4.6	5.8
Real GS&T Total O&M Expenses	**$ 18.0**	**$ 14.8**	**$ 16.4**	**$ 14.6**	**$ 14.3**	**$ 15.0**	**$ 16.9**
Real O&M per Customer	**$ 23**	**$ 19**	**$ 21**	**$ 18**	**$ 17**	**$ 18**	**$ 20**

Amounts are in $ millions except real O&M per customer

Variations in the level of the Gas Supply and Transmission department O&M have been driven by changing levels of spending on TPIP programs by year, as discussed in the annual reports submitted to the BCUC . Excluding these amounts, departmental O&M has varied from $9.8 million in 2007 to $11.2 million in 2009.

There are 3 main contributors to the variations in Gas Supply and Transmission costs over the PBR Period. These are compressor/LNG fuel costs, staffing challenges and integrity management. Each are discussed below.

(a) Compressor/LNG Own Use Fuel

Compressor and LNG fuel use costs have increased $0.6 million from 2003 to 2009, driven primarily by gas costs as explained in Part III, Section C, Tab 5 – Cost of Gas. The majority of this increase occurred in the years 2008 and 2009.

(b) Staffing Challenges

Year to year fluctuations were caused by challenges in attracting and retaining skilled workers, resulting in scheduling delays to lower priority work. With Transmission now back to required headcount, the backlog is in the process of being cleared and is demonstrated in the increase in spending projected for 2009. Safety and reliability were not at risk during this period.

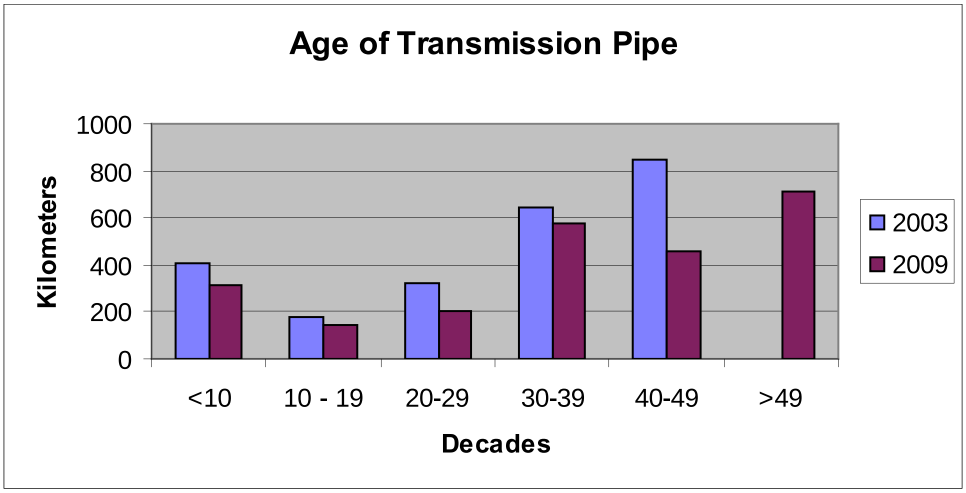
(c) Integrity Management

Gas Supply and Transmission maintains a strong focus on System Integrity and enhances integrity management programs in response to four drivers to ensure that aging infrastructure does not compromise safety and reliability. During 2007/2008, the Company developed and refined its Integrity Management Plan which was described in this Section on page 126.

Increases of approximately $0.2 million and $0.3 million are reflected in 2008 and 2009 costs to respond to these four drivers:

- Inflationary costs i.e. increased internal/external labour costs, materials costs, etc;
- Growth i.e. more services to inspect/maintain, more ROW to clear, more external activity to control/monitor;
- Asset age which increases risk profile i.e. more frequent inspections, more unplanned maintenance (repair), more replacements; and
- New or changed code requirements.

Figure B-1-15: Aging Transmission System



One half of the total mainline transmission pipeline length is over 40 years old. The level of expenditure required to operate and maintain older segments to the required standard of safety and reliability has grown due to the need for selective asset replacement or repair, as identified by regularly scheduled internal inspections and assessments of pipe condition. Figure B-1-15 displays the number of kilometers and age of Transmission pipelines on the Terasen Gas system.

In summary, Gas Supply and Transmission costs have risen only slightly in real terms due primarily to gas costs and the maintenance of asset integrity to ensure safe and reliable service. As assets continue to age and integrity programs evolve due to new codes and regulation as well as industry experience, Gas Supply and Transmission anticipates moderate increases to operating costs outside of own-use fuel.

(iii) Marketing and Business Development

The O&M costs for the Marketing and Business Development department, in both nominal and inflation-adjusted (real) dollars are shown in the table below. [118] There are three main components to the O&M costs – the costs related to the Customer Contact contract, bad debts expense, and the ongoing departmental expenses. The Marketing and Business Development department O&M has increased over the PBR Period, however, on an inflation-adjusted (real) basis, costs have declined over the period, both in terms of total dollars and on a per customer basis.

Table B-1-18: Marketing and Business Development Department O&M over the PBR Period

	Decision	Actual					Projection
	2003	2004	2005	2006	2007	2008	2009
Customer Contact - ABSU contract	$ 42.7	$ 42.7	$ 43.6	$ 44.2	$ 45.4	$ 46.4	$ 46.8
Bad Debt Expense	5.0	4.9	3.3	4.3	3.4	3.7	5.0
Other	12.7	10.8	11.2	12.5	11.9	13.0	14.8
Nominal Marketing O&M Expenses	**$ 60.5**	**$ 58.4**	**$ 58.1**	**$ 60.9**	**$ 60.7**	**$ 63.1**	**$ 66.6**
Customer Contact - ABSU contract	$ 48.1	$ 47.3	$ 47.3	$ 46.9	$ 47.2	$ 47.4	$ 46.8
Bad Debt Expense	5.7	5.4	3.6	4.6	3.5	3.8	5.0
Other	14.3	11.9	12.2	13.3	12.4	13.3	14.8
Real Marketing O&M Expenses	**$ 68.1**	**$ 64.7**	**$ 63.1**	**$ 64.7**	**$ 63.2**	**$ 64.4**	**$ 66.6**
Real O&M per Customer	**$ 88**	**$ 83**	**$ 80**	**$ 81**	**$ 77**	**$ 78**	**$ 80**

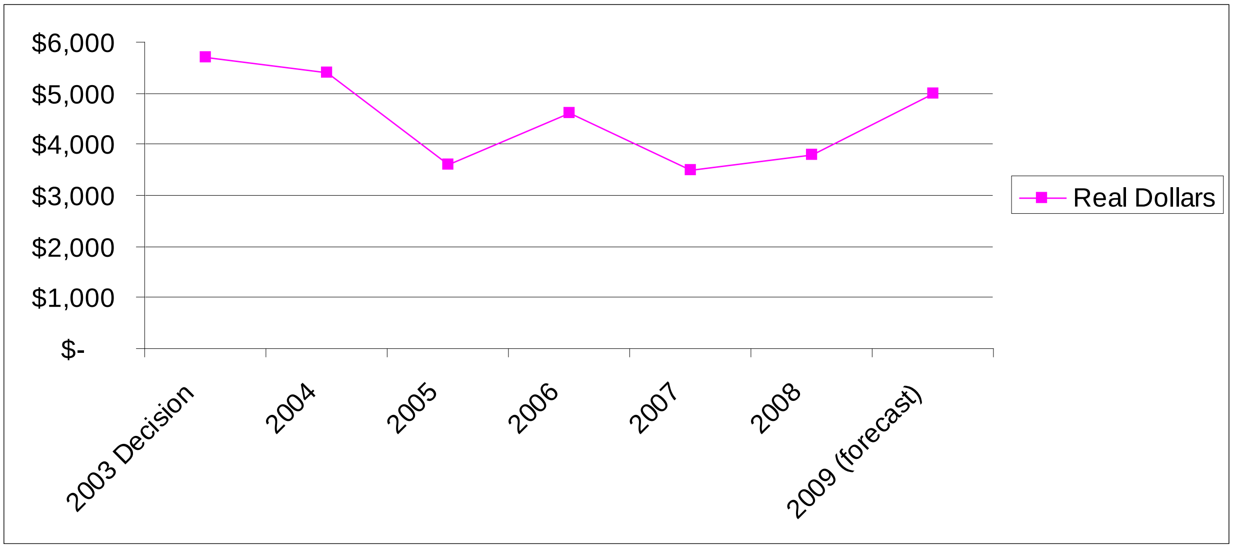
Amounts are in $ millions except real O&M per customer

The increase in the Customer Contact contract costs over the PBR Period is the result of the automatic one-half of inflation adjustment made each year and by the addition of new customers to the system.

Other than the contracted costs built into the Customer Contact contract, the largest single area of costs incurred by the Marketing and Business Development department is bad debt expense for the residential and commercial customers. In the 2003 decision, the bad debt expense was set at $5.7 million (real dollars) for residential and commercial customers. The bad debt experience rate in total real dollars is shown in the following table:

118 See Appendix F-4 for a copy of Inflation History and Outlook

Figure B-1-16: Bad Debt Experience has Improved Over the PBR Period



As noted by the Company during the review of its 2003 RRA, Terasen Gas at the time was experiencing high bad debt in part as a result of the significant increase in the cost of commodity experienced in 2001 and 2002. However, over the PBR Period, Terasen gas has been able to reduce the bad debt experience significantly. Success in this area can be attributed to two items:

1. Repatriation of billing and bad debt management from BC Hydro and subsequent implementation of Terasen Gas bad debt policies;
2. Positive economic conditions until the fall of 2008.

Terasen Gas repatriated bad debt and billing activities from BC Hydro in 2002. Bad debt practices as part of the BC Hydro billing revolved around the need for electricity rather than gas. The Company is of the view that some customers are more motivated to pay for their electricity than for their gas. By being part of BC Hydro's billing and bad debt process, customers would pay their bill to ensure they received electricity service however this benefited Terasen Gas as its customers also paid as a result of this practice. The prior joint billing arrangement ensured that electricity and gas collection activities were pursued jointly. After repatriation, bad debt experience rates climbed and as noted in the 2003 RRA, Terasen Gas had to design new meter to cash and bad debt procedures and processes. The most significant change for customers was the move from bi-monthly to monthly billing and the collections timeline required to accommodate this change. In part due to Terasen Gas's new bad debt management processes, bad debt experience rates decreased over the term of the PBR Agreement. Some changes to the bad debt processes and practices included:

- Decreasing the time before Terasen Gas would act on arrears. Terasen Gas now acts on residential arrears that exceed $100 and 30 days via reminders, notices and outbound calls. By acting on arrears early, before a customer has built up a significant arrears balance, Terasen Gas has noticed that customers are more likely to be able to make arrangements to pay off bad debt before the account reached the "service disconnection" stage; and
- Terasen Gas also works with customers to establish arrears payment arrangements that include longer payback timeframes. This often allows customers to repay outstanding amounts in a manageable fashion rather than face a service disconnection.

For the majority of the PBR Period, British Columbia, and the rest of Canada, was enjoying a time of prosperity. BC's unemployment rate was low, and as such customers would be more likely to be able to pay off any arrears balance. This is significant in that it is much easier for a customer to pay for arrears if they are employed or there is at least the prospect of employment. If employment or the prospect of employment drops, typically arrears will increase while at the same time, customers will be less likely to be in a position to pay for arrears.

The changes in the "Other" category in Table B-1-18, relate primarily to changes in headcount. Initial reductions in headcount were as a result of changes in focus of staff and efficiencies gained through the amalgamation of TGVI and Terasen Gas. In more recent years, sales, account management and business development staff have been added to the Customer Solutions and Services group, and additional staff have been added to the Customer Care and Services group. The additions of these staff were to address and meet changing customer expectations.

We believe that the costs incurred by the Marketing and Business Development Department over the PBR Period were prudent and sufficient to meet customer expectations. However, as customer expectations and needs change and grow, the Marketing and Business Development Department will require incremental funds to meet these challenges.

(iv) Business and IT Services

The O&M costs for the Business and IT Services department, in both nominal and inflation-adjusted (real) dollars are shown in the table below. [119] The departmental expenses are made up of three distinct groups – IT and Business Services, Operations Engineering and Operations Support. The Business and IT Services department O&M has decreased over the PBR Period by approximately 2 per cent on an inflation-adjusted (real) basis. Costs have also declined over the period on a per customer basis, representing significant efficiency gains.

[119] See Appendix F-4 for a copy of Inflation History and Outlook

Table B-1-19: Business and IT Services Department O&M Has Declined over the PBR Period

	Decision 2003	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Projection 2009
IT and Business Services	$ 19.8	$ 17.3	$ 18.3	$ 19.3	$ 20.7	$ 20.5	$ 22.4
Operations Engineering	7.9	6.7	7.5	7.7	8.0	8.3	9.2
Operations Support	7.6	6.4	6.8	6.6	6.7	6.8	7.5
Business & IT Services Nominal O&M	**$ 35.4**	**$ 30.4**	**$ 32.6**	**$ 33.7**	**$ 35.4**	**$ 35.7**	**$ 39.1**
IT and Business Services	$ 22.3	$ 19.1	$ 19.9	$ 20.5	$ 21.5	$ 20.9	$ 22.4
Operations Engineering	8.9	7.4	8.2	8.2	8.4	8.5	9.2
Operations Support	8.6	7.1	7.4	7.1	6.9	7.0	7.5
Business & IT Services Real O&M	**$ 39.9**	**$ 33.6**	**$ 35.4**	**$ 35.8**	**$ 36.8**	**$ 36.4**	**$ 39.1**
Real O&M per Customer	**$ 52**	**$ 43**	**$ 45**	**$ 45**	**$ 45**	**$ 44**	**$ 47**

Amounts are in $ millions except real O&M per customer

A description of the functions performed for each of the three departments within the Business and IT Services departments was set out on page 92 of the Application. An explanation of the historical O&M expense for each of the three departments follows.

(a) IT and Business Services

The Facilities department, responsible for building and facility maintenance, forms part of the IT and Business Services department. Increases for the Facilities department expenses during the PBR Period have been driven by property and service contracts (i.e. janitorial, landscaping, security, etc) renewals increases and increased expenses to service aging facilities.

IT costs have been increasing to provide support and maintenance of applications that have been implemented in the Company, driven by the operating departments' changing business needs.

(b) Operations Engineering

Operations Engineering operating costs increased in the 2004/2005 timeframe primarily as a result of changes in activity levels. After the integration of TGVI under the USP initiative, increases in activities and costs were necessary to support TGVI. The activities include drafting and mapping services and processing of BCOneCall tickets. The increase in costs recorded in Operations Engineering was recovered through shared services in the President and CEO's department instead of being directly credited to Operations Support.

The second significant increase in activity levels occurred in 2009 and was caused by a change in the BC Safety Authority – Gas Safety Regulation. Under the new regulation, Terasen Gas has only 2 days (instead of 3 days as per the old regulation) to provide gas system information requested by a third party. Consequently, additional staff was hired in 2009 to meet this new requirement.

(c) Operations Support

Between 2003 and 2008, O&M spending within Operations Support has been relatively constant, with a significant decrease in 2004 relating to the closure of the leased Bainbridge and Commerce Court measurement facilities and consolidation of those activities in Penticton and Surrey, and a smaller decrease occurring in 2006 related to the merger of the measurement and supply chain departments resulting in decreased supervisory and overhead costs. However, spending for 2009 is forecasted to increase due to a combination of items, including inflation in excess of CPI, increased repair activity for tools and equipment and a decrease in third party meter services net revenue. In addition, approximately one third of the incremental increase in O&M spending observed in 2009 relates to the commencement of a shared services agreement between Terasen Gas and TGVI for meter services. This results in the related revenues being included in shared services in the President and CEO's department instead of being directly credited to Operations Support.

As supported by stability of O&M costs on an inflation-adjusted (real) basis during the PBR Period, the Business and IT Services departments have provided the necessary supporting services while containing costs through efficiency gains, both on an overall dollar basis and on a per customer basis.

(v) Human Resources and Operations Governance

The O&M costs for the Human Resources and Operations Governance ("HROG") department, in both nominal and inflation-adjusted (real) dollars are shown in the table below. [120] This department is made up of three main areas – human resources, environment and occupational health and safety, and engineering governance and fleet services. The HROG department O&M on a nominal basis has increased over the PBR Period, however, on an inflation-adjusted (real) basis, costs have declined over the period, both in terms of total dollars and on a per customer basis.

Table B-1-20: Human Resources and Operations Governance Department Real O&M declined over the PBR Period

	Decision	Actual					Projection
	2003	2004	2005	2006	2007	2008	2009
Human Resources	$ 5.6	$ 4.5	$ 4.4	$ 5.1	$ 5.8	$ 6.1	$ 6.8
Environment & Occupational Health & Safety	2.0	1.4	1.3	1.2	1.1	1.2	1.5
Engineering Governance & Fleet Services	0.6	0.1	0.1	0.1	0.1	0.0	0.1
HR & Operations Governance Nominal O&M	**$ 8.1**	**$ 6.0**	**$ 5.9**	**$ 6.4**	**$ 7.0**	**$ 7.3**	**$ 8.4**
Human Resources	$ 6.3	$ 5.0	$ 4.8	$ 5.4	$ 6.0	$ 6.2	$ 6.8
Environment & Occupational Health & Safety	2.3	1.5	1.4	1.2	1.1	1.2	1.5
Engineering Governance & Fleet Services	0.6	0.1	0.1	0.1	0.1	0.0	0.1
HR & Operations Governance Real O&M	**$ 9.1**	**$ 6.7**	**$ 6.4**	**$ 6.8**	**$ 7.3**	**$ 7.4**	**$ 8.4**
Real O&M per Customer	**$ 12**	**$ 9**	**$ 8**	**$ 8**	**$ 9**	**$ 9**	**$ 10**

Amounts are in $ millions except real O&M per customer

[120] See Appendix F-4 for a copy of Inflation History and Outlook

The O&M of the HROG department decreased significantly from 2003 to 2004 due to implementation of the USP. Between the years 2004 and 2008 O&M was relatively flat except for inflationary increases, and headcount during this time period remained fairly stable fluctuating at times by one or two positions. In 2009, HROG O&M increased to address issues relating to code compliance, additional costs for recruiting and employee support, and the additional costs related to training of IBEW field personnel.

As shown in Table B-1-20 above, HROG real O&M per customer between 2003 and 2008 declined $3, from $12 to $9, while the projection for 2009 is $10 per customer. Similarly, Table B-1-20 below shows that HROG real O&M per FTE employee went down by $1,088, from $7,654 to $6,566, for 2003-2008, and the 2009 projection is $6,774 which is still $880 below 2003 levels.[121]

Table B-1-21: HROG O&M per FTE has Declined

	2003	2008	2009
HROG O&M ($ millions)	$ 9.1	$ 7.4	$ 8.4
FTE	1,189	1,127	1,250
Real O&M per FTE	$ 7,653	$ 6,566	$ 6,720

These incremental costs shown for 2009 are reasonable and consistent with the pressures being faced by HROG as outlined in previous sections of this application.

(vi) Finance and Regulatory Affairs

The O&M costs for the Finance and Regulatory Affairs department, in both nominal and inflation-adjusted (real) dollars are shown in the table below.[122] The Finance and Regulatory Affairs department O&M has increased over the PBR Period, however, on an inflation-adjusted (real) basis, O&M per customer basis has stayed flat.

[121] See Appendix F-2 for a copy of Headcount History and Demographic Data
[122] See Appendix F-4 for a copy of Inflation History and Outlook

Table B-1-22: Finance and Regulatory Affairs department O&M over the PBR Period

	Decision 2003	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Projection 2009
Finance & Regulatory Affairs Nominal O&M ($ millions)	$ 8.6	$ 6.6	$ 7.4	$ 7.1	$ 7.8	$ 8.7	$ 9.6
Finance & Regulatory Affairs Real O&M ($ millions	$ 9.7	$ 7.3	$ 8.0	$ 7.5	$ 8.1	$ 8.9	$ 9.6
Real O&M per Customer	**$ 13**	**$ 9**	**$ 10**	**$ 9**	**$ 10**	**$ 11**	**$ 11**

The O&M of the Finance and Regulatory Affairs departments has remained relatively constant over the first four years of the PBR Period. Throughout the years 2005 through to 2007, the shortage of managers with a financial regulatory background resulted in lower overall O&M than required to fully support the required level of internal and external analysis and information. Beginning in 2008, additional resources were hired to support regulatory requirements resulting from changes to government energy policy and associated impacts, and the upcoming Regulatory filing calendar. The year 2009 reflects a full year of these additional resources, as well as formula-driven increases in BCUC quarterly assessment fees.

(vii) President and CEO

The O&M costs for the President and CEO department, in both nominal and inflation-adjusted (real) dollars are shown in the table below.[123] The President and CEO department O&M has decreased over the PBR Period. On an inflation-adjusted (real) basis, costs have declined significantly over the period, both in terms of total dollars and on a per customer basis.

Table B-1-23: President and CEO Department O&M over the PBR Period

	Decision 2003	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Projection 2009
President & CEO Nominal O&M ($ millions)	$ 21.4	$ 35.1	$ 18.9	$ 25.7	$ 21.1	$ 19.3	$ 17.5
President & CEO Real O&M ($ millions)	$ 24.1	$ 38.8	$ 20.5	$ 27.3	$ 21.9	$ 19.7	$ 17.5
Real O&M per Customer	$ 31	$ 50	$ 26	$ 34	$ 27	$ 24	$ 21

The majority of the President and CEO department budget includes corporate costs such as company insurance premiums, the Terasen management fee, industry association fees (i.e. Canadian Gas Association, Western Energy Institute) recoveries for Shared Services with TGVI and Non Regulated Businesses, and corporate adjustments. It also includes the President and CEO and Executive Assistant salary and support costs.

[123] See Appendix F-4 for a copy of Inflation History and Outlook

During the PBR Period, significant changes occurred primarily as a result of changes in the Shared Services allocation, post employment benefits and one time corporate adjustments which are recorded in the President and CEO's department. While Terasen management fees remained flat during the PBR Period, increases in Shared Services with TGVI contributed to an increase in recoveries. Reductions in other post employment benefits (OPEB) over the last several years also have contributed to the trend of lower spending. 2004 was significantly higher, highlighted by corporate restructuring costs of $9.6 million.

(c) Capital 2003 to 2009

Over the term of the PBR Period, approved capital expenditures other than CPCNs were determined by way of a formula based on the capital expenditures included in the 2003 decision. The incentives inherent in the PBR Agreement provided the Company the significant motivation to seek out opportunities for efficiency gains in its capital expenditures. This has meant that over the PBR Period there have been substantial capital expenditure savings that were shared with customers, which have helped to keep delivery rates down. This has also meant that the total capital expenditures projected for 2009 are well below the level included in the 2003 base year after adjusting for inflation, and capital expenditures per customer in 2009 is expected to be well below the 2003 base year level on both a real and a nominal dollar basis. The Company views this evidence of significant efficiency gains as a clear demonstration of our commitment to continuous improvement and Operational Excellence. Over the term of the PBR Period, Terasen Gas has effectively utilized resources and successfully minimized the capital expenditures required to provide safe, reliable, and efficient service to new and existing customers. The Company prudently managed the expansion of its assets and maintained the safety and integrity of the existing natural gas distribution system.

In this capital expenditure review section, the determination of the allowed capital expenditures will be described, followed by a review of the savings on an annual basis. A discussion of the efficiency gains over the period will then precede a discussion of the capital expenditures in more detail by category.

As part of the Annual Review process each year, the formula-based customer-addition driven capital (mains, services and meters) was determined based on prior year capital expenditures per customer, inflated for customer additions and an efficiency-adjusted inflation factor. The efficiency-adjusted factor was the same as that used in the O&M expense formula, being 1/2 of inflation for 2004 and 2005, and

2/3 for the fours subsequent years. The other base capital expenditures were based on the number of customers, and adjusted annually for the same efficiency-adjusted inflation factor. The calculation of the formula capital expenditures is displayed in Table B-1-24 below for each year of the PBR Period.

Table B-1-24: Calculation of Formula Capital expenditures over the PBR Period

Formula Customer Addition Capital Expenditures = (Prior Year Per Customer $) x (1+CPI - Adjustment Factor) x Forecast Customer Addition
Formula Other Base Capital Expenditures = (Prior Year Per Customer $) x (1+CPI - Adjustment Factor) x Forecast Average Customers
Formula Capital Expenditures = Formula Customer Addition CapEx + Formula Other Base CapEx

($ thousands)	Approved 2003	Approved 2004	Approved 2005	Approved 2006	Approved 2007	Approved 2008	Approved 2009
Previous Year Customer Addition Driven Capital Expenditure Per Customer ($)		2,093.04	2,110.83	2,131.94	2,147.89	2,162.50	2,177.21
Previous Year Other Base Capital Expenditure Per Customer ($)		85.69	86.42	87.28	87.93	88.53	89.13
CPI		1.70%	2.00%	2.20%	2.00%	2.00%	2.10%
Adjustment Factor		-0.85%	-1.00%	-1.45%	-1.32%	-1.32%	-1.39%
Net Inflation Factor		100.85%	101.00%	100.75%	100.68%	100.68%	100.71%
Formula Customer Addition Driven Capital Expenditure Per Customer ($)	2,093.04	2,110.83	2,131.94	2,147.89	2,162.50	2,177.21	2,192.76
Formula Other Base Capital Expenditure Per Customer ($)	85.69	86.42	87.28	87.93	88.53	89.13	89.77
Forecast Customer Additions		8,604	10,144	12,692	13,385	11,797	6,949
Forecast Average Number of Customers		777,779	790,385	804,316	820,347	829,970	834,283
Customer Addition Driven Capital Expenditures		18,162	21,626	27,261	28,945	25,685	15,237
Other Base Capital Expenditures		67,216	68,985	70,724	72,625	73,975	74,894
Total Formula Capital Expenditures		85,377	90,611	97,985	101,570	99,660	90,131

Source: Terasen Gas Inc. 2008 Annual Review of 2009 Revenue Requirements and Rates Section A Tab 3 Page 4

It is anticipated by the end of the six-year PBR Period, that as a result of the Company's prudent management, the cumulative capital expenditure savings available for sharing in accordance with the capital Incentive Mechanism will be $84 million. The table below summarizes the Company's capital expenditures from 2004 to 2009 by customer driven and base capital expenditures, with a comparison to the formula-based targets over the same time period.

Table B-1-25: Prudent Management Has Resulted In Capital Savings Over the Period of $84 million[124]

	Actual					Projection
	2004	2005	2006	2007	2008	2009
Formula Base Capital Expenditure Spending as Approved						
Customer Addition Driven CapEx	$ 18.2	$ 21.6	$ 27.3	$ 28.9	$ 25.7	$ 15.2
Other Base Capital CapEx	67.2	69.0	70.7	72.6	74.0	74.9
Total Base Capital Expenditures - Formula	$ 85.4	$ 90.6	$ 98.0	$ 101.6	$ 99.7	$ 90.1
Actual Base Capital Expenditures						
Customer Addition Driven CapEx	$ 21.9	$ 25.2	$ 28.8	$ 28.9	$ 32.3	$ 25.4
Other Base Capital CapEx	48.5	50.5	54.8	44.3	57.7	63.4
Total Base Capital Expenditures - Actual	$ 70.4	$ 75.7	$ 83.6	$ 73.2	$ 90.0	$ 88.8
Capital Savings Available for Sharing	$ 15.0	$ 14.9	$ 14.4	$ 28.4	$ 9.7	$ 1.3
Cumulative Capital Savings Available for Sharing	$ 15.0	$ 29.9	$ 44.3	$ 72.7	$ 82.4	$ 83.7

Amounts in $ millions

Comparing the actual capital expenditures by year to the formula capital expenditures demonstrates the savings that have been included in the calculation of earnings sharing both through reduced rate base, and through reduced depreciation expense through the term of the PBR Period. The resulting savings from these reduced capital expenditures have been shared equally between the shareholder and the customers. This illustrates the benefits that can be achieved by aligning the capital and O&M incentive mechanisms over a longer-term period.

The PBR plan also includes a process for an end-of-term capital incentive mechanism that carries beyond the end of the PBR Period. The accumulated capital benefit at the end of the term of the PBR Period will be phased out by factors of 2/3 in the first year after plan expiry and 1/3 in the second year after. The capital-related incentive is based on the cumulative difference between the formula-based customer expenditures calculated using the actual customer counts, and the actual capital expenditures. As shown in Part III, Section C, Tab 13 Schedule 71 End of Term Capital Incentive Mechanism, the total cumulative difference between the formula and actual customer expenditures at the end of 2009 is projected to be $72.3 million. The capital incentive is 14 per cent of this amount or $10.1 million, of which $5.1 million is the Company's portion. The Company will retain 2/3 of this benefit or $3.4 million in 2010 and 1/3 or $1.7 million in 2011. See Part III Section C, Tab 2, Revenue Requirements for a discussion of how this end of term benefit will be recovered from customers.

As stated above, the formula driven allowed capital expenditures for the PBR Period were based on the approved expenditures for 2003. As such the 2003 base level of capital expenditures both in total and on a per customer basis forms the logical basis for the comparison of the efficiency gains realized in the Company's actual capital expenditures over the PBR Period. The following table compares annual gross

[124] See Appendix I-1 Rate Base History, Page 5 for a summary of actual base capital expenditures

capital expenditures by category of expenditure (which are described later in this section) starting with the 2003 base year, followed by actuals for 2004 through 2009. This has been done in nominal dollars as well as on an inflation-adjusted (real $2009) basis.

Table B-1-26: 2009 Total Capital Expenditures [125] are Lower Than 2003 Base

	2003 Decision	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2004 - 2009 Average
Category A								
Mains	6.0	5.3	7.4	8.1	8.1	11.0	8.9	8.1
Services	10.6	13.3	14.6	16.4	17.1	18.0	15.0	15.7
New Meters & Meters Recalled	16.9	15.4	15.3	16.2	13.7	14.9	14.0	14.9
Total Category A Nominal	**33.5**	**34.0**	**37.3**	**40.7**	**38.9**	**43.9**	**37.9**	**38.8**
Total Category A Real	**37.7**	**37.7**	**40.5**	**43.3**	**40.5**	**44.8**	**37.9**	**40.8**
Category B								
Transmission Plant	8.2	7.1	5.6	8.7	5.1	13.3	11.3	8.5
Distribution Plant	17.2	11.0	10.2	9.7	10.4	8.1	8.7	9.7
Total Category B Nominal	**25.4**	**18.1**	**15.8**	**18.4**	**15.4**	**21.4**	**20.0**	**18.2**
Total Category B Real	**28.6**	**20.0**	**17.1**	**19.5**	**16.1**	**21.9**	**20.0**	**19.1**
Category C								
IT	14.9	7.3	10.6	7.8	4.2	10.5	16.0	9.4
Non-IT	12.1	10.9	12.0	16.6	14.7	14.2	14.9	13.9
Total Category C Nominal	**27.0**	**18.3**	**22.6**	**24.5**	**18.8**	**24.7**	**30.9**	**23.3**
Total Category C Real	**30.4**	**20.2**	**24.5**	**26.0**	**19.6**	**25.2**	**30.9**	**24.4**
Total Nominal	**85.8**	**70.4**	**75.7**	**83.6**	**73.2**	**90.0**	**88.8**	**80.3**
Total Real	**96.7**	**77.9**	**82.1**	**88.8**	**76.2**	**91.9**	**88.8**	**84.3**
Figures exclude AFUDC and Capitalized Overheads								
Average Customers	770,368	779,498	791,647	803,686	817,480	825,957	833,798	808,678
Total Nominal $/Customer	**111**	**90**	**96**	**104**	**89**	**109**	**106**	**99**
Total Real $/Customer	**125**	**100**	**104**	**110**	**93**	**111**	**106**	**104**

Note: Expenditures in $millions; Real totals in 2009 values

Total 2009 capital expenditures, excluding CPCN related expenditures, of $88.8 million are significantly lower than the 2003 Decision based in real dollars ($96.7 million). Additionally, the average capital expenditures over the PBR Period, both in nominal and real dollars are lower than the 2003 Decision. This result is despite the labour inflation (approximately 3 per cent) being a full percentage point higher than the average CPI used during the Annual review process to adjust to the Real capital expenditures. When compared on a per customer basis over the period, total capital expenditures in 2009 are lower in nominal and real dollars as compared to the 2003 Decision. Following is a discussion of the three Categories of capital expenditures with explanations provided for the changes observed, providing support that past expenditures have been reasonable and prudently managed.

[125] Excludes CPCNs

(i) Category A - Customer Driven Capital – Mains, Services and Meters

Category A capital expenditures includes the installation of new mains, services and meters. These expenditures are necessary to attach new customers to the gas distribution system. In addition, this Category also includes expenditures for gas meters utilized for meter exchange activities to serve the existing customer base.

Table B-1-27: Customer Driven Capital for the PBR Period

	2003 Decision	2004 Actuals	2005 Actuals	2006 Actuals	2007 Actuals	2008 Actuals	2009 Projection	2004 - 2009 Average
Mains	6.0	5.3	7.4	8.1	8.1	11.0	8.9	8.1
Services	10.6	13.3	14.6	16.4	17.1	18.0	15.0	15.7
New Meters & Meters Recalled	16.9	15.4	15.3	16.2	13.7	14.9	14.0	14.9
Total Nominal	**33.5**	**34.0**	**37.3**	**40.7**	**38.9**	**43.9**	**37.9**	**38.8**
Total Real	**37.7**	**37.7**	**40.5**	**43.3**	**40.5**	**44.8**	**37.9**	**40.8**
Average Customers	770,368	779,498	791,647	803,686	817,480	825,957	833,798	808,678
Total Nominal $/Customer	**43.4**	**43.7**	**47.1**	**50.7**	**47.5**	**53.1**	**45.5**	**47.9**
Total Real $/Customer	**48.9**	**48.3**	**51.2**	**53.8**	**49.5**	**54.2**	**45.5**	**50.4**

Note: Expenditures in $millions; Real totals in 2009 values

(a) Mains

Mains expenditures are incurred for installation of distribution main extensions to serve new customers. The two primary factors affecting Main expenditure levels are the level of activity (metres of pipe installed) and unit cost to install the main (dollars per metre). Prior to installation, all proposed main extensions are assessed using the MX Test, which is discussed in Part III, Section C, Tab 9. Contributions may be required from customers if forecast usage and revenues are insufficient to offset estimated installation and operating costs. New mains expenditures and unit costs discussed below do not include offsetting customer contributions in aid of construction (“CIAC”).

Service header mains which are also assessed through the economic test and are essentially distribution mains installed on private property (i.e. strata complexes), are excluded from new Mains expenditures and included in the Services section below. Historical new mains activity, together with unit costs and capital expenditure levels are summarized in Table B-1-28 below.

Table B-1-28: Mains Activity Levels and Costs for the PBR Period

	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Projection
Activities (metres)	121,570	156,604	174,003	164,550	157,004	200,167	115,305
Workforce:							
Terasen (%)	57%	41%	36%	26%	14%	13%	70%
Contractors (%)	43%	59%	64%	74%	86%	87%	30%
Unit Costs:							
Terasen ($/m)	38	34	44	35	66	66	86
Contractor ($/m)	30	33	38	51	48	52	55
Combined ($/m)	34	33	40	47	51	54	77
CIACs ($/m)	n/a	0	(4)	(2)	(1)	(1)	(1)
Net Combined ($/m)	34	33	36	45	50	53	76
Expenditures ($millions)							
Mains (excluding CIACs)	$4.2	$5.3	$7.4	$8.1	$8.1	$11.0	$8.9

(i) Mains Activity Levels

New mains activity levels, affected by the number of customer additions to Terasen Gas' system, rose 65 per cent from 121,570 metres in 2003 to 200,167 metres in 2008, with most of the growth in the Interior where activity levels rose 192 per cent from 38,957 metres (2003) to 111,270 metres (2008). A regional breakdown of the Interior mains activity levels for 2003 and 2008 is provided in Appendix E-1: Category A Capital Historical Information. Interior mains activities comprised 37 per cent of total mains activity in 2003 and in 2008 represented 55 per cent of activities. Over the same period, in the Lower Mainland, activity levels ranged between 78,000 and 103,000 metres annually with the peak in 2005. 2008 activity level was 90,464 metres, up 10 per cent from the 2003 level of 82,612 metres.

(ii) Mains Unit Costs

New mains unit costs, the second factor affecting the level of expenditure for new mains, is influenced by system design, length, pipe size, and material as well as location, installation conditions and workforce attributes. Included in new mains unit costs are expenditures for planning, design, surveying, staking, field installation, contractors (flagging, paving, etc), equipment and vehicles, government fees, material (pipe, fittings, backfill, etc) and drafting. Each new main job is unique which results in a wide range of unit costs. Unit costs, all other things being equal, rise over time in parallel to labour and contractor inflation. Approximately 80 per cent of the new mains cost is the field installation with the remainder attributable to materials, planning, and drafting.

From 2003 to 2008, new mains unit costs increased from $34/metre to $55/ metre or 62 per cent. A number of factors contributed to the pressures experienced. Challenges faced by Terasen Gas in containing new mains costs include managing multiple installation contractors, managing the demographic challenge in the internal field workforce (recruiting, training and outfitting apprentices to replace retiring workers), managing construction with a multitude of municipalities, increasing customer and general public expectations for enhanced levels of service and safety, and inflationary increases in wages, vehicles, contracts and materials.

Contractor new mains unit costs have remained relatively flat since 2006 with contracts being extended with consumer price index inflators. Terasen Gas' use of multiple contractors enables it to successfully meet peak demands in a variety of geographical locations, diversify contractor risk and keep contractor pricing competitive in what has been a robust provincial economy.

Terasen Gas internal field workforce new mains unit costs have risen primarily due to changes in crew size and the additional work in various interior locations. Terasen Gas' internal field workforce installs new mains infrequently as they are primarily first responders to emergency situations. As a result, Terasen Gas new mains unit costs are generally higher. Terasen Gas' internal field workforce level/model is set to core/emergency footprint requirements similar to fire departments so that adequate levels of resources are able to respond appropriately to emergencies as well as core operations, maintenance and customer service work with mains and service work as options available to minimize first response standby and idle time.

In 2007, in response to increasing retirements and demographic challenges within our core/emergency internal workforce footprint, Terasen Gas increased its typical Lower Mainland install crew configuration from 3 to 4 by adding an apprentice. For Terasen Gas installed mains, this training/succession planning initiative has put pressure on the unit costs and will continue to do so. In 2008, a similar program was initiated in the Interior. The apprentices are attached to the crews allowing them to learn alongside the seasoned veterans. Terasen Gas expects this program to continue into 2010 and 2011 as eligible retirements currently exceed one hundred and twenty-five or roughly one third of the field workforce. As senior field employees retire, apprentices will move up the crew seniority chain. With field employee retirements in the 20-40 range annually, this program is expected to be in place for the next five years depending on economic conditions.

New mains unit costs have also been negatively impacted by inflationary increases in paving rates, paving requirements by municipalities and material costs. Paving rates due to the impact of oil prices which peaked at over US$145 per barrel and material costs (gravel, sand, fill, etc) have risen due to demand and supply within local municipalities. More onerous paving requirements by municipal authorities have increased the amount of replacement paving required during new main installations.

Other factors which negatively impacted overall unit costs during this period are location, pipe size and material. The growth in new mains activities in the Interior, which is served by one install contractor and a variety of regional offices, has contributed to the higher trend in unit costs. Travel times and contractor mobilization costs are factored into Interior unit costs. Lower Mainland West unit costs are significantly higher than Fraser Valley unit costs due to the amount of pavement versus green-field development, traffic control requirements, etc.

New mains pipe sizing (7 dimensions ranging from 26 mm to 219 mm), driven by design and future demand, have shifted to larger sizes which are generally more expensive to install. Coiled polyethylene (PE) pipe is more easily rolled out for smaller dimension pipe while labour intensive fusion techniques are required to join “sticks” of the larger dimension pipe. From 2003 to 2008, the percentage of larger dimension pipe (88-219 mm) increased from 13 to 17 per cent. Over the same period there has also been a shift to higher pipe sizing within the lower pipe dimension ranges (26-60mm) partly in an effort to standardize pipe dimensions. In 2003, 42 mm pipe represented 33 per cent of new mains installed. In 2008, 42 mm pipe represented only 27 per cent with a corresponding higher amount of larger 60 mm pipe used.

(b) Services

Service expenditures in Category A consist of a variety of Services types offered to serve new customers. These include new and conversion DP and Intermediate Pressure (“IP”) services to single and multi-family dwellings, gas stub service from the main, services installed from the stub, vertical header subdivisions (a vertical service line system within a building such as a high-rise) and DP and IP new or conversion service header mains and DP and IP service header laterals. Service header mains are distribution mains installed on private property (i.e. multi-family strata owned complexes). There are two basic considerations in understanding the Service expenditures level. Similar to new mains, they are the level of activity (number of services installed, number of service header main installed) and aggregate unit cost to install the service (dollars per service) and/or service header main (dollars per metre).

Prior to installation, all proposed service costs are estimated. If the estimated cost exceeds the Service Line Cost Allowance a contribution may be required from the customer. Service expenditures and unit costs discussed below do not include offsetting CIACs. Included in the Services CIACs from 2003 to 2007 was a $215 per service per customer charge which was discontinued in 2008 under Commission Order No.G-152-07 issued Dec 6, 2007.

Historical Services and Service Header Mains activities, together with unit costs and capital expenditure levels are summarized in Table B-1-29 below. In addition, shown is the historical CIAC offset to Services expenditures as well as the lowering effect contributions have on aggregate services unit costs.

Table B-1-29: TGI Services / Service Header Mains 2003 - 2009

	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Projection
Net Customer Additions	5,546	11,504	12,420	10,101	9,939	9,256	6,120
Gross Customer Additions	12,837	15,549	12,770	13,338	15,533	14,566	9,600
Ratio of Service Additions to Gross Customer Additions	0.83	0.85	0.97	0.93	0.70	0.72	0.78
Activities:							
Service (risers)	10,697	13,201	12,401	12,525	10,935	10,520	7,510
Service Header Mains (metres)	29,082	49,275	48,480	57,360	41,937	48,041	34,589
Workforce:							
Services - Terasen (%)	81	68	59	51	57	62	90
Services - Contractors (%)	19	32	41	49	43	38	10
Service Headers Main - Terasen (%)	77	45	37	26	18	21	60
Service Headers Main - Contractor (%)	23	55	63	74	82	79	40
Unit Costs:							
Services	818	842	944	1,057	1,318	1,410	1,650
Service Header Main	51	45	59	55	64	67	76
All Services $/Service	958	1,008	1,175	1,310	1,562	1,709	2,000
CIAC $/Service	-309	-321	-349	-367	-387	-428	-412
*Net Combined Unit Cost $/Service	658	687	826	942	1,174	1,281	1,588
Expenditures ($millions)							
Services	8.7	11.1	11.7	13.3	14.4	14.8	12.4
Services and Vertical Header Mains	1.5	2.2	2.9	3.1	2.7	3.2	2.6
Total (Pre-CIACs)	10.2	13.3	14.6	16.4	17.1	18.0	15.0
CIACs Services	(3.3)	(4.2)	(4.3)	(4.6)	(4.2)	(4.5)	(3.1)
Total (After CIACs)	10.2	13.3	11.9	11.8	12.9	13.5	11.9

(i) Services Activity Levels

Annual Service additions, affected by the number of customer additions to Terasen Gas' system, rose from 10,067 in 2003 to 13,201 or 31 per cent growth in 2004 and have gradually fallen back to 10,520 in 2008. Service header mains, included in Services expenditures, rose from 29,082 metres in 2003, peaked in 2006 at 57,360 metres (97 per cent growth) and fell back to 48,041 metres in 2008 (65 per cent higher than 2003).

The mix of service additions geographically has changed from 2003 to 2008 in the various service product categories. The substantial service header mains activity growth has been in the Interior (Thompson/Okanagan) as well as in the Lower Mainland. A 2003 versus 2008 regional breakdown of the service header mains activity levels is provided in Appendix E-1.

(ii) Services Unit Costs

Aggregate service unit cost which is the second consideration in expenditures for new services is calculated by taking all services costs and dividing by the number of risers (services) installed. The aggregate services unit cost includes new and conversion services to single and multi-family dwellings, service header mains (main on private property - generally associated with strata complexes), and vertical subdivisions (high-rises). Services can be short-sided (attached to main on the same side of the street as the customer premise) or long-sided (attached to main on the opposite side of the street as the customer premise).

Like new mains, service costs are influenced by design, length, pipe size, and material as well as location, installation conditions and workforce attributes. Included in new service and service header main costs are expenditures for planning, field installation, contractors (flagging, paving, etc), equipment and vehicles, government fees, material (pipe, fittings, backfill, etc) and drafting.

Each type of service is distinct resulting in a wide range of unit costs between service products (i.e. new service to a single family home versus new service to a vertical /high-rise subdivision). Within each service product category there is some differentiation (i.e. long side service versus short side service). Approximately 80 per cent of the services unit cost is the field installation with the remainder attributable to material and other costs. Aggregate unit costs, all other things being equal, rise over time in parallel to labour and contractor inflation. Separate unit costs are calculated for services (risers) and service header mains (metres) albeit all these costs are included in an aggregate or combined services unit cost.

From 2003 to 2008, the adjusted ("Net Combined") aggregate Services unit costs (refer to Table B-1-28 above after considering CIACs received) increased from $658 per service to $1,281 per service or 95 per cent. From 2003 to 2008, the aggregate services unit cost without consideration of the CIAC, increased from $958/service to $1,709/ service or 78 per cent. There are several factors which have contributed to the pressures experienced with aggregate services unit costs during the PBR Period. Challenges faced by Terasen Gas in containing services costs are similar to those for new mains including managing multiple installation contractors, managing the demographic challenge in the internal field workforce (recruiting, training and outfitting apprentices to replace retiring workers), and inflationary increases in wages, vehicles, contracts and materials. Refer to previous section Mains Unit Cost for discussion.

(c) Meters – New and Replacement

Meter expenditures in Category A are those associated with meters (and regulators) required to serve new customers as well as to purchase gas meters utilized for meter and regulator exchange activities for the existing customer base. These include residential, commercial and industrial meters (and regulators) purchased from suppliers as well as meters fabricated in Terasen Gas facilities to accommodate specific customer requirements.

Meter exchange is the activity of removing in-service gas meters and replacing them with new or repaired meters to maintain accurate measurement, as required by the *Electricity and Gas Inspection Act of Canada.* The purchase, removal and re-installation of new meters are a capital expenditure. Where the meter is part of a sampling program and returned to service, the exchange is considered an operating expense. Residential and some small commercial meter exchanges require a brief interruption of gas service to a customer's premise, and the relighting of gas appliances by a Terasen customer service technician or qualified contractor once the meter exchange has been completed. Meter exchange work activities (residential, commercial and industrial) are completed by Terasen Gas' internal work force.

There are two main considerations in understanding the meter expenditure level. They are the level of activity (meters purchased and installed or exchanged) and the unit cost to purchase, fabricate and install the meter (dollars per meter). A summary of historical and forecast new and replacement meter activities, unit costs, and expenditures follow in Table B-1-30, below. The level of activities, both meters required for new customers and those required for exchange for existing customers, taken together with an average unit cost provide the basis for the expenditures.

Table B-1-30: Meters – New and Replacement – Activities, Unit Cost, Expenditures

	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Projection
Activities							
Meters - New	5,655	11,534	12,474	10,188	9,939	9,256	6,120
Meters - Exchange	45,142	42,638	46,920	28,446	30,417	33,275	46,700
Meters - Total	50,797	54,172	59,394	38,634	40,356	42,531	52,820
Unit Costs ($/meter)							
Meters	342	285	258	419	336	335	265
Expenditures ($millions)							
Meters - New	1.9	3.3	3.2	4.3	3.3	3.1	1.5
Meters - Exchange/Other	15.4	12.1	12.1	11.9	10.3	11.8	12.5
Meters - Total	17.4	15.4	15.3	16.2	13.6	14.9	14.0

The level of meter exchange activity is driven by life expectancy of meters and the total size of the meter population. There are two key drivers that have significantly influenced the meter recall schedule for Terasen Gas which are outlined below.

Prior to 2006, Terasen Gas managed the residential meter fleet to a 28 year life span enabled by one maintenance and recondition operation at the midpoint of this 28 year life. This resulted in a meter recall frequency of 14 years. Communications with vendors, ongoing discussions within the Canadian Gas Association Measurement Committee and the company's own internal analysis, provided Terasen Gas the confidence to target a 20 year life span for the residential meter fleet without a mid-life recondition operation. This allowed Terasen Gas to temporarily reduce the number of meter recalls over the period 2006 - 2008 to bring the demographics of the meter fleet in line with a 20 year life expectancy which provided both customers and shareholders the cost benefits of previous investment in the fleet.

The adoption of a residential meter exchange frequency based on a 20 year life expectancy creates good alignment for the inevitable adoption of Automatic Meter Reading ("AMR"). AMR technology involves equipping a gas meter with a radio transmitter to broadcast meter readings to a collection device. AMR transmitters have a battery life of approximately 20 years so it is advantageous to harmonize meter recall frequency to this life expectancy.

(i) Meters Unit Costs

Meter unit cost is influenced by the type, size, and design of the meter, installation, fabrication and exchange conditions and the timing of bulk meter purchases. A blended unit cost of all customer types is used for meter exchanges and installs with meter unit costs ranging from $75 to $100,000 depending on the customer requirements. Meter costs include the purchase or remanufacture of residential, commercial and industrial meters and regulators; the testing and handling of new and remanufactured meters and regulators; prefabrication of meter set assemblies; installation of new meter sets and regulators; meter set renewals and upgrades and the purchase of demand metering devices; and electronic volume correction equipment.

2009 forecast unit costs are $265 per meter, a reduction from 2008 actuals of $335 per meter. The projected reduction is due to an increase in the proportion of residential meter exchanges from 2008 to 2009 and drop in the number of new customer meters.

(d) Category A Summary

As discussed, Category A expenditures for the period 2003-2009 have fluctuated up and down, driven by changes in unit costs and changes in activity levels influenced by the number of customer additions. During the same period, the number of meter exchanges has increased as it is no longer viable to maintain the lower exchange levels as the result of an aging meter fleet and anticipated early failures for some batches of meters purchased in the 1990s.

Terasen Gas has successfully mitigated some of the unit cost pressures and workforce succession planning issues through the use of a long term five year labour contract for its field workforce; regular tendering and extensions of install contracts; and enhancements to the job estimating process which ensures customers contribute for services where the estimates exceed allowed amounts for normal installation cost. While managing cost pressures, Terasen Gas has improved service levels for installation of services. In 2003, service installation commitment dates (appointments made with customers for service installations) were met 80 per cent of the time. In 2008, due to process changes, information technology enhancements and use of a contractor workforce, the comparative result has improved to 93 per cent.

(ii) Category B - Transmission and Distribution Systems Integrity and Reliability

The capital expenditures within Category B include gas system improvements to add capacity to the distribution and transmission system to meet customer growth and expenditures related to safety and reliability. Projects of a special nature, generally those with project budgets greater than $5 million, have typically been reviewed by the Commission through a separate CPCN process.

The key drivers for Category B expenditures are safety, reliability and growth. Capital additions to the transmission and distribution plant are required to maintain a high degree of system availability and to protect the public, landowners, customers and employees through assurance of pipeline and facility integrity. Those additions have to be completed in a cost-effective manner while recognizing the pressures associated with aging of the transmission and distribution infrastructure, increasing urbanization around rights-of-way and facilities, and increasing expectations by the public and government with regard to public safety, particularly after several publicized pipeline failures. The other key driver is customer additions that will inevitably require system expansion and reinforcement to meet peak day demands. Part of the Category B expenditures is for facilities required to meet customer growth and maintain reliability of the system.

(a) Historic Category B Expenditures 2003-2009

The Category B capital expenditures from 2003 through 2008 including 2009 projection are set out in the following table.

Table B-1-31: Savings have Been Realized in Category B Spending Throughout PBR Period

	2003 Decision	2004 Actuals	2005 Actuals	2006 Actuals	2007 Actuals	2008 Actuals	2009 Projection	2004 - 2009 Average
Transmission Plant	8.2	7.1	5.6	8.7	5.1	13.3	11.3	8.5
Distribution Plant	17.2	11.0	10.2	9.7	10.4	8.1	8.7	9.7
Total Nominal	**25.4**	**18.1**	**15.8**	**18.4**	**15.4**	**21.4**	**20.0**	**18.2**
Total Real	**28.6**	**20.0**	**17.1**	**19.5**	**16.1**	**21.9**	**20.0**	**19.1**
Average Customers	770,368	779,498	791,647	803,686	817,480	825,957	833,798	808,678
Total Nominal $/Customer	**33.0**	**23.2**	**19.9**	**22.9**	**18.9**	**26.0**	**24.0**	**22.5**
Total Real $/Customer	**37.1**	**25.7**	**21.6**	**24.3**	**19.7**	**26.5**	**24.0**	**23.6**

Note: Expenditures in $millions; Real totals in 2009 values

From 2003 to 2009, Category B capital expenditure requirements related to the replacement of aging infrastructure, updating facilities to meet changes to applicable codes and lesser amounts associated with capacity additions to meet customer growth.

(b) Category B Distribution Capital Expenditures

Investments in Category B Capital are required for the distribution system to maintain a high degree of system availability while protecting the public, customers and employees. Category B type of expenditures mitigate the risk of loss from system outages and business interruptions. Safety, reliability and growth expenditures are becoming increasingly important as insurance deductibles have escalated substantially for system outages and business interruption.

Distribution Category B capital expenditures for risk mitigation include upgrades to the gas distribution system to meet seismic standards, enhancements to the system in land slippage areas, and expenditures to ensure environmental protection of water courses. Capital expenditure requirements for the latter two activities peaked in 2006.

The table below provides the historic actual and forecast of Distribution Category B by type of work from 2003 through 2009.

Table B-1-32: Savings have Been Realized in Distribution Category B Spending

	2003 Decision	2004 Actuals	2005 Actuals	2006 Actuals	2007 Actuals	2008 Actuals	2009 Projection	2004 - 2009 Average
Plant System Improvements	13.9	6.8	7.3	6.1	9.2	7.2	8.7	7.5
Secondary Containment	1.3	1.8	2.5	3.5	1.1	0.8	-	1.6
Seismic Mitigation	2.0	2.5	0.4	0.1	0.0	0.1	-	0.5
Total Nominal	**17.2**	**11.0**	**10.2**	**9.7**	**10.4**	**8.1**	**8.7**	**9.7**
Total Real	**19.4**	**12.2**	**11.1**	**10.3**	**10.8**	**8.3**	**8.7**	**10.2**
Average Customers	770,368	779,498	791,647	803,686	817,480	825,957	833,798	808,678
Total Nominal $/Customer	**22.4**	**14.1**	**12.9**	**12.1**	**12.7**	**9.9**	**10.4**	**12.0**
Total Real $/Customer	**25.2**	**15.6**	**14.0**	**12.8**	**13.2**	**10.1**	**10.4**	**12.7**

Note: Expenditures in $millions; Real totals in 2009 values

The Distribution related Category B expenditures are primarily one time projects which vary in size, complexity and duration. These types of expenditures are driven mainly by the need to update and replace facilities to meet changes in code and to enable Terasen Gas to meet its customer requirements. The Distribution related Category B expenditures for the past five years were approximately $9.9 million per year, which included various one-time secondary containment mitigation projects as well as smaller system integrity/seismic mitigation projects. The projected spend in 2009 is $8.7 million, the bulk of which are system improvement and station upgrade projects.

(c) Category B - Transmission Capital Expenditures

The Transmission-related capital expenditures within Category B include system capacity improvements to meet core customer growth, and expenditures related to ensuring safety and reliability of the transmission system, as well as to minimize impact to the environment. Included in the transmission-related Category B expenditures are upgrades to components of compressor stations and transmission pipelines, SCADA and cathodic protection. Most of the upgrades such as compressor control replacements, pipeline valve replacements, SCADA equipment replacements, anode bed and rectifier replacements are due to equipment obsolescence of aging assets, excessive operating and maintenance costs, and component failure due to age.

The table below provides the historic actual and forecast of Transmission Category B by type of work from 2003 through 2009.

Table B-1-33: Savings have been Realized in Transmission Category B Spending

	2003 Decision	2004 Actuals	2005 Actuals	2006 Actuals	2007 Actuals	2008 Actuals	2009 Projection	2004 - 2009 Average
Pipeline	5.2	4.3	2.2	4.2	3.1	8.2	6.9	4.8
Compression	1.2	0.3	0.5	0.0	0.4	1.8	1.6	0.8
LNG	0.7	0.5	0.5	0.4	1.5	2.6	0.2	1.0
Miscellaneous	1.1	2.0	2.3	4.1	0.1	0.7	2.6	2.0
Total Nominal	**8.2**	**7.1**	**5.6**	**8.7**	**5.1**	**13.3**	**11.3**	**8.5**
Total Real	**9.2**	**7.8**	**6.0**	**9.2**	**5.3**	**13.6**	**11.3**	**8.9**
Average Customers	770,368	779,498	791,647	803,686	817,480	825,957	833,798	808,678
Total Nominal $/Customer	**10.6**	**9.1**	**7.0**	**10.8**	**6.2**	**16.1**	**13.6**	**10.5**
Total Real $/Customer	**12.0**	**10.1**	**7.6**	**11.5**	**6.5**	**16.5**	**13.6**	**10.9**

Note: Expenditures in $million; Real totals in 2009 values

A driver of Category B capital expenditures is the urbanization and road infrastructure activities and the resulting increased activities around transmission rights of way. Activities on private properties and realignment of highways adjacent to pipeline rights of way often necessitate the relocations of transmission pipelines and the associated rights of way. Also, the increased number of road crossings over the pipelines often necessitates upgrades in order to manage the additional stresses on the pipelines.

Most of the Category B projects cover a range of projects with values less than $1 million each, with some exceptions where mentioned. Historically, the expenditures in this category have averaged approximately $8.9 million per year from 2003 to 2009.

(d) Category C - All Other Plant

Capital expenditures for all other plant are included in Category C and split between IT and "Non-IT". Non-IT expenditures include costs required for the alteration and replacement of gas mains, gas services, and pressure regulator stations; the acquisition or leasing of land; facilities including station buildings, facilities equipment; telecommunications infrastructure; specialized tools and equipment; and radio system upgrades. IT expenditures include costs associated with information technology hardware, infrastructure, and software requirements.

Some expenditures within this category are somewhat sensitive to general economic cycles, particularly those required to support load growth driven by customer additions. However, the majority of non-IT Category C expenditures are more based on the overall size and age of the system and the need to ensure its safety and reliability. Other expenditures such as pipeline relocation work occur as the result of outside agencies such as municipalities, utilities, and developers. Technological obsolescence and improvements influence requirements for tools, equipment, radios and furniture. For IT projects, business needs and potential benefits arising from implementation of IT solutions are the primary determinants of IT capital expenditures.

The table below summarizes the historical annual Category C spending from 2003 to 2009; excluding CPCN expenditures.

Table B-1-34: Savings have Been Realized in Category C Spending

	2003 Decision	2004 Actuals	2005 Actuals	2006 Actuals	2007 Actuals	2008 Actuals	2009 Projection	2004 - 2009 Average
IT Projects	14.9	7.3	10.6	7.8	4.2	10.5	16.0	9.4
Non-IT Projects	12.1	10.9	12.0	16.6	14.7	14.2	14.9	13.9
Total Nominal	**27.0**	**18.3**	**22.6**	**24.5**	**18.8**	**24.7**	**30.9**	**23.3**
Total Real	**30.4**	**20.2**	**24.5**	**26.0**	**19.6**	**25.2**	**30.9**	**24.4**
Average Customers	770,368	779,498	791,647	803,686	817,480	825,957	833,798	808,678
Total Nominal $/Customer	**35.0**	**23.4**	**28.5**	**30.5**	**23.0**	**29.9**	**37.0**	**28.7**
Total Real $/Customer	**39.5**	**25.9**	**30.9**	**32.4**	**24.0**	**30.5**	**37.0**	**30.1**

Note: Expenditures in $millions; Real totals in 2009 values

The table below summarizes the Non-IT Category C historical expenditures for 2003 to 2009 on a per customer basis.

Table B-1-35: Non-IT Category C Spending

	2003 Decision	2004 Actuals	2005 Actuals	2006 Actuals	2007 Actuals	2008 Actuals	2009 Projection	2004 - 2009 Average
Main & Service Renewals/Alterations	5.2	6.5	8.1	11.0	7.0	7.0	5.0	7.5
Other Non-IT	6.9	4.4	3.8	5.6	7.6	7.2	9.9	6.4
Total Nominal	**12.1**	**10.9**	**12.0**	**16.6**	**14.7**	**14.2**	**14.9**	**13.9**
Total Real	**13.6**	**12.1**	**13.0**	**17.7**	**15.3**	**14.5**	**14.9**	**14.6**
Average Customers	770,368	779,498	791,647	803,686	817,480	825,957	833,798	808,678
Total Nominal $/Customer	**15.7**	**14.0**	**15.1**	**20.7**	**17.9**	**17.2**	**17.8**	**17.1**
Total Real $/Customer	**17.7**	**15.5**	**16.4**	**22.0**	**18.7**	**17.6**	**17.8**	**18.0**

Note: Expenditures in $millions; Real totals in 2009 values

(iii) Contribution in Aid of Construction

Contributions in Aid of Construction are recoveries from customers and third parties for direct costs and associated overhead for work performed at their request or for mitigating/restoring company property damaged by others. The recoveries are based on the following types of work:

- Contributory mains extensions initiated by developers;
- Service line costs exceeding the service line cost allowance ("SLCA");
- Gas service alterations and meter relocations initiated by existing customers;
- Pipeline and gas main alterations initiated by third parties such as road builders, municipalities, provincial government, and developers;
- Hazard mitigation work such as installation of protection posts or snow sheds chargeable to customers; and
- System damages such as hit lines.

The table below summarizes Terasen Gas' CIAC recoveries during 2003 – 2009.

Table B-1-36: CIAC History

	2003 Decision	2004 Actuals	2005 Actuals	2006 Actuals	2007 Actuals	2008 Actuals	2009 Projection	2004 - 2009 Average
Category A - Customer Additions	(3.8)	(4.2)	(4.3)	(5.1)	(4.6)	(4.9)	(3.2)	(4.4)
Category B - System Reliability & Integrity	(0.3)	(1.6)	(0.6)	(0.6)	(1.3)	(1.1)	(0.8)	(1.0)
Category C - IT and Non-IT	(4.0)	(1.7)	(3.2)	(4.0)	(2.4)	(4.7)	(2.6)	(3.1)
Category D - CPCN	-	-	-	-	0.0	(0.2)	-	(0.0)
Category F - Retirements	-	(0.0)	(0.2)	(0.1)	(0.3)	(0.4)	(0.2)	(0.2)
Total Nominal	**(8.1)**	**(7.6)**	**(8.3)**	**(9.8)**	**(8.5)**	**(11.3)**	**(6.7)**	**(8.7)**
Total Real	**(9.1)**	**(8.4)**	**(9.0)**	**(10.4)**	**(8.9)**	**(11.5)**	**(6.7)**	**(9.2)**
Average Customers	770,368	779,498	791,647	803,686	817,480	825,957	833,798	808,678
Total Nominal $/Customer	**(10.5)**	**(9.7)**	**(10.4)**	**(12.2)**	**(10.5)**	**(13.6)**	**(8.1)**	**(10.8)**
Total Real $/Customer	**(11.8)**	**(10.8)**	**(11.3)**	**(13.0)**	**(10.9)**	**(13.9)**	**(8.1)**	**(11.3)**

Note: Expenditures in $millions; Real totals in 2009 values

The average CIAC recovery during the 2004 – 2009 period is approximately $9 million with changes attributed to the above mentioned factors. A significant decrease in recoveries in 2009 is the result of the elimination of the service line installation fee approved by the Commission in Order No. G-152-07 dated December 6, 2007.

(iv) Allowance for Funds Used During Construction

Allowance for funds used during construction ("AFUDC") is a return on the company's invested capital or project financing costs for projects under construction that are not service. AFUDC is calculated on projects under construction where costs are greater than $50,000 and construction is anticipated to be three months or longer in duration. The AFUDC rate is based on the Company's weighted average cost of capital ("WACC") with the AFUDC calculated by multiplying the project expenditures by the Company's WACC.

The table below summarizes Terasen Gas' AFUDC for the years 2003 – 2009.

Table B-1-37: AFUDC for the PBR Period

	2003 Decision	2004 Actuals	2005 Actuals	2006 Actuals	2007 Actuals	2008 Actuals	2009 Projection	2004 - 2009 Average
Allowance for Funds Used During Construction	2.0	0.7	0.8	0.9	1.3	1.4	1.1	1.0
Total Nominal	**2.0**	**0.7**	**0.8**	**0.9**	**1.3**	**1.4**	**1.1**	**1.0**
Total Real	**2.3**	**0.7**	**0.8**	**0.9**	**1.4**	**1.4**	**1.1**	**1.1**

Note: Expenditures in $millions; Real totals in 2009 values

(d) Gross Margin and Other Revenues 2003 – 2009

Since 2003 our Company has experienced a decline in overall demand for natural gas, as previously discussed on page 109. This is a result of declining use per customer rates, which have been only partially offset by a growing customer base. Despite the decline in demand, the challenges in adding customers, and resulting decreases in use rates, Terasen Gas has been able to hold delivery rates relatively flat over the term of the PBR Period. In fact, the decline in use rates over the years 2004 to 2009 accounted for approximately 90 per cent of the total revenue deficiency over that same period, and contributed in large part to the delivery rate increases that were experienced.

Customer growth, demand, and use rates were re-forecast annually in the process of setting rates for the following year, as part of the annual review process. To the extent that Terasen Gas has been successful in forecasting customer additions, and the decline in use rates, these two factors together have not impacted the financial results of the Company. Under the PBR Agreement, financial risk in this area has been limited to variances between forecast and actual results, with these variances shared equally between customers and the shareholder. Over the PBR Period actual revenues (both gross margin and other revenues) were lower than the approved forecast amounts, therefore this resulted in a reduction in the amount of earnings available for sharing.[126] As can be seen from the following Table B-1-38, the negative contribution to the earnings sharing from the gross margin and the other revenues during the PBR Period was a total of $18.7 million.

[126] See Appendix F-5 for a copy of Earned Return History

Table B-1-38: Gross Margin and Other Revenues reduced Earnings Sharing otherwise Available

($ millions)

	Actual					Projection	
	2004	2005	2006	2007	2008	2009	Total
Gross Margin							
Actual/Forecast	473.4	478.5	492.7	486.2	491.3	502.9	2,925.0
Approved	475.5	477.9	494.7	488.7	491.0	501.4	2,929.1
Contribution to sharing (pre-tax)	(2.0)	0.6	(1.9)	(2.5)	0.3	1.5	(4.1)
Other Revenue							
Actual/Forecast	20.1	23.3	22.7	22.0	21.8	20.9	130.9
Approved	22.6	26.0	24.8	24.9	23.7	23.4	145.5
Contribution to sharing (pre-tax)	(2.5)	(2.7)	(2.1)	(2.9)	(1.9)	(2.5)	(14.6)
Total pre-tax contribution	(4.5)	(2.1)	(4.1)	(5.4)	(1.5)	(1.1)	(18.7)

(i) Gross Margin

Overall, the gross margin of the Company has shown a steady increase each year, as the annual revenue requirements have been calculated to reflect both growing rate base and cost of service including the impacts of both formula-based and other cost drivers that are re-forecasted annually.

Variances between the approved and actual gross margin are primarily a function of higher or lower customer additions than forecast, and for the non-core customer classes, changes in the annual demand for individual customer classes. The annual demand for non-core customers is heavily impacted by the economy and also industry-specific factors. An example of industry-specific factors would include the U.S. housing market, which is significantly impacting the B.C. forestry industry. The spot market for natural gas impacts consumption in the greenhouse sector, as our customers in that sector have fuel switching capabilities and are therefore able to respond to shorter-term fluctuations in the price of natural gas. Additionally, the conservation targets outlined in the B.C. Energy Plan are expected to impact the Education, Government Buildings, and also Commercial/Office Building sectors, as those sectors continue to improve efficiencies.

(ii) Other Revenue

Other revenue has been relatively flat throughout the PBR Period. In 2005 there was a significant increase in other revenue due to increased SCP revenues related to the replacement of the PG&E Energy Trading contract with the Northwest Natural contract. In 2009, other revenues are expected to decline from levels experienced in 2008. This is due to expected declines in both connection fee revenues and also late payment charges. Connection fee revenue is highly dependent on customer additions, which given the slowdown in the housing market are declining significantly from 2008 levels. Late payment charges are projected based on past experience, and expressed as a percentage of overall revenue, which is expected to decline from 2008 levels.

Variances between the approved and actual other revenues were almost entirely due to late payment charge revenues. For purposes of the PBR Agreement, late payment charges were calculated based on a formula, which on average has been $2.4 million higher than the actual level of late payment charge revenue received.

As stated above, for the PBR Period, gross margin and other revenue in aggregate resulted in a reduction to the earnings available for sharing. Fortunately, for customers and the Company the previously described O&M expense savings and the effect of the capital expenditures savings over the period more than offset this.

(e) Exogenous Factors

During the term of the PBR Period, the Company received special treatment for Exogenous Factors. Customers' rates were adjusted for those exogenous factors that were beyond the control of the Company including: judicial, legislative or administrative changes, orders and directions; catastrophic events, by-pass or other similar events imposed on Terasen Gas which were not reflected in the 2003 base upon which subsequent year's rates were set. Also included in Exogenous Factors were changes in Generally Accepted Accounting Principles, standards and policies. Changes in revenue requirements resulting from directions from the Commission were also to be treated as Exogenous Factors.

Terasen Gas applied for and received Exogenous Factor treatment during the years 2004 to 2009 for:

<u>Government Policy Changes and Legislative Changes</u>

- Ontario Securities Commission Compliance Costs
- PST Reassessment re Southern Crossing Pipeline
- Carbon Tax Implementation
- Olympic Security Costs
- Unforecasted annual changes to income tax rates

<u>Changes resulting from directions of the Commission</u>

- BCUC Levies

GAAP Changes

- Accounting Guideline AcG 15 Consolidation of Variable Interest Entities
- Inventories
- IFRS Implementation Costs

During the term of the PBR Period, the exogenous factor treatment existed to capture the material impacts of many of the same external cost drivers discussed in Part III, Section A, External Situational Context. As the PBR Period comes to an end, it is consistent and necessary that Terasen Gas reflect the impact of these same factors in the forecast of revenue requirements.

(f) Summary of Financial Results over the PBR Period

The incentive mechanisms that were included in the PBR Agreement created a framework that encouraged the Company to actively pursue and achieve efficiencies, for the benefit of customers and the Company, without sacrificing service quality. Terasen Gas accepted the challenge that the incentives presented and throughout the PBR Period strove to capture all of the efficiencies available, while at the same time maintaining its commitment to service quality. The efficiencies and cost savings achieved were significant and Terasen Gas believes it has realized all of the opportunities it had for substantive efficiency gains during the PBR Period, and as a result, customers and the shareholder have equally realized the benefits of these efficiencies. A chief result of these efficiency gains is that projected O&M expenses and capital expenditures for 2009, after consideration of inflation for the period, are lower than the levels included in the 2003 Decision, which formed the basis for the formulaic driven costs included in the PBR Agreement. Terasen Gas intends to continue to pursue efficiencies in its pursuit of continuous improvement and Operational Excellence now and into the future.

(6) TRUSTED AND RESPECTED OPERATOR PAST SUMMARY

During the 2004 through 2009 period Terasen Gas has demonstrated its commitment to providing our customers with safe, reliable, and cost effective service. The Company's pursuit of continuous improvement and its focus on Operational Excellence has allowed for the realization of significant efficiencies through our prudent management of O&M expenses and capital expenditures throughout the PBR Period. The Company has achieved significant accomplishments in its operations performance, which have helped to allow the realization of efficiency gains. As a result, customers have benefited significantly through the Earnings Sharing Mechanism, and have seen delivery rates remain relatively flat over the period. The Company has demonstrated that it has taken a leadership role in the stewardship of the environment, and public safety. The Company has an effective governance structure in place and has placed an appropriate emphasis on employee safety, retention, attraction and motivation, which have all contributed to financial success, in addition to the high levels of customer satisfaction that have been achieved in meeting the SQI's under the PBR Agreement.

The Company intends to maintain its focus on continuous improvement and its pursuit of Operational Excellence now and into the future. The next section of the RRA will describe how the Company looks to do this.

2. The Future

With the PBR Agreement set to expire at the end of 2009, Terasen Gas is taking action that reflects our ongoing commitment to being a respected and trusted operator, providing safe, reliable and cost effective natural gas service as well as providing a broader range of energy solutions to our customers into the future. Terasen Gas has a continued need to focus on Operational Excellence, including managing O&M and capital expenditures effectively and efficiently so that it continues to meet the increasing expectations of its customers, regulators and policymakers. The Company's commitment will include assistance and education that will allow British Columbians to understand the appropriate uses of different forms of energy leading to greater energy efficiency and conservation and promote the use of innovative energy technologies.

The Company intends to remain focused on continuous improvement and Operational Excellence in 2010 and 2011. The five key areas of management focus will continue to be:

1. Customer Service
2. Management Excellence
3. Operational Performance
4. Employees
5. Prudent Cost management

Below we outline what Terasen Gas must do in each of these areas if it is to continue to be a trusted, respected operator that meets the evolving needs of our customers.

2.1. We Intend to Meet the Evolving Expectations of Customers and Communities We Serve through the Delivery of Quality Service

Terasen Gas is proud of the level of service that it has provided customers throughout the PBR Period. Yet as it looks to the future, especially in light of the major challenges that have been identified in the External Situation Context Section, the Company recognizes that it cannot stand pat. Terasen Gas is of the view that it is critical to the long-term success of the Company and the customers we serve that it enhances its focus on efforts aimed at maintaining and improving customer service and satisfaction and that it does so across a broader suite of services and offerings.

Our customers and communities are increasingly looking for efficient energy solutions that support conservation. The province is encouraging and accelerating this movement through climate change policy and legislation as discussed previously. Terasen Gas is well positioned to work with customers and communities to provide integrated energy planning and solutions that allow them to address overall energy efficiency, climate change policy and legislation. The Company is committed to doing so. In addition to enhancing customer care service quality, Terasen Gas' initiatives, broadly speaking, are two-fold: (1) EEC programs; and (2) pursuing opportunities to provide alternative energy solutions.

The Company sees the following realities associated with providing service to customers in the future:

1. Terasen Gas must enhance its customer care service quality;
2. Terasen Gas' customers – and the province of B.C. – are increasingly looking for efficient energy solutions that support conservation, through EEC programs; and
3. Terasen Gas is committed to working with customers and communities to provide integrated energy planning and solutions that allow them to address overall energy efficiency, climate change policy and legislation.

These points are elaborated upon below.

2.1.1. Terasen Gas must Enhance its Customer Care Service Quality.

Although the Company has largely met targets related to the SQI's throughout the PBR Period, Terasen Gas recognizes it must enhance its customer care service quality going forward. To address the long-term provision of Customer Care services, on June 2, 2009, we have filed our Customer Care Enhancement Project application with the expectation that the new project components will go live on January 1, 2012. This is a critical component of the Company's long-term strategic direction. In the shorter term, as reflected in this Application, starting in 2009 and through the 2010/2011 forecast period the Company will be increasing its efforts to improve the quality of our customer care activities while bridging to an orderly transition for implementation of the new customer care delivery model effective 2012. The details are described in Part III, Section C, Tab 6.

2.1.2. Terasen Gas' Customers – and the Province of B.C. – are Increasingly Looking for Efficient Energy Solutions that Support Conservation through EEC Programs.

In the Company's recent EEC Application, a broad portfolio of EEC program areas was proposed. The Commission stated in its Decision, however, that the portfolio of programs was not comprehensive and would have to be augmented. The Commission's Decision directed Terasen Gas to pursue further EEC programs for industrial and low income customers. With this Application, Terasen Gas seeks approval to expand the existing EEC portfolio and spending in these areas in 2010 and 2011, with the same financial treatment reflected in the Commission's recent EEC Decision. The details of the proposal are described in Part III, Section C, Tab 3 of the Application.

2.1.3. Terasen Gas is Committed to Working with Customers and Communities to Provide Integrated Energy Planning and Solutions that allow them to Address Overall Energy Efficiency, Climate Change Policy and Legislation.

While there is a growing focus on energy efficiency and reducing the GHG emission coming from the consumption of this energy, Terasen Gas considers natural gas to be a foundational fuel that is an integral part of an efficient, integrated energy system. It will continue to play a significant role into the future. Alternative energy solutions are an important and complementary aspect of TGI's overall strategy to meet the evolving needs of customers and communities. Offering new and integrated alternative forms of energy, in conjunction with natural gas, also responds to the province's energy policy and climate action objectives.

It is incumbent upon Terasen Gas to have meaningful input into the development of policy and regulations, as well as undertake meaningful consultation with First Nations, other stakeholders and the public. We aim to continue providing information to, and enhancing our dialogue with, stakeholders, regarding appropriate energy solutions. Increasingly, however, customers expect Terasen Gas to not only provide information and advice, but to also deliver on a range of energy solutions including gas, energy efficiency and conservation and alternative energy. Terasen Gas intends to respond to climate change policy and legislation, and their implications for customers and communities, by offering integrated energy solutions, including the use of natural gas, that support the customers and communities of British Columbia reduce their carbon footprint. This will allow for the consideration of opportunities where natural gas is the right energy form in the right application, or where gas is a complementary fuel choice in an integrated solution where it might otherwise not have been considered on its own.

As stated above, there is a growing acceptance that comprehensive energy planning can be optimized within communities, or at a community and end-user level, as evident by the establishment of such organizations as QUEST in recent years. Energy can be managed and often used in a community setting more efficiently than if end users are working independently. For example waste energy (such as waste heat from a refrigeration process) within a community can be recovered rather than lost. Community boundaries include not only those most commonly defined on the basis of local government boundaries such as municipalities, but also at the neighbourhood level where a large residential development now incorporates energy planning in its development process, and at times may expand across municipal boundaries. QUEST White Paper I states that:

- *"The community, with its use of energy in houses, business, institutions, industry and transportation, is the most promising place to act.*

- *An integrated approach at that level allows balancing energy demand and supply between different sectors, accounting for the impact of one system versus the other, and leads to optimal results in providing community services.*
- *Integration of energy systems at the community level brings the maximum economic, social and environmental benefits."* [127]

The QUEST White Paper II also sets out the following six principles for consideration in designing energy systems:

- Improve efficiency – first, reduce the energy input required for a given level of service;
- Optimize "exergy" – avoid using high-quality energy in low-quality applications;
- Manage heat – capture all feasible thermal energy and use it, rather than exhaust it;
- Reduce waste – use all available resources, such as landfill gas, gas pressure drops and municipal, agricultural, industrial and forestry wastes;
- Use renewable resources – tap into local biomass, geothermal, solar, and wind energy; and
- Use grids strategically – optimize use of grid energy and as a resource to optimize the overall system and ensure reliability. [128]

It is with this view that Terasen Gas believes that it must offer more than natural gas to customers. We must also be involved at the community level to help promote energy efficiency and be able to provide solutions that are good both for existing and new customers.

The majority of B.C. municipalities have committed to the provincial government to become carbon neutral by 2012.[129] In turn this obligation will be reflected in local bylaws and thus change the way developers must plan for energy requirements, in the buildings and communities they design. Local governments have long been important partners for Terasen Gas, but they have now become even more critical to the long-run success of the Company. Using a community view, or QUEST approach, and the SMART Gas Strategy for BC[130], utilities can play a significant role in developing community energy solutions to meet community and customer needs. Accordingly, Terasen Gas is of the view that its proposal and its proposed costs associated with increased activity in this regard, as included in this Application are reasonable and appropriate.

[127] See Appendix C-22 for a copy of QUEST White Paper I
[128] See Appendix C-49 for a copy of QUEST White Paper II
[129] See Appendix C-17 for a copy of List of Local Governments who have signed B.C. Climate Action Charter
[130] See Appendix C-14 for a copy of A Vision for British Columbia's Energy Future: Smart Gas Strategies

Terasen Gas is committed to creating the long-term solutions and business models that will allow its customers and communities to permanently draw upon alternative sources of energy, often in conjunction with natural gas. The Company has undertaken projects that reflect this commitment. TGI will begin to offer the following alternatives in the next several years, as reflected in this Application:

i. Bio-gas
ii. LNG and CNG for transportation tariffs
iii. Solar Thermal
iv. Geo Thermal and,
v. District Heating

As set out in Part III, Section C, Tab 3, the Company proposes a regulatory model to facilitate our pursuit of opportunities in these areas. This model includes specific economic tests, similar in nature to the Company's Main Extension (MX) Test. The purpose of these tests will be to ensure that the cost of providing service to the prospective customers will not unduly impact existing customers. The addition of new customers who will bear a portion of system costs will help to offset the impacts of declining use rates on the existing customer base. Terasen Gas seeks approvals for various new rate schedules and recovery of the costs associated with providing these service to customers, as set out in Part III, Section C, Tab 3. We believe that it is in the interest of both existing and future customers that Terasen Gas not only be able to offer these services, but that the programs, development and sales costs of these activities for the forecast period form part of the costs to be recovered from customers as part of this RRA.

Terasen Gas' broad geographic presence in B.C., along with its core operating competencies, and our position of trust with our customers, positions us well to serve the evolving needs of customers and communities. Customers will realize the additional benefits of economies of scale and transparent regulatory oversight to ensure prudent and reasonable provision of innovative energy technologies and energy solutions applications. District energy systems, expanded EEC programs, participation in energy and community planning considerations, are all opportunities for a regulated public utility and are consistent with the expectations, goals, and objectives of government policy in B.C. and related regulations currently in place or under development.

2. Terasen Gas Intends to Continue to Pursue Excellence in Management and Enhance its Governance Structures

Our strong corporate governance structures (described in Part III, Section B, Tab 1), with clear division of management responsibilities and well defined policies and procedures have been instrumental in our success in achieving Operational Excellence. Terasen Gas must continue to invest in the controls and management constructs (including IT Systems) that will ensure that we continue to meet and exceed evolving corporate governance and regulatory requirements. Terasen Gas has identified several areas that require additional focus and new investment related to security, safety and business interruption preparedness as described below.

As a responsible operator Terasen Gas must continue to increase our efforts to improve safety measures. Terasen Gas must take the necessary steps to ensure an appropriate level of security for both its physical assets (pipes, stations and buildings) and soft assets (computer systems and infrastructure). This will include enhancing its capabilities related to disaster recovery, business continuity and emergency response programs. We also believe that there is a need to increase the awareness of customers and the public with respect to gas safety matters, in order to enhance public safety.

Terasen Gas also recognizes that improvements must be made if the Company is to be fully prepared to respond to business interruption, regardless of the event. Loss of access to applications and data for an extended period of time has been identified as a significant exposure of the organization that needs to be addressed. The majority of companies in the Energy and Utility industry have formal IT / disaster recovery plans and there is a significant increase in aligning emergency planning, business continuity and disaster recovery.

It will be critical to have an enterprise-wide strategy to mitigate risk from interruption. While some departments within the Company have implemented solutions to address their individual recovery requirements, a corporate solution does not yet exist and the organization is at risk.[131] Under the ownership of KMI, the direction was to utilize the existing KMI data centres and support staff for a formal Disaster Recovery site, providing significant cost reductions in capital and operating expenses. With the sale of Terasen to Fortis, that opportunity was no longer available so Terasen Gas is now undertaking a project to provide for technology disaster recovery and business continuity in the event that the data centre is lost or a Terasen Gas facility is inaccessible or both.[132] A comprehensive plan has been developed and the time has come to execute on this plan before any business interruption occurs, significantly hindering Terasen Gas' ability to meet the needs of its customers.

[131] i.e. SAP recovery provides financial statements, but would not support all of Finance nor any other business process utilizing it.

[132] Although detailed design and planning is not complete, the capital expenditure required for this capability is estimated to be in the $2M - $3M range and the ongoing operating cost to be almost $750K annually once completely implemented.

3. Continued Focus on Operational Performance and Operational Excellence into the Future

While Terasen Gas will continue to pursue Operational Excellence, the Company has exhausted opportunities for significant incremental efficiency gains. During the PBR Period, discretionary operating expenses as well as basic capital requirements have been consciously constrained without compromising safety, reliability, and customers have benefited from the resulting efficiency gains with the shareholder being incented to initiate such gains by sharing in a portion of the savings while under the PBR Agreement.

The current PBR Agreement has an efficiency factor equal to two-thirds of inflation, an implicit productivity improvement that is no longer sustainable. Certain expenditures, both O&M and capital, which had been pragmatically deferred cannot be deferred indefinitely. Expenditures will need to be made in the 2010/2011 forecast period. Terasen Gas has implemented a predictive maintenance model that has allowed it to manage more effectively its maintenance investments around mean time to failure, which has allowed us to achieve cost savings to the benefit of customers and the Company.[133] Similarly, during the PBR Period, the Company has improved its predictive modeling ability for corrosion growth on pipelines, which has allowed Terasen Gas to more accurately determine the required timing of pipeline inspections and digs.

We must continue to invest in the integrity and reliability of the energy delivery system. This means that the Company must continue to ensure it is compliant with all changing codes and regulations. Legislation such as the *Utilities Commission Act*, *Oil and Gas Commission Act*, *Workers' Compensation Act*, *Environmental Management Act*, *Safety Standards Act*, fire codes and safety standards, provincial and federal Emergency Acts, CSA Codes, and other legislation, regulations and bylaws define our corporate level of reporting and compliance activities. These have been introduced in Part III, Section A, and Terasen Gas' past performance was discussed in Part III, Section C, Tab 2.

To ensure ongoing compliance to existing codes and anticipated new or changed codes, additional operating and maintenance funding is required. There are four main drivers to the increases:

- Inflationary costs, i.e. increased internal/external labour costs, materials costs, etc.;
- Growth, i.e. more services to inspect/maintain, more ROW to clear, more external activity to control/monitor;

[133] Historically maintenance was performed on a scheduled basis, whether needed or not. During the PBR Period, maintenance was done in anticipation of failure.

- Asset age which increases risk profile i.e. more frequent inspections, more unplanned maintenance (repair), more replacements; and
- New or changed code requirements.

In addition to meeting these code requirements; Terasen Gas will continue to act as a responsible corporate citizen, having regard for the environmental impacts of our activities in the communities in which we do business. As the future unfolds with increases to the provincial carbon tax and the anticipated introduction of Cap and Trade systems, the Company must ensure it continues its leadership in its environmental stewardship activities, even though these activities will cause upward pressure on the Company's costs. The Company is of the view that a proactive approach will be more efficient than taking a wait and see approach.

4. Terasen Gas needs to increase its efforts in the Retention, Attraction and Development of its Employees

As a prudent operator, Terasen Gas must invest in the people who deliver for our customers: our employees. Notwithstanding the recent economic downturn, the Company is entering a critical stage in a labour market that is challenged on two fronts by an aging workforce and a limited supply of younger, skilled workers graduating from trades and technology programs. In order to remain competitive and continue to provide the service our customers expect, we need to strengthen the foundation of our end-to-end Talent Management systems and processes. This need lies at the heart of the long-term Human Resources vision to "Retain, attract, develop and motivate the right people to achieve desired business results". We must continue to invest in the development of employees and address the demographic shift that we will experience if we are to maintain the safe, secure and reliable service our customers expect.

One factor that has changed significantly for the Company is the challenge associated with recruiting qualified employees for many of the specialized positions we require at Terasen Gas. The recruiting environment in recent years has been a fluid one, shifting from employers having to be highly competitive in their efforts to attract and retain qualified workers, to the current situation of employees having fewer choices during a time when many employers in various industries are laying off staff rather than hiring.

The Business Council of British Columbia reports that:

> *"… despite a relative abundance of labour, ongoing churn, the highly specialized nature of many occupations and (at the margin) more retirements, employers are bound to have difficulty filling some positions. To some extent, there may be an emerging paradox of occupational specific shortages amid a large pool of people seeking work."* [134]

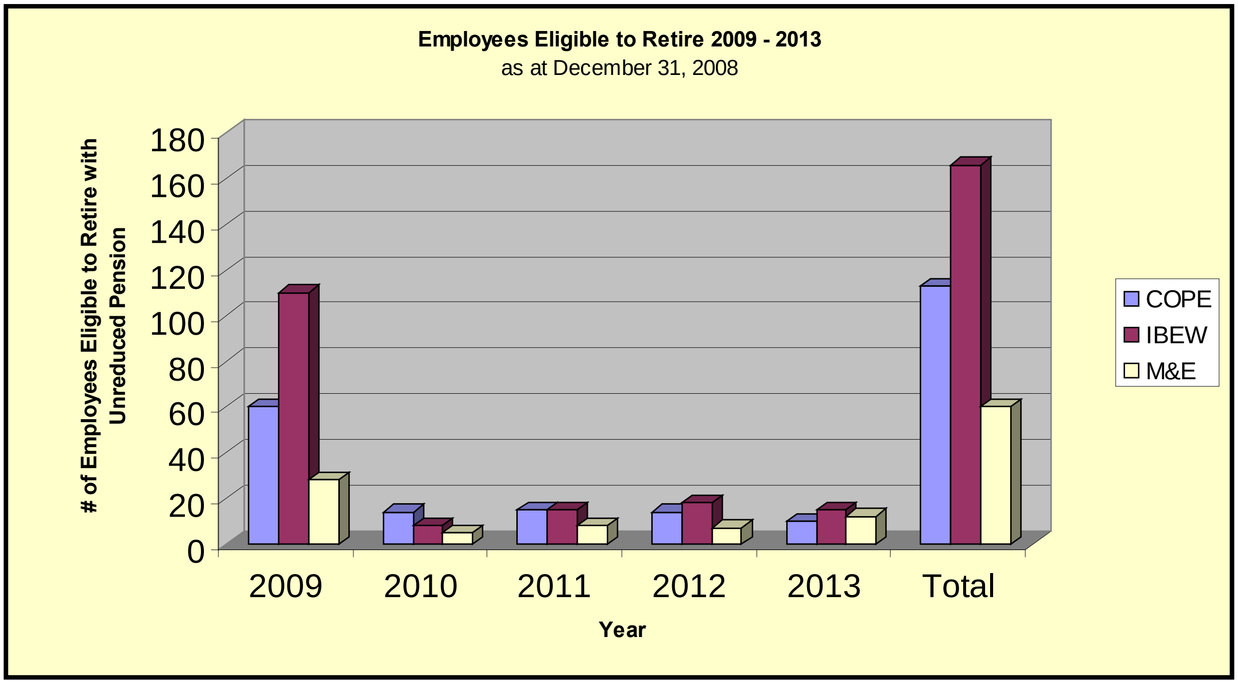
Compounding this challenge for Terasen Gas is that the Company is facing a significant attrition risk over the next 5 years as record numbers of employees become eligible for retirement. Terasen Gas' workforce challenge is characterized by a demographic profile which shows that more than 48 per cent of current employees become eligible to retire, with either a reduced or unreduced pension, within the next 5 years (Note: figures do not include executives and are based on HR metrics produced as of December 31, 2008). [135]

Roughly 16 per cent of Terasen Gas' workforce, or 198 employees, are eligible to retire in 2009 with an unreduced pension, yet these employees have chosen to continue working. While deferral of retirement may be seen by some as a positive development that buys the employer additional time, it only delays the inevitable and can actually compound the problem. If large numbers of employees defer retirement beyond the time when they might normally be expected to retire, the employer bears the risk and uncertainty of having large numbers of employees retire on relatively short notice, resulting in significant knowledge loss and insufficient time to hire and train replacement workers.

By 2013, eligibility to retire with an unreduced pension increases to 27 per cent (or 339 employees). Of those 339 employees, 113 are of COPE affiliation, 166 affiliated to the IBEW and 60 from M&E ranks. Normal employee attrition due to voluntary separation averages 3 per cent to 4 per cent per year (approximately 40 - 50 employees), which adds further pressure on the need to retain and attract workers. The aging issue is most pronounced with our IBEW workers where 41 per cent of the IBEW workforce is currently eligible to retire with unreduced or reduced pensions.

[134] See Appendix C-50 for a copy of A Paradox of Shortages Among Plenty?
[135] See Appendix F-2 for a copy of Headcount History and Demographic Data

Figure B-2-1: More Than one quarter of Terasen Gas Employees Are Eligible to Retire with Unreduced Pension Between 2009 to 2013



Note: The number of employees who meet the criteria to retire with an unreduced pension sometime in 2009 are NOT carried forward or included in the numbers for retirement eligibility for 2010 and beyond. Some employees are choosing not to retire when eligible.

Knowledge and productivity loss is costly to the Company. When employees leave, they take with them the experience and knowledge they have gained about Company information, processes and the business in general. In an October 2008 report, the Conference Board of Canada stated:

> *"The loss of corporate knowledge is another significant concern as workers retire. To meet this challenge, the most common strategy is to hire an incumbent's replacement prior to their retirement; this practice is slightly more common in the public sector (75 per cent) than in the private sector (64 per cent). The use of job shadowing is another approach that is also much more widespread in the public sector than in the private sector. In fact 40 per cent of public sector organizations use job shadowing as a knowledge transfer tool, as compared to just 15 per cent of private sector companies."* [136]

[136] See Appendix C-42 for a copy of Harnessing the Power: Recruiting, Engaging and Retaining Mature Workers

If turnover is gradual, replacements can usually be trained by the employees remaining behind. As well, productivity loss can more easily be absorbed because of the remaining employees' ability to work efficiently, support their new co-worker, and potentially work overtime hours.

The challenge posed by demographics is particularly acute within specific departments where pockets of employees are all eligible to retire within this time frame – potentially leading to the coincidental retirements of entire departments. This is a challenge facing departments with employees who are highly technical or specialized, such as Corrosion Control, Right of Way Inspection, Transmission operations, and LNG operations. As a result of this type of potential mass retirement, the Company has much less control and ability to stagger hires and facilitate knowledge transfer between employees.

When multiple employees leave departments at the same time, the productivity loss is multiplied, due to:

- Reduced productivity while new employees are learning their roles;
- Reduced productivity and customer service while positions remain unfilled (particularly if the time-to-hire is lengthy); and
- Increased short-term overtime costs while remaining employees fill in for departing or newly hired employees.

Depending on the size of the department and the number of people who leave, there may be limited (or no) resources available to train employees, or to continue the work of the department while new employees are being trained. When employees are not trained adequately, it creates potential safety and productivity issues, and can also result in breaches of standards, codes, and other regulations.

One of the best ways to train a new employee is to create a job-shadow arrangement that has the new employee working alongside the person they are replacing (or another employee who is familiar with the job). This gives the new employee:

- exposure to what the job is on a day-to-day basis;
- the opportunity to watch someone else perform the role;
- immediate access to someone who can evaluate work they've done and answer questions they have about the role.

However, it also results in increased training costs.

In a 2007 report, the CGA recognized that the degree and impact of an aging workforce is more pronounced for natural gas utilities than all other industries. It goes on to suggest that natural gas utilities must adopt different strategies to address the aging workforce population to ensure the continuation of a highly skilled workforce. In particular, the CGA recommends:

> *"Natural gas utilities need to develop strategies that allow for some redundancy and overlap between new employees and upcoming retirees. As well, new compressed training programs and innovative IT solutions will be required to better capture and transfer knowledge and experience. To facilitate this transfer of knowledge and experience, natural gas utilities will need to make new investments."* [137]

Terasen Gas is facing significant demographic challenges over the next several years which require additional resources to address. The need for additional funding to ensure a competent and knowledgeable workforce that is able to maintain safe and reliable service is recognized by the CGA:

> *"Costs will increase as natural gas distribution companies work to address the challenges associated with an aging workforce. The most significant cost increases will result from hiring replacement workers, increasing training programs, and the increasing cost of retention programs. It is estimated that a 1 per cent increase in operating costs could reasonably be expected by utilities immediately and that costs could escalate up to 5 per cent over the next few years."* [138]

As Terasen Gas looks forward, it needs to employ a variety of measures to ensure it has a skilled and competent workforce that sustains Operational Excellence for the benefit of customers and the shareholder. There are three areas where the Company intends to focus its enhanced efforts over the two year RRA period:

1. Recruiting and on-boarding;
2. Training and employee development, and;
3. Allowances for transitional headcount.

These areas of focus are summarized below, and are explained in detail, including associated cost impacts, in Part III, Section C, Tab 6 of the Application.

[137] See Appendix F-6 for a copy of Workforce Demographics: Addressing an Aging Workforce in the Natural Gas Distribution Sector
[138] Ibid

4.1. Recruiting and On-Boarding

Terasen Gas must continue to evolve and improve its employer brand, and strengthen its position as an attractive and competitive employer. This is necessary to ensure that the Company is able to attract people with the knowledge and skills to support its evolving business requirements. The Company intends to implement targeted recruiting and advertising campaigns with First Nations and associations representing technologists, technicians and professionals (i.e. ASTTBC, BCIT, CGA, APEG). The Company also intends to reach out to students, promote career opportunities and attract high performers for future employment opportunities through co-op and internship programs.

4.2. Training and Employee Development

The Company faces new challenges with regard to training and employee development. These challenges relate not only to the anticipated increased volumes of hiring activity, but also the changing skill-sets and competencies required. The Company is expanding beyond its traditional trades-focused training model to address the development needs of office employees and managers as well. At the same time, TGI and IBEW representatives are working together to identify internal progression pathways from entry level field worker to more highly skilled positions to promote development within the organization and build more capacity for the senior, highly skilled positions.

4.3. Allowances for Transitional Headcount

To transition knowledge, skill and work from retiring employees to the new work force, especially in those departments that are expecting mass coincidental retirements, Terasen Gas intends to hire transitional staff before retirements occur. The timeframe for any transitional hire will be determined for each individual job category within the departments based on complexity and the timing of the work process, in order to ensure effective knowledge transfer.

In summary, Terasen Gas is of the view that it is prudent to increase its efforts in the retention, attraction, and development of employees in order to effectively meet the evolving needs of customers over the next two years.

5. Prudent Cost Management to Provide for Efficiencies and Benefits to Customers

Terasen Gas is prudently managing costs and resources and drawing on improvements made over the course of the PBR Period. TGI is committed to continuing to provide for efficiencies and benefits to customers. The current challenges facing the Company, however, will cause Terasen Gas to increase investment in 2010 and 2011 in order to continue to meet the evolving needs of customers.

The required increase will result in:

1. Total operating expenses that increase, but which will be lower on a per customer basis than the 2003 Decision (after adjusting for inflation);
2. Capital costs that increase but are also lower on a per customer basis than those in the 2003 Decision (after adjusting for inflation); and
3. Significant upward pressure on the company's cost structure and delivery rates driven by changes to accounting standards.

These points are elaborated on below.

5.1. While Total Operating Expenses will increase slightly, they will remain lower in real terms than the 2003 Decision level on a per customer basis

The Company intends to continue to prudently manage its O&M expenses in order to deliver cost effective service to customers.

A comparison of Terasen Gas' O&M expenditures against other similar utilities shows that we are among the lowest on a per customer basis. As we look to the future, it is necessary to increase the total level of O&M expenses in order to address a number of the significant challenges facing the Company. This was discussed generally in the External Situational Context, and is discussed in more detail in Part III, Section C, Tab 6.

Increases notwithstanding, we anticipate that costs on a per customer basis after adjusting for inflation will continue to be lower than the amount included in the 2003 Decision. This represents continued, albeit modest, efficiencies as compared to the last test period reviewed through a revenue requirements application and hearing. The Company views its forecast O&M per customer as a significant achievement, and a clear demonstration of its continued pursuit of Operational Excellence into 2010 and 2011.

The items that will cause upward pressure on total gross O&M expenses in 2010 and 2011 (most of which the Company expects it would have sought "exogenous factor" treatment for, had the PBR Agreement still been in effect) are as set out below. These items have been briefly described earlier in this section and are described in more detail in Part III, Section C, Tab 6.

- The costs required to provide the products, services and meet the expectations of our growing customer base.

- The costs associated with meeting the increased governance requirements.
- The costs needed to meet our growing operating requirements associated with system and operational safety, integrity, and reliability.
  - Steps are required to ensure an appropriate level of security for our assets, including computer systems and infrastructure.
  - The awareness of customers and the public with respect to gas safety matters needs to be increased in order to enhance public safety.
- Expenditures that have been deferred, but which cannot be deferred beyond the forecast period.
- The costs associated with the challenges facing the Company with respect to its retention, attraction and development of its employees, including the significant demographic challenges described previously.

These items are described in more detail in Part III, Section C, Tab 6.

In summary, the forecasted O&M costs included in the Application are prudent and required for Terasen Gas to meet the evolving needs of customers and the communities that it serves.

5.2. Capital Costs will increase while, on a per customer basis, being lower than the 2003 Decision level after adjusting for inflation

Terasen Gas must continue to invest in the integrity and reliability of the energy delivery system in the future as well as continue to invest in the IT systems necessary to support business and growth. The capital forecast included in this Application (Part III, Section C, Tab 9) reflects our commitment to continue to make these types of prudent investments. The forecasted capital expenditures included in the Application are necessary for Terasen Gas to meet the evolving needs of customers and the communities that we serve.

5.3. Significant Upward Pressure on the Company's Cost Structure and Delivery Rates Driven by Changes to Accounting Standards

As described in the External Situational Context Section of this Application, over the course of 2010 and 2011 there will be considerable changes to financial reporting standards to which Terasen Gas will have to adhere. Although these changes do not affect the overall costs to be incurred by the Company, they do affect the timing of when costs are to be recognized, and therefore affect the cost structure of Terasen Gas for the forecast period. The most notable changes are changes to the methodology for recording depreciation expense and overheads capitalized, which are discussed in detail in Part III, Section C, Tab 11. Notwithstanding the fact that these items result in an increase in the Company's revenue requirements and rates for the forecast period, Terasen Gas believes that it is obligated to reflect these changes in its RRA.

Respected and Trusted Operator - Future - Conclusion

We must continue to provide safe, reliable and cost effective gas delivery service while beginning to offer alternative and integrated energy solutions in conjunction with natural gas. The future holds both great promise for the province of B.C., Terasen Gas and its customers, yet it poses significant challenges for all groups. The time has come, after the successes of the PBR Period, to make additional investments to meet the evolving needs of our customers, the communities we serve and our shareholder.

In the next twelve sections of this document we detail the proposals for which approval is being sought in this Application.

C. Continued Investments in Base Business and New Energy Solutions

1. Introduction

As TGI emerges from the six-year PBR Period, the overall picture is a favourable one with respect to the management of TGI's controllable costs. Customers have obtained a permanent benefit of significant savings during the PBR Period through prudent management. These efficiencies achieved through the PBR Period have translated into a lower starting point for our per customer O&M forecasts in 2010 (inflation adjusted) than was the case in 2003. However, significant changes in TGI's external operating environment, or what would have been characterized as "exogenous factors" under the PBR Agreement, have driven the need for a rate increase for 2010 and 2011.

The revenue requirements and proposed approvals outlined in this Application are grounded in TGI's commitment to meeting the needs of its customers, the communities in which it serves, and its shareholder, as well as investing in TGI's employees. As described in Part III, Section B, TGI must continue to invest in areas such as management excellence, customer service, operational performance, and human resources. The proposed rates for 2010 and 2011 will allow that to occur in a manner that will benefit customers and the Company going forward.

TGI has determined the Company's delivery margin revenue deficiency to be $27.9 million in 2010 and a further $21.9 million in 2011 (cumulative total of $49.8 million), as compared to revenue from existing 2009 delivery rates. The proposed revenue requirements for 2010 and 2011 result in an effective delivery rate increase of 5.3 per cent in 2010 and an additional effective base delivery rate increase of 4.1 per cent in 2011 (cumulative increase of 9.4 per cent over two years).[139] These proposed increases result in relatively modest changes to the annual bill of an average Lower Mainland residential customer with an approximate net increase of 2.8 per cent or $31 in 2010 and an additional 1.7 per cent or $19 in 2011.[140]

The major contributor to the forecast revenue deficiency in 2010 and 2011 is mandatory changes to accounting standards. The most significant of these accounting changes are:

[139] These delivery rate increases over the two year period, do not include the impacts of the proposed changes in ROE and Capital Structure Application that is before the BCUC. This process will have an impact on customers delivery rates if the application is approved as filed. The order sought in this Application contemplates the adjustment of permanent rates to reflect the Commission's decision in the ROE Application. The Terasen Gas Customer Care Application that is also before the BCUC will not impact rates until 2012, based on TGI's proposal.

[140] Based on typical annual consumption of a Lower Mainland residential customer consuming 95 GJ. This is also based on the current commodity and midstream charges effective April 1, 2009.

- reductions in the amount of overheads capitalized; and
- increases in depreciation expense.

These two items, in aggregate, account for a cumulative impact of $42.9 million in 2010 and $43.4 million in 2011. Accounting changes also impacted the forecast gross level of O&M expenses, as has the introduction of new codes and regulations and changes to government policy. In total, these three factors have contributed to an increase in the 2010 revenue requirements of $2.8 million and $4.5 million in 2011. But for these changes, the cumulative revenue requirements outlined in this Application of $27.9 million for 2010 and $49.8 million for 2011 would have been a revenue surplus of $17.8 million in 2010, and a deficiency of $1.9 million in 2011.

The total gross O&M expenses have increased from the level included in the 2009 projection; however, when considered on a per customer basis and after adjusting for inflation, the costs in both 2010 ($245) and 2011 ($249) are lower than those included in the 2003 Decision ($266), which formed the basis for the PBR Agreement. Terasen Gas views this result as a significant demonstration of the legacy of efficiency gains realized through the PBR Period, continuing to be in effect into the future for the benefit of customers.

The most significant offsetting factor in the 2010 and 2011 revenue requirements is savings resulting from the rebasing of the benefits achieved through the PBR Period. These savings total approximately $22.4 million and are composed of $6.7 million related to net O&M savings as TGI moves from a formula-based to a cost-driver approach to the O&M requirements, and a total of $19.3 million related to capital savings through reduced rate base and the tax-adjusted effects of reduced depreciation expense. These are offset by some changes in the calculation of late payment charge revenue and income taxes.

Another offsetting factor is an increase in sales margin and other revenues caused by increases in the customer base and increases in commercial use rates, and higher forecast SCP revenues. These amounts total $12.7 million in 2010 and $15.1 million in 2011.

In the next 12 sections of Part C, we describe in detail our plan for 2010 and 2011 to invest in our core gas business and also in alternative energy solutions which extend beyond our core business. The sections are organized as follows:

1. Introduction
2. Revenue Requirements and Rate Proposals

3. Energy Efficiency and Conservation Expenditures and Alternative Energy Solutions
4. Gas Sales and Transportation Demand
5. Cost of Gas
6. Operating and Maintenance Expenses
7. Taxes
8. Rate Base
9. Capital Expenditures
10. Capital Structure and Earned Return
11. Accounting Changes and Other Policies
12. Tariff Changes
13. Financial Schedules

In summary, TGI believes that the requested changes to rates and policies outlined in this Application are prudent and should be approved.

2. Revenue Requirements and Rate Proposals

The Company's revenue requirement reflects all of the inputs in the financial schedules, and takes into consideration all of the impacts described in this Application. The revenue requirement increases Terasen Gas is requesting are based on sound research and forecasting, utilizing our knowledge and experience to determine what the Company believes is the likely course of events over the upcoming forecast periods of 2010 and 2011.

We have determined the Company's revenue deficiency to be $27.9 million in 2010 and $21.9 million in 2011, (cumulative increase of $49.8 million) as compared to existing 2009 delivery rates. This is equivalent to an approximate effective base delivery rate increase of 5.3 per cent in 2010 and an additional effective base rate delivery increase of 4.1 per cent (cumulative increase of 9.4 per cent) in 2011.[141]

a) Revenue Requirements – Forecast Period

The following sub-sections 2 through 8 will discuss each separate component that makes up the total revenue requirement for 2010 and for 2011. The revenue requirement increases summarized below are required for Terasen Gas to continue to meet the needs of our customers, the communities in which we serve, and our shareholder, as well as invest in our employees.

[141] See Appendix J-7 for TGI's Proposed Tariff Continuity and Bill Impact Tables for 2010 and 2011

Table C-2-1: Revenue Requirements Reflect Needs of Stakeholders[142]

		2010 ($ Millions)		Incremental 2011 ($ Millions)	Cumulative 2011 ($ Millions)
Rebase from Formula Capital and O&M					
Rate Base- Net Plant in Service					
Equity Finance Expense	$ (2.0)		$ -		
Debt Finance Expense	(3.0)		-		
Utility O&M	(8.0)		-		
Overheads Capitalized	1.3				
After Tax Depreciation	(10.0)		-		
Tax Impacts of Rebase Depreciation	(4.3)		-		
Other Revenue	2.6		-		
Taxes	1.0	$ (22.4)	-	$ -	$ (22.4)
Volumes/Revenue Related					
Change in Gross Margin due to Customer Growth	$ (4.6)		(3.7)		
Change in Use Rate	(4.7)		4.7		
Change in Other Revenue	(1.6)		(1.9)		
All Others	(1.8)	(12.7)	(1.5)	(2.4)	(15.1)
O&M Forecast					
Change in overheads capitalized- change in O&M	(1.2)		(0.7)		
Change in O&M & Vehicle Lease Forecast	14.9	13.7	11.5	10.8	24.5
Depreciation & Amortization Forecast					
After Tax Change in Depreciation from GPIS Additions/Retirements	3.7		2.3		
Change in Amortization	(2.2)	1.5	4.0	6.3	7.8
Other					
Higher Property Taxes	1.6		1.0		
Change in Income Tax Expense	(0.4)		(0.1)		
Rate Base changes to support customer growth	1.8		2.5		
Interest Expense	2.1		5.4		
Rounding Difference	0.2	5.3	(0.1)	8.7	14.0
Total Revenue Increase/(Decrease) Before Accounting Standard Changes		$ (14.6)		$ 23.4	$ 8.7
Accounting Standard Changes					
Change in Overhead Capitalized Rate & Methodology	11.2		-		
Impacts on O&M	(0.3)	10.9	(2.0)	(2.0)	8.9
After Tax change in Depreciation Rates	20.8		0.4		
After Tax change in Depreciation Commencement	1.9		-		
Tax Impacts of Depreciation Changes	9.0	31.7	0.1	0.5	32.2
Total Revenue Increase from Accounting Standard Changes		$ 42.6		$ (1.5)	$ 41.1
Net Revenue Increase (Section C, Tab 13-1, Schedule 2 and 3, Column 6, Line 15)		**$ 27.9**		**$ 21.9**	**$ 49.8**

June 12, 2009

[142] See Part III, Section C, Tab 13, Schedule 1

As demonstrated in the table above, the main components of the increase in revenue requirements are the change in depreciation rates and policy associated with the adoption of IFRS, the change in the overhead capitalized also associated with the adoption of IFRS (both Part III, Section C, Tab 11), and the changes in operating and maintenance expense (Part III, Section C Tab 6), offset by the transitional impacts of moving from formula-driven capital and O&M expenditures to forecast.

(1) TRANSITIONAL IMPACTS – FROM FORMULA TO FORECAST

The 2009 revenue requirement was determined according to the PBR formula, and as such reflects the formula-driven capital and O&M amounts in both the 2009 costs and the 2009 rate base. The impact of the formula plant on the 2009 rate base is a decrease of approximately $69 million which translates to a decreased revenue requirement of approximately $5.0 million. In addition, embedded in the 2009 revenue requirement was $8.0 million of formula versus forecast O&M (net $6.7 million including capitalized overheads) and $10.0 million of formula versus forecast depreciation expense which together translate into an $21.0 million decrease in revenue requirement when comparing formula to forecast (the depreciation impact is grossed up for taxes). These revenue requirement decreases are somewhat offset by a decrease in the amount of late payment charge revenue of $2.6 million, which had been calculated under a formula, and a $1.0 million increase in tax expense resulting from changes in timing differences. The total of all these impacts is a decrease in the revenue requirement of $22.4 million resulting from moving from formula to forecast.

(2) GAS SALES AND TRANSPORTATION

For purposes of calculating the change in revenue requirement, there are a number of items within Part III, Section C, Tab 4, Gas Sales and Transportation that have a significant impact, the largest of which in 2010 and 2011 is the increase in volume associated with customer growth.

Table C-2-2: Customer Growth Results in Decreased Revenue Requirements

	($ millions) 2010 vs 2009	2011 vs 2010
Growth in Residential customers	(1.7)	(2.0)
Reduction in use rates for Residential customers	4.7	4.8
Growth in Commercial customers	(2.9)	(1.7)
Increase in use rates for Commercial customers	(9.4)	(0.1)
Growth in other core customers	(0.8)	0.1
Decline in use rates for other core customers	0.4	0.1
Growth in industrial customers	(1.9)	(1.8)
Increase in SCP revenues	(1.7)	(2.0)
Decrease in other revenues	0.1	0.1
Change in forecast industrial customer volumes	0.5	0.1
	(12.7)	(2.4)

The items in the table above are discussed more fully in Part III, Section C, Tab 4, and have been properly reflected in the calculation of the Company's revenue requirement.

(3) OPERATIONS AND MAINTENANCE EXPENSES

As discussed in Part III, Section C, Tab 6, O&M increases from 2009 projection are required In order to meet the evolving needs of our customers and shareholder and to provide safe, reliable and cost efficient service to customers. The business drivers behind these O&M changes on the 2010 and 2011 revenue requirements are summarized in the table below.

Table C-2-3: O&M Funding to meet our Customers' Needs Results in Increased Revenue Requirements[143]

	($ millions) 2010 vs. 2009	2011 vs. 2010
Labour inflation and benefits	2.8	5.3
Government policy	0.6	0.1
Codes and Regulations	5.2	2.1
Customer Expectations	4.5	0.6
Demographics	0.8	0.2
Accounting Changes	(3.1)	(0.5)
Service Enhancements	3.6	1.7
Total	14.4	9.5

The items in the table above are discussed more fully in Part III, Section C, Tab 6, and have been properly reflected in the calculation of the Company's revenue requirement.

[143] See Part III, Section C, Tab 6, Table C-6-3 O&M Incremental Funding to Meeting our Customers Needs

(4) CAPITALIZED OVERHEADS

As discussed in Part III, Section C, Tab 11 Accounting and Other Policies, IFRS requirements allow only directly attributable overhead to be capitalized. Terasen Gas has completed a study of overheads capitalized under IFRS guidelines, which has resulted in a decrease in the overheads capitalized rate from 16 per cent of adjusted Gross O&M to 8 per cent of Gross O&M. The impact of this on revenue requirements is a decrease in overheads capitalized and resulting increase in revenue requirements of $11.2 million. This impact is offset in both years by increased capitalized overhead on higher gross O&M (2010 impact is $1.2 million with an additional impact in 2011 of $0.7 million).

(5) DEPRECIATION AND AMORTIZATION EXPENSE

As discussed in Part III, Section C, Tab 11, Accounting and Other Policies and also Part III, Section C, Tab 8, Rate Base, there have been significant changes to the calculation of depreciation expense as a result of IFRS. This has resulted in an increase to depreciation expense of $22.7 million. Of this, $20.8 million is related to an updated depreciation study and a further $1.9 million results from a change in the timing of commencement of depreciation. Additions in 2010 and 2011 have resulted in higher depreciation expense of $3.7 million in 2010 and a further $2.3 million in 2011. Since the impacts on depreciation of the accounting changes are not deductible for income tax purposes, the total impact on revenue requirements for these items needs to be grossed up. The revenue requirement impact of all of these changes is an increase of $35.4 million in 2010 and a further $2.8 million in 2011.

In addition, amortization expense has declined $2.2 million in 2010 but then increased $4.0 million in 2011. Both of these amounts are after-tax, so the impact to revenue requirements is as stated.

(6) TAXES

As discussed in Part III, Section C, Tab 7, forecasted levels of property taxes and changes in income tax rates, new taxes, and changes to CCA rates all have an impact on the revenue requirement calculation. The property tax increases of $1.6 million and a further $1.0 million in 2011 both serve to increase revenue requirements. Other changes to income tax rates and timing differences will result in an offsetting decrease in revenue requirements in 2010 of $0.4 million and 2011 of $0.1 million.

(7) RATE BASE

Terasen Gas earns a return on rate base, so changes in the amount of rate base affect the amount of return included in the revenue requirement by approximately 3.0 per cent of that change. The rate base proposals contained in Part III, Section C, Tab 8 Rate Base contribute $1.8 million to the 2010 revenue requirement and a further $2.5 million to the 2011 revenue requirement.

(8) FINANCING COSTS

The final component of the revenue requirement calculation is financing costs. Financing costs are discussed in Part III, Section C, Tab 10, Capital Structure. The amount of financing required is determined by the rate base; the financing costs themselves are determined by a combination of the amount of financing and the forecast interest rates. Increases in financing, caused by higher rate base, results in $4.7 million of additional financing costs in 2010 and $6.6 million of additional financing costs in 2011. This is offset in both years by changes in interest rates, mitigating this impact by $2.6 million in 2010 and $1.2 million in 2011, resulting in a net increase associated with financing costs of $2.1 million in 2010 and an additional $5.4 million in 2011.

The revenue requirement changes discussed above are translated into customer delivery rate impacts by comparing the resulting revenue deficiency with the existing gross margin. The percentage change is applied to all existing delivery rates.

b) Rate Proposals

In this RRA we are proposing changes to the volumetric and demand based delivery charge, the earnings sharing mechanism rate rider ("ESM Rider") and the revenue stabilization adjustment mechanism rate rider ("RSAM Rider").

<u>Delivery Rates</u>

The proposed delivery rates reflect the 2010 and 2011 revenue requirements and result in an effective delivery rate increase of 5.3 per cent in 2010 and an additional effective base rate delivery increase of 4.1 per cent in 2011 (cumulative increase of 9.4 per cent). [144]

To support our Energy Efficiency and Conservation Program and to meet the evolving needs of our customers, we propose that the basic charge and administration fees be held at existing approved 2009 levels. As such, the proposed volumetric and demand based delivery rates have been adjusted to account for the revenue that would have been collected from the changes in the basic charge or administration fees in 2010 and 2011.

Moving towards a larger volumetric component of the bill enhances the ability of our customers to experience benefits gained by reducing their usage through their participation in our EEC programs as well as through their overall energy efficiency awareness.

[144] See Appendix J-7 for TGI's Proposed Tariff Continuity and Bill Impact Tables for 2010 and 2011

ESM Rider (Delivery Rate Rider 3)

The ESM Rider reflects a 2009 projected earning sharing amount owing to customers of $18.0 million at December 31, 2009. As noted in the Rate Base discussion (Part III, Section C, Tab 8) we are proposing that this balance be returned to customers over a two-year period as opposed to the one year period as approved in Commission Order No. G-51-03, to align the ESM rider with the impact of the End-of-Term Capital Incentive Sharing Mechanism and to smooth out the rate impact associated with the expiration of the ESM rider.

In addition to the 2009 projected balance owing to customers, a true-up of $0.7 million for the 2008 actual ESM amount is reflected in the 2010 rider. The ESM amounts for 2010 and 2011 are offset by the End of Term Benefit Mechanism applicable for each year of $3.6 million and $1.5 million respectively (total of $5.1 million).[145] All three components result in a credit rate rider of $0.040/GJ in 2010 and a further credit of $0.006/GJ in 2011, resulting in a total credit rider of $0.046/GJ in 2011, for a Rate 1 Residential customer.[146]

[145] Part III, Section B, Tab 2 Respected Operator, page 179 discusses the End of Term Benefit Mechanism and Part III, Section C, Tab 13, Schedule 69 provides the details of the calculation of the End of Term Benefit Mechanism applicable for 2010 & 2011

[146] Part III, Section C, Tab 13, Schedule 70

RSAM Rider (Delivery Rate Rider 5)

The RSAM Rider reflects a projected balance of $13.2 million owing to customers at December 31, 2009. As noted in Part III, Section C, Tab 8, RSAM account balances will continue to be recovered from or returned to customers through Delivery Rate Rider 5 over a three year period. This results in a credit rider of $0.053/GJ in 2010 which is reduced by of $0.001/GJ in 2011 for a total rider $0.052/GJ in 2011 applicable to Rate Schedules 1, 2, 3, and 23.

Interim Rate Reliefs

As indicated in Section D, since a Decision on this RRA may not be in time for permanent rates to be implemented on January 1, 2010, Terasen Gas requests approval for interim rates effective January 1, 2010. The interim rates would apply to all non-bypass customers whereby the margin increase in rates calculated and shown on Financial Schedules (Part III, Section C, Tab 13, Schedules 22 and 24) would be made effective on an interim basis on January 1, 2010. Any refund or under collection would be dealt with by way of a rate rider to refund or collect from customers the variance in interim rates versus permanent rates approved.

c) Summary

The Company's revenue requirement reflects all of the inputs in the financial schedules, and takes into consideration all of the impacts described in this Application. The revenue requirement increases of $27.9 million in 2010 and $21.9 million in 2011 are based on sound research and forecasting, using our knowledge and experience to determine the most likely course of events over the forecast period.

When combined with the proposed ESM and RSAM rate riders, the changes in delivery rates required to address the revenue deficiencies in 2010 and 2011, result in relatively modest changes to the annual bill of an average Lower Mainland residential customer, with an approximate net increase to the annual bill of 2.8 per cent or $31 in 2010 and an additional 1.7 per cent or $19 in 2011. [147]

[147] Based on a typical annual consumption of a Lower Mainland residential customer consuming 95 GJ. This is also based on the current commodity and midstream charges effective April 1, 2009.

3. Energy Efficiency and Conservation and Alternative Energy Solutions

To remain a viable energy provider TGI must be able to offer complete energy solutions representing our base natural gas business in combination with both EEC programs and alternative energy solutions. TGI is well positioned to work with customers and communities to provide complete energy solutions and is committed to doing so.

Terasen Gas' proposal for 2010 and 2011 is:

1. Increase EEC funding for 2010 over the currently-approved EEC funding to add interruptible Industrial customer programs and Innovative Technologies programs to the EEC portfolio, with all funding subject to the same financial treatment as approved in the EEC Decision;
2. Reallocate funding from the amount approved in the EEC Decision for 2010 to low income and rental housing programs;
3. Extend funding for 2011 for the entire EEC portfolio consisting of the above and currently-approved EEC program areas, with all funding being subject to the same financial treatment as approved in the EEC Decision;
4. Recovery in a deferral account of the revenues and ongoing O&M and the related expenditure of capital related to investment in energy solutions in NGV and alternative energy.
5. Approval of Tariffs for Rate Schedule 6C – Natural Gas Compression and Refuelling Service and Rate Schedule 26 – Natural Gas Vehicle Transportation Service, and subsequently the cancellation of Rate Schedule 6A – General Service – Vehicle Refuelling Service.
6. Approval of the economic models for evaluating new community energy solutions, and the proposed streamlined regulatory processes for approval of individual projects.

The approvals sought are reasonable and prudent and should be approved.

a) Energy Efficiency and Conservation Programs

The proposed increase in funding to support EEC programs for Interruptible Industrial customers as well as funding for specific Innovative Technology programs is consistent with the Commission's EEC Decision. The EEC funding sought for 2011, which matches the level of 2010 EEC forecast spending, will permit the ongoing funding in program areas approved in the EEC Decision. We believe that the requested EEC funding is prudent and in the interests of customers

On May 28, 2008, TGI and TGVI filed their EEC Programs Application, for funding of EEC programs for the 2008-2010 period. The application requested approval for a total of $56.6 million (for both TGI and TGVI collectively), capital treatment and amortization period of 20 years, and a portfolio methodology for evaluating the costs and benefits of the overall EEC portfolio. On April 16, 2009, TGI and TGVI received

BCUC Order No. G-36-09 which approved funding in aggregate of $41.5 million ($34.4 million for TGI and $7.1 million for TGVI), capital treatment of all expenditures with an amortization period of 10 years, and approval of a portfolio approach to evaluating the costs and benefits of the overall EEC portfolio. The Companies did not receive approval for expenditures for innovative technologies and the Companies were directed to bring forward projects in this program area for consideration as the projects become more fully developed. The Companies were directed to commence a planning process for the development of an Industrial EEC program and file a report with the Commission within 90 days of the Decision. The Company proposes that this reporting requirement is satisfied with the Industrial EEC information included in this filing. The Companies were also directed to proceed with a Joint Initiative relating to Affordable Housing and the Commission encouraged Terasen Gas to consider re-allocating funding from other approved areas of its overall spending as may be suitable.

Table C-3-1 shows the breakdown of approved 2008-2010 funding by regulated entity and the expected timing of expenditures for 2009 and 2010.

Table C-3-1: EEC Approved Funding for 2008-2010

	2008		2009		2010	Total
	O & M	Deferral	O & M	Deferral (Forecast)	Deferral	
TGI ('000s) Programs as per EEC	$ 1,740	$ 744	$ 1,624	$ 7,258	23,075	**$ 34,441**
TGVI ('000s) Programs as per EEC	$ 452	$ -	$ 497	$ 1,379	$ 4,726	**$ 7,054**

We are seeking approval for funding in 2011 for program areas outlined in the EEC Application and already approved by the Commission for 2010, with the reallocation of some of these funds to low income and rental housing programs as described below. TGVI will be seeking approval for similar EEC expenditures in its revenue requirements application to be filed later this month. We are also seeking approval of funding for 2010 and 2011 for Interruptible Industrial programs as well as funding for specific programs under Innovative Technologies. For TGI in 2010, these new programs add $2.8 million to the amount approved by BCUC Order No. G-36-09. An additional $6.5 million for 2011 is being sought for Interruptible Industrial programs and Innovative Technologies. This spending is outlined in the table below. The funding for EEC activities represents a placeholder for total dollar amounts that can be used to delivery programs to the benefit of customers. This funding envelope represents the total amount of dollars that would be spent by the Company on EEC activities for 2010 and 2011. However, over time, only the actual spend on EEC activities will be charged to the EEC deferral account and ultimately reflected in customers delivery rates.

Table C-3-2: EEC Funding Sought for 2010 and 2011

	2008		2009		2010	2011
	O & M	Deferral	O & M	Deferral (Forecast)	Deferral	Deferral
TGI ('000s) Programs as per EEC	$ 1,740	$ 744	$ 1,624	$ 7,258	23,075	$23,075
Interruptible Industrial					$ 435	$ 1,875
Innovative Technologies					$ 2,334	$ 4,669
TGI Total					**$ 25,845**	**$29,619**

The basis for the funding requests is outlined in the following sections.

(1) 2011 EEC PROGRAMS

As noted, Terasen Gas wishes to extend to 2011 the programs approved by the Commission in Order No. G-36-09 for the three year period 2008-2010. The expenditures for 2011 are set to match the forecast expenditures for 2010. The breakdown of the programs and cost are the same as that approved in the EEC Application Decision, as outlined in the table below.

Table C-3-3: EEC Program Breakdown and Cost for 2011

2011 Program Area Description		Budget Amount (000)		
		Incentives	Non-incentive Costs	Total
Residential	Energy Efficiency	$2,818	$1,257	$4,075
Commercial	Energy Efficiency	$10,471	$4,292	$14,763
Residential	Joint Initiatives	$1,010	$337	$1,346
Residential	Conservation Education and Outreach	$0	$1,445	$1,445
Commercial	Conservation Education and Outreach	$0	$1,445	$1,445
Total		$14,299	$8,776	$23,075

We believe that these programs and expenditures are consistent with the approvals already received for the years 2008-2010 and therefore should be approved by the Commission. The basis for the funding in these areas was outlined extensively in the EEC Application. In support of this request TGI relies on information and appendices filed in the EEC Application that have been identified and included in Appendix G-1.[148] This information includes the Conservation Potential Review ("CPR") and the Habart

[148] Included in Appendix G-1, included the TGI's 2008 EEC Application and Appendices 1, 9, 10, 11 and 12

report used to refine the results of the CPR. The evidence demonstrates the benefits of extending funding for a further year.

TGI will use the same portfolio approach and same financial treatment as that approved in BCUC Order No. G-36-09 to assess TGI's EEC expenditures. The portfolio approach allows flexibility in allowing the Company to redirect dollars from one program area to another as long the TRC test for the portfolio as a whole is 1.0 or greater. In this case, the portfolio under consideration would include all EEC programs, i.e. the previously-approved funding as well as the proposed new funding.

(2) RE-ALLOCATION TO LOW INCOME PROGRAMS AND RENTAL HOUSING

Of the EEC funding approved for 2010 and requested for 2011, TGI will allocate a minimum of $800 thousand to conservation for the low income and rental housing sector, with the potential for an additional re-allocation. The minimum proposed amount of $800 thousand for EEC activity for the low income and rental housing sector is based upon the annual proposed expenditure in the Joint Initiatives program area of Terasen Gas' EEC Application, and approved in BCUC Order No. G-36-09. We are in the process of implementing EEC programming for the low income and rental housing sector for the 2009 - 2010 period. As such we believe we will be able to increase the funding toward the low income and rental sector above $800 thousand. It is our intention to re-allocate an additional $1.6 million in funds from both the Residential and Commercial programs outlined above to low income and rental programs in each of 2010 and 2011.

(3) INDUSTRIAL ENERGY EFFICIENCY

This Application sets out our plan for the development of industrial programs including a revised Manufacturing and Industrial Conservation Potential Review ('CPR"), stakeholder meetings, program development and lastly funding requests. As such, it addresses the following Commission directives in BCUC Order No. G-36-09:

> *"The Commission Panel takes note of the MEMPR Letter of Comment, and directs Terasen to commence the planning process for the development of an industrial EE program and to file a report outlining the process contemplated and scheduling of the development plan with the Commission for review within 90 days of this Decision. The matters addressed in the report should include those raised by MEMPR in Exhibit C4-1."*

Exhibit C1-4 (not C4-1) from the MEMPR broadly states that it notes the absence of an industrial energy efficiency program and that this may result in missed opportunities for energy reduction. The MEMPR goes on to further state that:

> *"Ministry submits that the Commission include in its final determination on the Application:*
>
> 1. *A requirement for the Companies to refine the CPR for the manufacturing sector at the earliest opportunity.*
>   a. *Include the Companies' largest manufacturing accounts in the CPR.*
>   b. *Identify and develop specific DSM measures for the manufacturing sector.*
> 2. *The Commission should establish a timeline for the Companies to submit for approval a supplemental application for manufacturing sector DSM measures."*

With respect to the development of EEC programs for manufacturing sector, it is important to note that the approvals received via BCUC Order No. G-36-09 actually do include funding for industrial customers. The funding approved so titled "Commercial" customers includes those customers in sales Rate Schedules 2, 3, 4, 5, 6, and transportation Rate Schedules 23 and 25. Of these, TGI considers Rate Schedules 4, 5, 6, 23 and 25 to represent primarily large commercial and industrial customers[149][150]. Therefore the only customers who do not currently have access to any funding, and for which additional funding is required, are those in the Interruptible Rate Schedules 7, 22 and 27. For customers in Rate Schedules 4, 5, 23 and 25, there is currently sufficient funding available, but TGI needs to further develop manufacturing process load programs for customers in Rate Schedules 4, 5, 23 and 25.

Key in developing industrial and manufacturing programs for customers served under Rate Schedules 4, 5, 23 and 25 as well as interruptible Rate Schedules 7, 22 and 27 is that since the time of both the Conservation Potential Review - Manufacturing Sector Report ("Manufacturing CPR") (commissioned in 2006) and the EEC Application, the industrial sector has significantly changed in scope and scale (this is further referenced in Part III, Section C, Tab 4). Primarily, volumes have decreased in the industrial sector as a result of changes in the marketplace, fuel switching alternatives and changes in economic drivers. For example the Manufacturing CPR identified a number of opportunities in the forestry and greenhouse sector. Since the time of the Manufacturing CPR, forestry has significantly declined with many operations either closed, idled and in a number of cases, in bankruptcy proceedings. Those that are operational may have difficulty raising capital for asset expenditures or have already taken steps to become efficient and that has partly led to their resilience. Similarly, nearly all greenhouses have

[149] Note that in Rate Schedule 23 and 25, customers represented include heavy industry, strata corporations, institutions. This is covered in greater detail in Section 5 of this application.

[150] Note that the programs described in the EEC Application do not include programs for industrial process energy efficiency programs for these rate schedules.

installed wood waste systems used as their primary energy source. Gas has been used only as a backup; although due to recent low gas prices and increases in wood waste prices and lack of wood waste, we have seen an increase in gas use as a primary fuel. As a result of these changes there may not be as significant an opportunity for gas related EEC programs for these industrial groups.

To ensure that TGI provides programs that meet the customer's needs, TGI needs to better understand the economic and environmental drivers of this diverse group of customers. TGI proposes the following process for the design and implementation of a program to develop both programs for firm industrial customers served under Rate Schedules 4, 5, 23 and 25 as well as programs and funding for interruptible customers served under Rate Schedules 7, 22, and 27.

(a) Stakeholder Consultation

Stakeholder input is crucial to the development of any industrial EEC program due to the relatively small number of customers on industrial rates and the potential for the relatively large incentives needed to spur activity in the industrial sector negatively impacting rates for non-participants. TGI convened a workshop with industrial customers, the MEMPR and other stakeholders on May 19, 2009. Through this workshop and comments received from participants, it became apparent that TGI must do more work to develop programs to meet EEC needs of this group of customers. There was support for additional funding and programs and energy efficiency audits. However, participants and TGI acknowledged:

- TGI does not have experience with developing industrial programs, and will require further time to develop suitable programs; and
- Incentives and programs may have to be unique to either the industrial group or in many cases the individual customer.

We will convene further industry specific workshops, and customer meetings concurrent with the RRA process. The input gathered in the additional meetings and workshops will be invaluable in developing industrial EEC programs.

(b) Update to 2006 Manufacturing Sector Report in Terasen Gas CPR

TGI will commission an update to the 2006 Manufacturing CPR. It has now been three years since the last Manufacturing CPR, and the market has changed significantly since the report was originally received by the Company in May 2006. An updated report will give the Company a very high-level indication of the size and nature of EEC opportunities in this sector. The findings will be then be validated with the MEMPR Industrial DSM Stakeholder Group.

(c) Initial High-Level Budget

The budget below represents TGI's initial, high-level estimate of the expenditures that will be required to support EEC activity for the interruptible industrial sector for 2010 and 2011. It includes funding for: activity related to the workshops and customer meetings; an additional staff member with expertise in the Industrial and Manufacturing Sector; and, a series of in-depth energy savings potential studies, or mini-CPRS, with individual customers in the food processing, manufacturing and forest products sectors in 2010. Collectively the workshops, meetings with individual customers, updated Manufacturing CPR and audits in 2010 will provide data for evaluating the provision of incentives budgeted for 2011. TGI expects that the learnings from programs in 2010 and 2011 will help form the basis for expanded programs in the period 2012 forward.

Table C-3-4: TGI's High-Level Budget of the Expenditures Required to Support EEC Activity for the Interruptible Industrial Sector for 2010 and 2011

Industrial EEC	
Preliminary Budget for RRA	
2010	
Item	**Budget Amount**
Stakeholder Activity	$5,000
Additional position to administer Industrial DSM Program	$120,000
Consultant Update to 2006 Manufacturing CPR	$100,000
Energy Savings Potential Studies	
Food Processing Sector (3)	$60,000
Manufacturing Sector (3)	$60,000
Forest Products Sector (3)	$90,000
Total Year 1	**$435,000**
2011	
Item	**Budget Amount**
Stakeholder Activity	$5,000
Additional position to administer Industrial DSM Program	$120,000
Incentives	
Food Processing Sector (1)	$500,000
Manufacturing Sector (1)	$250,000
Forest Products Sector (1)	$1,000,000
Total Year 2	**$1,875,000**

TGI will continue to provide leadership developing expanded EEC programs. We believe that the process for determining programs described above is prudent and will result in appropriate industrial energy efficiency program needs. The funding request is reasonable and necessary to initiate a successful suite of industrial programs in the manner directed by the Commission. We respectfully request that the Commission approve the above noted funding for industrial EEC.

(d) Innovative Technologies

In its April 16, 2009 decision on TGI and TGVI Energy Efficiency and Conservation Application, the BCUC stated that:

> *"The Commission Panel considers that Innovative Technologies, NGV and Measurement programs can be appropriate vehicles for encouraging commercial development of technologies to reduce or replace natural gas consumption and related GHG emissions."*

The BCUC further stated that:

> *"The Commission Panel finds that there is insufficient evidence with respect to the nature and scope of the proposed program, and accordingly rejects the Innovative Technologies, NGV and Measurement program expenditures at this time. Terasen may wish to bring forward projects in this program area for consideration as they become more fully developed."*

TGI has since evaluated the market and need for innovative technologies. This Section of the Application provides an overview of EEC initiatives we intend to pursue through the use of innovative technologies. TGI's proposed programs are in the interests of customers and therefore should be approved.

(e) Residential and Small Commercial

Hydronic Based Heating Systems - Hydronic heating systems use liquid (water with corrosion inhibitors) to distribute energy for space and domestic hot water heating through a supply and return closed-loop piping system.

The flexible nature of this system ensures that the energy input can be changed with changes in technology and public policy, thus promoting a more sustainable energy design. An old low efficiency boiler can be upgraded to a high efficiency condensing boiler. Later the customer installing the boiler may be able to obtain energy from a district energy heating system, biomass, ground or solar energy sources. By utilizing this hydronic based heating systems for space and domestic hot water heating, an owner will be in a position to replace or supplement one type of energy source with another source as technology advances.

Given existing technologies, upgrading from a low efficiency boiler to a high efficiency boiler could result in a 20-30 per cent reduction in a residential customer's natural gas consumption. For the average family home this alone would be equivalent to 725 to 900 Kg of CO2e/yr. Similar reductions of 20-30 per cent in natural gas consumption in the small commercial sector could be achieved when upgrading from a low efficiency boiler to a high efficient boiler.

The cost on average for hydronic underfloor system materials is estimated to be about $4,000, not including the cost of the boiler. The average cost of hydronic baseboard materials is estimated to be approximately $2,000, again not including the cost of the boiler. In order to promote a sustainable energy design, the Companies will provide incentives up to 25 per cent of cost of the hydronic under floor piping materials (oxygen barrier tubing) to a maximum of $1,000 and hydronic baseboard materials up to 25 per cent and a maximum of $500. For 2010 spending will equal $778 thousand and for 2011 spending will equal $1.6 million for a two year total of $2.3 million.

Integrated Energy Systems (or Combination Systems) - Integrated Energy or Combination Systems are defined as a single appliance supplying both space and domestic hot water ("DHW") heating. Combo heating systems can be cost effective and increase the operating efficiency of tank-style water heaters by reducing their normal standby energy losses. The hot water tank can be connected to a fan coil to provide forced air heating, and the fan coils can be upgraded to provide air conditioning as well. Combo systems can also be connected to in-floor tubing to provide in-floor radiant heat.

TGI is already encouraging efficient boilers in new construction with heat exchangers through the existing Efficient Boiler Program, although the smallest boiler is 300,000 Btu/hour, thus excluding residential boilers from this program. There is a possibility that more high efficient hot water tanks could be utilized in combo systems.

Standard gas hot water tanks are about 60 per cent efficient. Improving the energy efficiency of domestic hot water heating to above 90 per cent efficiency will reduce GHG emissions.

A program to fund high efficiency (condensing) hot water tanks used for space and domestic hot water heating would help to drive demand for high efficiency gas hot water tanks. Right now these types of tanks cost approximately $3,000-$3,500 compared to $450-750 for a standard gas hot water tank. Installation costs would be comparable for both tanks. Instantaneous or tankless systems can be used for this application as well. Given that the average single family dwelling annually consumes 25 GJs of gas for domestic hot water, moving from 60 per cent to 90 per cent efficiency would produce savings of about 8.3 GJs per household per year. This could equate to a reduction of about 400 kilograms/year of CO2e. We will provide incentives up to 25 per cent of total cost of condensing hot water tanks to a maximum of $1000. This will equate to incentives of $518 thousand for 2010 and $1 million for 2011 for a total o f$1.5 million for the RRA period.

Solar thermal - A subset of hydronic heating systems, solar thermal systems also use water or glycol heated by the sun, with the thermal energy used for space and domestic hot water heating. Solar thermal space and water heating is usually supplemental to existing systems and reduces the use of the primary energy source used in the system.

Solar thermal space heating is cost prohibitive today and adds approximately $30,000 to the cost of construction for an average new single family detached home. Solar thermal domestic water heating at present costs about $8,000 for an average home and can be used as a supplement to the existing hot water tank to supply roughly half of the yearly water heating energy requirements.

Any solar energy usage results in GHG savings for that part of the load that it displaces. As a result, GHG production can be reduced by about 50 per cent.

The average household uses approximately 25 GJ/year for domestic water heating. If there was an annual reduction in gas usage of 12.5 GJ/year, that would reduce household greenhouse gas production by approximately 600 kilograms/year of CO2e.

We will provide incentives of $1,000 towards a solar thermal hot water system so long as natural gas is used to provide the balance of energy for the system. This will equate to incentives of $518 thousand for 2010 and $1 million for 2011 for a total of $1.5 million for the RRA period.

Ground Source Heat Pumps ("GSHP") - A GSHP uses the earth or ground water or both as the sources of heat in the winter, and as the "sink" for heat removed from the building in the summer. Heat is extracted from the earth with a liquid, such as ground water or an antifreeze solution, upgraded by a heat pump, and transferred to indoor air via a heat exchanger. During summer months, the process is reversed as heat is extracted from indoor air and transferred to the earth through the ground water or antifreeze solution.

GSHP systems are available for use with both forced-air and hydronic heating systems. They can also be designed and installed to provide heating only, heating with "passive" cooling, or heating with "active" cooling. Passive-cooling systems provide cooling by pumping cool water or antifreeze through the system without using the heat pump to assist the process.

GSHP systems are more costly than gas or electric systems and can add upwards of $10,000 to $20,000 to the cost for average new home construction. GSHP can be used as the primary source of energy to heat a building; however they do require a back-up source of energy such as a gas fired boiler.

The average household uses approximately 53 GJ/year for space heating. With a GSHP combined with a natural gas boiler for back-up there could be annual reduction in gas usage of 35 GJ/year per installation, which would reduce household greenhouse gas production by approximately 1.6 tonnes per year.

We will provide incentives of $1,000 towards the installation of GSHP pre-piping and provisions for the future installation of the heat exchanger. This will equate to incentives of $518 thousand for 2010 and $1 million for 2011 for a total of $1.5 million for the RRA period. To be eligible for incentives the installation must meet also meet the following criterion:

The GSHP must be backed up with a natural gas boiler for new construction and for retrofit installations. The GSHP system uses either a closed loop (i.e. under-ground piping) or an open loop (i.e. well, if the water source is suitable). The system equipment, design and installation meets CSA Standards

We believe that it is the utilities responsibility to continue and expand its energy efficiency and conservation programs available to customers. We believe that the programs detailed in these sections are in the interest of customers and should be approved.

b) Alternative Energy Solutions

The second part of TGI's strategy for meeting evolving customer needs and government policy is to pursue new alternatives to augment and enhance our core gas business. Natural gas will remain a foundational source of energy for the foreseeable future.[151] The pursuit of the new Tariff offerings

[151] Please see TGI's most recent Resource Plan, at www.terasengas.com

identified in this section for NGV compression and transportation service, as well as investment in biogas recovery, geothermal, solar thermal and district heating, is a prudent response to the challenges being faced by traditional natural gas service. We believe that it is in the best interest of both existing and new customers that TGI offer these alternative energy solutions, with the program, development and sales costs of these activities recovered as part of the revenue requirement.

The following sections report on TGI's specific opportunities that we intend to pursue, propose a regulatory model to assess each opportunity, and comment on other alternative energy solutions TGI intends to pursue in the future.

(1) NATURAL GAS VEHICLES ("NGV") RATE OFFERINGS

With the reduction of natural gas use as a result of energy policy, industrial, commercial and residential use, natural gas vehicles are one of the main areas where there is potential for volume growth. The growth of NGV benefits existing customers by adding natural gas customers with high load factors[152] to the TGI system. Government policy also supports NGV as a cleaner alternative to fuels like diesel, gasoline and propane. Natural Gas as an alternative is the cleanest burning fossil fuel as it has the fewest carbon molecules on the atom.

On June 8, 2009, TGI received BCUC Order No. G-65-09 which approved Rate Schedule 16 – Interruptible Liquefied Natural Gas Sales and Dispensing Service. To further support and grow the NGV market TGI proposes two new rate schedules:

1. Rate Schedule 6C – Natural Gas Compression and Refuelling Service
2. Rate Schedule 26 – Natural Gas Vehicle Transportation Service

These service offerings are targeted mainly at fleet customers that have return-to-home vehicle fleets, where refueling can occur at the end of each day. The Compression and Refueling Service contemplates that TGI will construct the necessary facilities for a fleet, and the customer would be charged a postage stamp rate of $5/GJ for compressed natural gas. The rate is designed to recover the cost of compression over a reasonable period of time, while ensuring that the service remains competitive with alternative fuel choices. Customers can combine compression service with a delivery service through either a sales or transportation Rate Schedule. The transportation service proposed under Rate Schedule 26 is the same delivery service as that currently provided under Rate Schedule 6, except that customers would have the option of purchasing the commodity from a marketer. TGI's proposal overcomes the potential

[152] Adding customers with a high load factor is advantageous as they increase the efficient use of the pipeline system therefore reducing costs to all other customers.

obstacle to adoption arising from the capital cost of compression and delivery facilities. Other potential hurdles to take-up exist, notably fleet conversion costs and availability of natural gas vehicles. We nonetheless believe that by offering compression and NGV transportation service, with the associated grants already available from Terasen Gas, customers will be more likely to embrace NGV as part of their fleet operations.

Below, we discuss the drivers behind this rate offering, the opportunity presented, followed by a discussion of how the proposed Rates were designed.

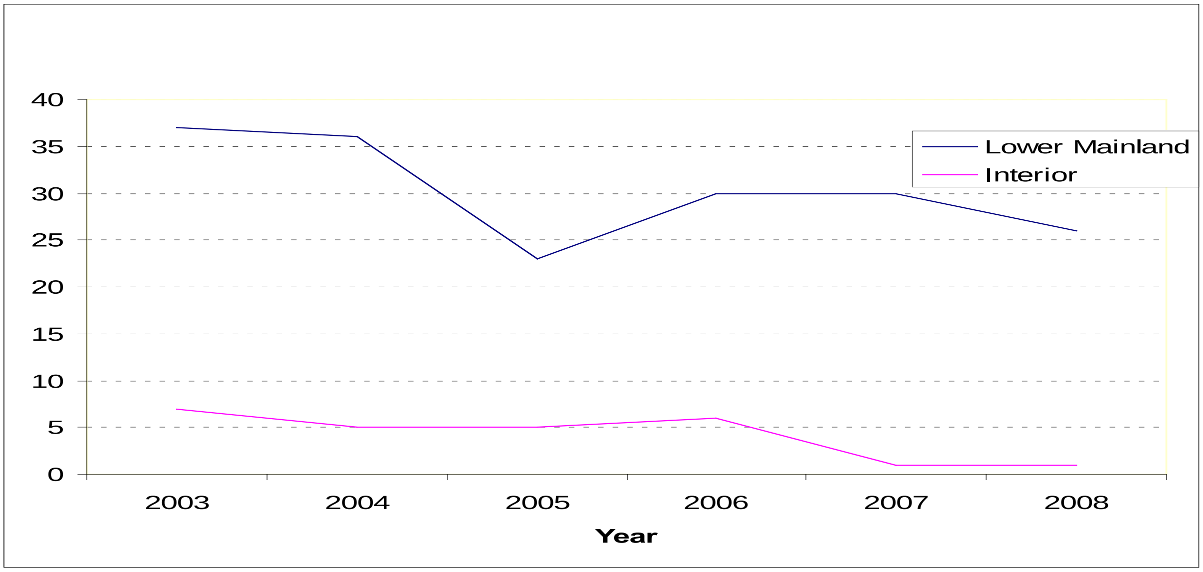
(a) Overcoming Market Obstacles

The number of Rate Schedule 6 – Natural Gas Vehicle Service customers has declined from 2003 to 2008. This decline is primarily due to the limited number of Original Equipment Manufacture ("OEM") vehicles, the limited presence of a third party compression provider, limited infrastructure to support re-fuelling, no concerted sales effort to educate customers about CNG as an option for fuelling, the cost of conversions and no clear policy direction encouraging lower emissions. Consumers in the BC market may still be cautious of using natural gas vehicles, due to the history behind natural gas vehicles in the 1990's. Some BC residents recall purchasing or converting vehicles only to experience vehicles that did not operate as proposed, and fueling stations that closed or were moved. In addition, North American auto makers stopped making the few OEM vehicles that were previously offered. However, with the change in policy, and a wider interest in using vehicles that are more efficient and reduce emissions, natural gas vehicles have an opportunity to make a resurgence. In addition, CNG technology has evolved significantly since early 2000's and this technology is just beginning to be showcased here in BC. IMW Inc now produces compression equipment in its Abbotsford manufacturing facility and Westport Innovations Inc. of Vancouver designs and in partnership with Cummins Westport Inc. manufactures heavy duty natural gas engines. Together, along with support from provincial energy policy, we believe we can deliver a made in BC solution to overcome the hurdles noted above.

(b) Decline in NGV Service Customers

Figure C-3-1 below presents the number customers served under Rate Schedule 6 – Natural Gas Vehicle Service between 2003 to 2008.

Figure C-3-1: Rate Schedule 6 Customers (2003 to 2008)



Gas Consumption (GJ's)						
For Year Ended	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
Lower Mainland	261,115	232,242	160,414	113,970	94,204	79,902
Interior	20,527	20,036	23,095	23,571	16,552	10,704
Total Consumption	281,642	252,278	183,508	137,540	110,756	90,606

Although a decline in Rate Schedule 6 customers and volume has been observed from 2003 to 2008 we see an opportunity for future growth in this market. Customers are seeking ways to reduce their energy costs and meet carbon reduction targets, heavy duty OEM vehicles are available locally through Westport Innovations Inc., compressors are manufactured locally by IMW industries, government policy aligns with an increase in NGV usage, and increased sales efforts by NGV parties are all contributing to increased interest in NGV usage. [153]

(c) Market Opportunity and Potential

The Wesport White Paper[154] discusses the economic and environmental benefits of NGVs. The paper notes that not only does using NGV reduce GHG emissions, they also can reduce the cost of fuel for

[153] Above figures do not include NGV volumes consumed under other rate schedules such as Rate Schedule 25. Currently, customers who do not wish to resell natural gas and who do not receive NGV grants may receive service under any other rate schedule for which they meet the applicability requirements. It is for this reason that we wish to provide a transportation option for customers who wish to resell gas and for whom also wish to receive NGV grants. Rate Schedule 26 will offer this alternative.

[154] See Appendix G-2 for a copy of Westport White Paper

customers. The paper further states that there are over 17,000 heavy duty trucks, 103,000 medium duty trucks and 1,400 transit buses in BC. We see this as an opportunity to increase natural gas load on our system, meet customer needs and align with government policy direction.

(i) Return-to-Home Fleets

The main drawbacks currently with NGV are lack of re-fuelling infrastructure and limited travel distance due to the need for compression tanks on the vehicle. We believe a bundled natural gas supply, options for transportation NGV service, and compression and refueling service will be more attractive to new and existing customers and promote the growth of the CNG market. The opportunity is greatest for fleet vehicle operators with "short haul, return to home" fleets. As noted in the Westport Paper, these include transit buses, and heavy and medium duty trucking fleets, and also school bus and forklift fleets.

All of these market segments offer opportunities for the transportation sector to use natural gas as a fuel source that is cleaner, cheaper, and is in great abundance in the Province. Additionally, these markets are also an ideal target market for biogas as a supply source, which would enable transportation customers to be net zero emitters. Further details of these market segments are presented in the Westport Paper and below.

(ii) School Buses

Many communities in the US (mostly in California) use natural gas buses to transport children to and from school. The greatest advantage of the natural gas bus to this segment is the "cleaner burning" nature of the fuel, as well as the fact that the buses are so quiet.

(iii) Forklifts

There are a significant number of industrial companies in the province that have anywhere from 10-100 forklifts on site running continually in a given day. As opposed to buses which must be OEM delivered vehicles, to provide natural gas vehicle service to a forklift, the propane forklift must simply be converted (a straightforward process costing approximately $3,500 CAD per vehicle). Compression is then provide on-site for refueling purposes. CNG has significant advantages over propane, namely air quality improvement in warehouses leading to healthier work conditions, and lower GHG emissions. In addition customers may see fuel cost savings when switching from propane to natural gas.

(iv) Compression and Refueling Service

Currently, natural gas compression and refueling service is available at 14 public stations in the Lower Mainland, in additional there are private stations owned by business and municipalities. In TGI's opinion, the main hindrance to new entrants into the commercial compression market is the up-front capital required. We believe that in order for the NGV market to grow, we must play a pivotal role by providing compression service to customers who do not wish to own and operate their own compression service. Below, we discuss the types of compression that TGI would make available under its proposed Compression Rate, and more detail about the derivation of the Rate.

(a) Types of Compression

There are two categories of compression and refueling equipment available, slow-fill (or time fill) and fast-fill. TGI would be in a position to offer either service.

The typical application for slow fill is a return to home fleet, such as delivery trucks of forklifts, where drivers connect the vehicles overnight to the fueling infrastructure. Fueling tends to take about 8-10 hours and vehicles are fully fueled by morning and ready for use. Fast-fill compression, as the name implies, fuels in a much faster time frame; although the speed of fueling requires a higher price tag, a greater reliance on "redundancy," and maintenance. The following table summarizes the two categories:

Table C-3-5: Summary of Slow Fill and Fast Fill

Slow Fill	Gas is compressed and dispensed slowly directly to vehicles' onboard storage tank. Lower cost station investment. Best for fleets that return to central lot and sit idle overnight or for extended periods.
Fast-fill	Similar to liquid fueling station, same fill rates and times. A MUST for public access. Also good for larger fleets where fueling turn-around time is short.

The type of refueling required on a specific site is dependent upon the individual customer's needs and as such differ greatly from installation to installation. Often there may be a combination of natural gas refueling options such as fast and slow fill depending on customers' operational requirements.

(b) Proposed Compression and Refueling Service Rate

TGI intends to purchase, own, install and operate the compression and refueling equipment necessary to provide compression service to customers. In addition the Company will also maintain the equipment either using internal resources or securing services from external service providers. We propose a postage stamp, volumetric charge of $5.00 per GJ for the compression and refueling service, which would be in addition to delivery and commodity charges. The volumetric charge creates an appropriate incentive in terms of conservation and demand side management. In addition, this rate structure is how vehicles are currently served with other fuels such as gasoline and diesel. TGI arrived at the $5.00 per GJ charge through a two-prong approach of economic alternative analysis and cost of service analysis. In order for compressed natural gas to be competitive, the bundled cost of natural gas compression, delivery and commodity must be significantly lower than the alternative fuel; that being gasoline, diesel or propane. Due to the incremental capital cost of a natural gas vehicle, a lower bundled charge for both natural gas and refueling service will allow for a payback period that, depending upon vehicle type and usage, can be anywhere from 1-10 years. If there is no payback, the only incentive for customers to use natural gas is reduced emissions; this alone is generally not enough to encourage a customer to use natural gas. Secondly, to be competitive, the rate must be one that is similar in structure to rates customers pay for other fuels. Gasoline, diesel and propane are sold using a strictly volumetric rate. As such a compression and refueling rate must not only be competitive but should also be volumetric in nature. When combined with the current delivery and commodity charge, bundled NGV service (Rate Schedule 6 charges plus the proposed compression and refueling charge) equals:

$0.59/Diesel Litre Equivalent ("DLE")
$0.37/Propane Litre Equivalent ("PLE")
$0.47/Gasoline Litre Equivalent ("GLE")

These rates are competitive with the present costs of propane, gasoline and diesel are shown in the table below:

Table C-3-6: MJ Ervin Pump Price Survey – Retail Vancouver Pump Price

Propane	Diesel	Gasoline
53.4/L	91.1/L	106.9/L

Below are three graphs showing the relative competitiveness if TGI had a $5.00/GJ compression and refueling rate (bundled with the delivery and commodity rates effective January 1 of each year) as compared to the retail rates for propane, gasoline and diesel:

Figure C-3-2: Propane vs. Natural Gas (PLE)

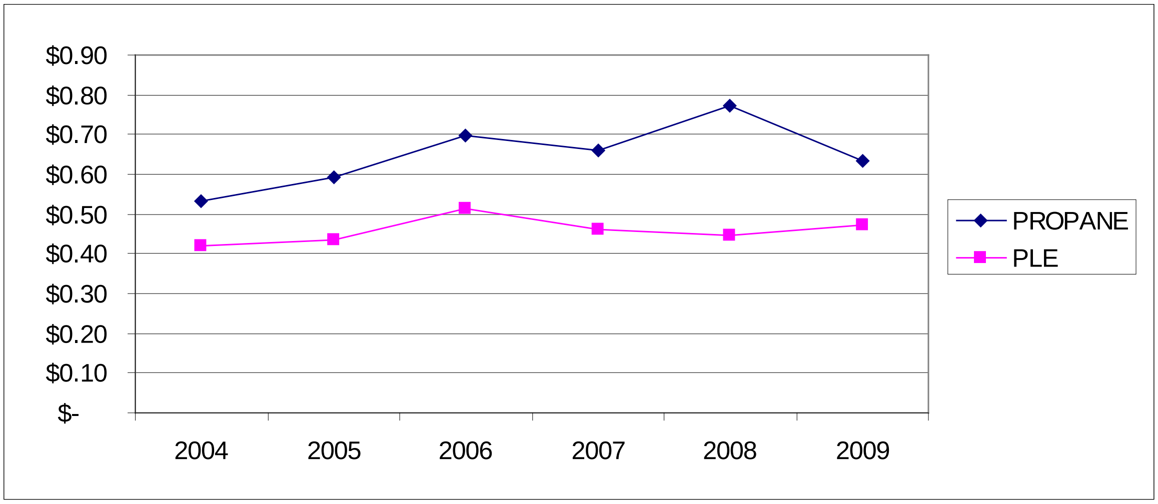


Figure C-3-3: Diesel vs. Natural Gas (DLE)

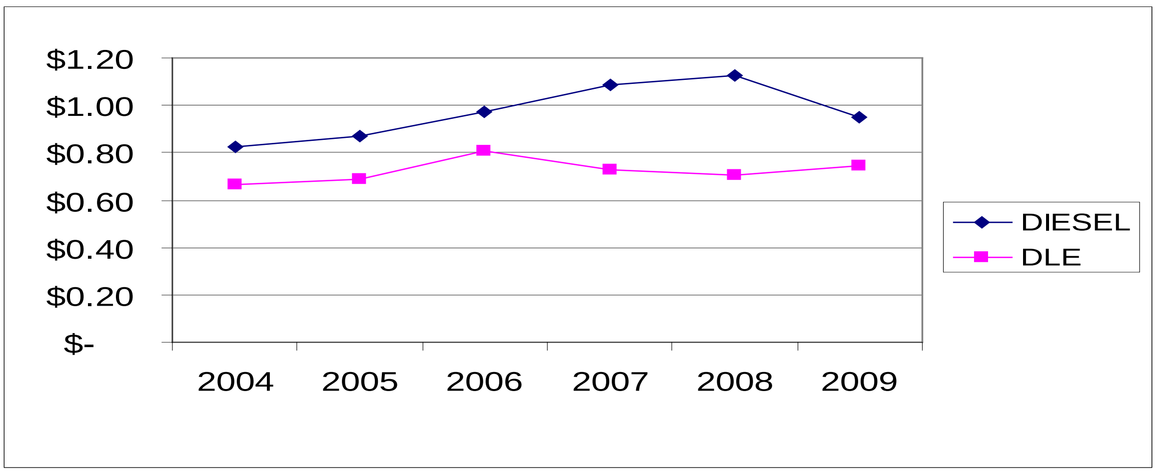
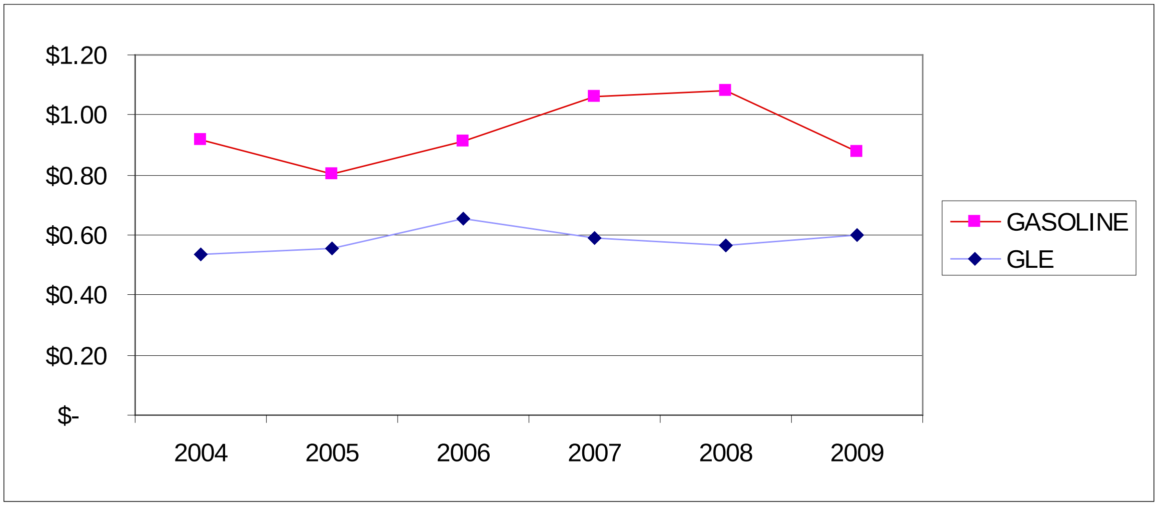


Figure C-3-4: Gasoline vs. Natural Gas (GLE)



The second prong of the approach to arriving at a postage stamp rate for the compression and refueling service is a cost of service ("COS") analysis. For the COS analysis, TGI assumed a 5-year scenario consisting of various costs (capital and O&M) and demand (vehicles and consumption). TGI arrived at the capital costs and demand forecasts by using its projected sales targets for compression service. The capital and operational costs were provided by compression equipment providers. Demand was based upon what we believe is a reasonable target for fleet vehicle additions. The analysis was based on matching the capital investment or the capital cost of the compressor equipment, along with the other COS components including O&M, depreciation, and taxes, with the short-term demand (5-year, the same time frame as a traditional MX Test) for Compression and Refueling Service. The result of the analysis was a compression and refueling rate of approximately $5.00 per GJ. The tables below outline the capital costs and resulting COS including the volume assumptions.

Table C-3-7: 5-Year Capital Additions Assumptions

	Year 1	Year 2	Year 3	Year 4	Year 5
Capital Additions ('000)	$ 238	$ 294	$ 399	$ 35	$ 873

Table C-3-8: Cost of Service Summary

NGV Station										
Cost of Service Summary ($Thousands)										
Calendar Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Nominal "000$	1	2	3	4	5	6	7	8	9	10
Equipment Options										
Total Operating & Maintenance	14	39	75	76	135	138	141	144	146	149
Depreciation	4	14	27	35	53	70	70	70	70	70
Income Tax	(7)	(19)	(29)	(29)	(41)	(48)	(31)	(17)	(7)	2
Property Tax	0	0	0	0	0	0	0	0	0	0
Debt Expense	5	17	32	41	61	80	77	74	71	68
Return on Equity	4	12	22	28	42	54	52	50	48	46
Total Annual Cost ('000$)	20	62	127	152	250	294	308	320	328	335
Annual Demand (GJ)	1,800	8,400	16,000	36,600	62,200	70,000	70,000	70,000	70,000	70,000
Annual Toll ($/GJ)	11.27	7.42	7.91	4.14	4.02	4.19	4.41	4.57	4.69	4.78
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
	11	12	13	14	15	16	17	18	19	20
Equipment Options (Continued)										
Total Operating & Maintenance	152	155	159	162	165	168	172	175	179	182
Depreciation	70	70	70	70	70	70	70	70	70	70
Income Tax	9	14	18	21	23	25	26	27	27	28
Property Tax	0	0	0	0	0	0	0	0	0	0
Debt Expense	65	61	58	55	52	49	46	43	40	37
Return on Equity	44	42	40	38	36	33	31	29	27	25
Total Annual Cost ('000$)	339	342	344	345	346	346	345	344	343	342
Annual Demand (GJ)	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000
Annual Toll ($/GJ)	4.84	4.89	4.92	4.93	4.94	4.94	4.93	4.92	4.90	4.88
Level Toll - 20 Years										
2009 - 2028, $/GJ $4.77										

A $5.00 per GJ compression and refueling rate will ensure that forecast revenues match or exceed the cost of service.

We believe the proposed compression and refueling rate is appropriate as the rate was derived using the best possible information on capital costs, usage rates, and O&M. In addition, the resultant rate will be competitive with diesel, propane and gasoline.

(v) Economic Test

For each application for Compression and Refueling Service, the Company proposes that the potential compression customer pass an economic test to assess the economic feasibility or profitability of the capital investment. In this case a compression customer would typically be a fleet operator on whose property the compression equipment would be located. An economic test would take into account the vehicles and associated expected volumes, and the revenue ($5.00/GJ) generated from those volumes. This would be compared against the costs for installation and operation of the compressor. The Company proposes to use a modified MX test, referred to in this Application as the Compression and Refueling Service ("CS") Test, which is described below. We believe this approach will ensure that existing customers are not subsidizing the Compression and Refueling Service, while at the same time ensuring that TGI is able to connect as many compression customers as possible. By adding new economic NGV customers to the TGI system, the existing system is used more efficiently and as a result the revenues from NGV delivery service will help to keep rates lower for all customers.

The CS Test, similar to the MX Test, is a twenty year discounted cash flow analysis which compares the present value ("PV") of cash inflows to the PV of the cash outflows from a proposed investment in compression and refueling equipment. The cash inflows used in the CS Test are the revenues from rates and fees paid by the customer or customers served by the compressor, as per the proposed Rate Schedule 6C, and do not include the Rate Schedule 6 delivery charges, commodity cost recovery charge or midstream cost recovery charge. The cash outflows are the estimated annual costs for the Company to install and operate the compression system in the first five years of the service including capital costs for materials and installation of the compressor and associated equipment, on-going operating and maintenance costs and upstream system improvement costs.

Again, similar to the MX Test, the CS Test is used to determine a PI that represents a ratio of the PV of expected revenues to the PV of expected costs. We propose to use CS Test parameters which are reflective of a compression and refueling service. The parameters are presented below:

Table C-3-9: CS Test Parameters

Parameter Name	TGI 2009 MX Test Parameters	Proposed CS Test Parameters	Comments for CS Test Parameters
Application Fee - New	$85	Case-specific	Not applicable if gas service received through Rate Schedule 6. Applicable to all other rate schedules to measure volume through compression equipment.
Application Fee - Existing	$25	N/A	Not applicable.
Change of Service Frequency	5	N/A	Not applicable.
Overhead Rate	32.0%	Case-specific	Based on cost of compression equipment.
CCA Class 1	6.0%	20.0%	NGV compression and fueling equiment are Class 8.
Project Life	20	20	Same
Discount Rate	4.20%	4.20%	Same
Fixed SI	N/A	N/A	Same. Not applicable.
Variable SI	$0.16	N/A	Not applicable. Included in MX Test for other rate schedules (i.e. Rate Schedule 6).
Income Tax Rate	30.0%	30.0%	Same
Income Tax Surcharge	N/A	N/A	Same. Not applicable.
Property Tax Rate	1.85%	N/A	Not applicable. Compression equipment similar to station.
Working Capital Rate	0.50%	0.50%	Same
Demand Charge	Rate dependant	N/A	Not applicable.
Fixed O&M	Rate dependant	Case-specific	Based on the model/size of compression equipment
Variable O&M	N/A	N/A	Same. Not applicable.
In Lieu Rate	Rate dependant	N/A	Not applicable. NGV revenues are exempt from property tax.
Fixed Margin	Rate dependant	N/A	Not applicable.
Variable Charge	Rate dependant	$ 5.00	Propose $5.00/GJ Compression Rate

The economic test will be based on the $5.00 per GJ compression and refueling rate presented above. Due to the small number of compressors expected in the early years of this service offering, we propose an individual PI of 1.0 rather than 0.8 used for individual main extensions. This will ensure that, based upon forecast consumption, new compression service customers will recover the costs associated with serving them. Therefore, if the PI is less than 1.0, the customer will be required to provide an upfront contribution in aid of installation as compensation for the revenue shortfall.

We believe the CS Test will ensure that existing customers are not harmed by customers under the Compression and Refueling Service, while at the same time ensuring that TGI is able to connect as many compression customers as possible.

(vi) Capital Additions and Revenue – Forecast and Treatment

Although the interest in this market has increased as a result of the BC Energy Policy and increased customer awareness of natural gas as a vehicle fuel, sales cycles are typically quite long. Customers must first be comfortable with the merits of natural gas vehicles and then they must then be prepared to either purchase OEM vehicles or convert existing vehicles. Once this commitment has been reached, only then can TGI contract to install compression service. As such, TGI sees modest growth over the two year period of the revenue requirement. Sales targets for capital investment, customers and volume are shown below.

Table C-3-10: Sales Targets for Capital Investment, Customers and Volume

2010					
Vehicle	**Capital Investment Potential**	**# of Vehicles**	**Annual GJ**	**1/2 Year GJ Volume**	**TOTAL GJ's**
School Bus	125,000	2	300	150	300
Fork Lift	100,000	10	200	100	1,000
Garbage hauler	250,000	2	1,000	500	1,000
P/U (Mixed Use)	150,000	5	200	100	500
	$ 625,000				**2,800**
2011					
Vehicle	**Capital Investment Potential**	**# of Vehicles**	**GJ**	**1/2 Year GJ Volume**	**TOTAL GJ's**
School Bus	250,000	4	300	150	600
Fork Lift	300,000	60	200	100	6,000
Garbage hauler	450,000	4	1,000	500	2,000
P/U (Mixed Use)	500,000	10	200	100	1,000
	$ 1,500,000				**9,600**

Note that the forecast capital additions are based on an estimate of the success of our sales efforts.

As TGI attaches compression customers we will incur ongoing O&M costs for the repair and maintenance of the compression equipment. These O&M costs are dependent upon not only the quantity of capital installed but also the type of equipment installed to serve specific customers. The O&M costs incurred in respect of each customer are appropriately accounted for as part of the CS Test.

As the sales cycle is long, the nature of customer acquisition uncertain, the timeline of capital expenditures undetermined and associated O&M expenses unknown, TGI is forecasting zero capital additions, O&M expenditures and revenues in this area for the purpose of the RRA. As such, TGI believes it is prudent and therefore proposes that revenues, ongoing O&M and capital attributed to additions in 2010/11 be recorded in a non-rate base deferral account for the period of the RRA. In this manner, existing customers' rates will not be impacted in 2010 and 2011 by capital and O&M expenditures, and associated revenues that are too uncertain to forecast at this time.

(vii) Approvals Sought

We request Commission approvals of Rate Schedule 6C - Natural Gas Compression and Refueling Service and Rate Schedule 26 – Natural Gas Vehicle Transportation Service which are included as Appendix J. If Rate Schedule 6C - Compression and Refueling Service (Appendix J-6) is approved, we also seek approval to cancel Rate Schedule 6A – General Service – Vehicle Refueling Service (Appendix J-5), as it will become redundant. We request approval of the deferral treatment of compression equipment costs and expenses. The Transportation Service and the Compression and Refueling Service, as proposed in this Section of the RRA, complements the existing NGV service and results in a comprehensive natural gas fuel service across the value chain which offers customers solutions in managing transportation costs and reducing GHG emissions. The rate proposals also benefit existing customers through the more efficient use of our delivery infrastructure.

As indicated above, we are seeking approval to record in a deferral account the revenues and O&M and capital expenditures associated with NGV and the service provided. In this manner, existing customers will not pay for capital costs, and associated revenues that are uncertain over the RRA Period.

(d) Biogas

The development of biogas upgrading and recovery projects represents an opportunity to recover useful energy from waste, to displace other consumption of fossil fuels such as diesel, to complement the use of natural gas, and to reduce greenhouse gas emissions. Biogas upgrading was identified in TGI's 2008 Resource Plan as a potential new supply resource for the Company to assist in meeting the goals of the

2007 BC Energy Plan and the legislated "government's energy objectives".[155] Biogas represents an energy alternative that will be the right energy source for some customers, frequently in conjunction with natural gas. Investment in the development of a viable biomethane supply, in tandem with the development of rate offerings intended to recover the higher cost of biomethane from the consumers of that product, is an important element of our plan to augment our core business to provide a broad range of energy solutions to customers and communities.

Over the two-year RRA period, we propose to expand the development of biogas capture and upgrading in BC in a Pilot Phase of limited scope. In particular, TGI seeks approval to proceed with biogas upgrading projects and biogas/biomethane purchase agreements during the 2-year RRA period, provided that two conditions have been satisfied:

- the combined costs of upgraded biomethane (i.e., total raw biogas and upgrading costs) from each project are below a threshold price of $15 per GJ; and
- the combined annual output of the biogas projects on stream is less than 0.5 PJ.

The costs of biogas and upgrading will be separately tracked and accounted for. TGI is also requesting approval to recover the costs of biogas and upgrading, during this two-year period, through TGI's Midstream Cost Reconciliation Account. We also discuss our intention to develop a targeted marketing offering to sell biomethane or "green" gas to interested customers at a premium relative to traditional natural gas. Each of these components is discussed in further detail below.

(i) Lions Gate Waste Water Treatment Plant Project

On April 14, 2009 TGI applied to the Commission in respect of its first biogas upgrading demonstration project, to be installed at the Lions Gate Waste Water Treatment Plant ("Lions Gate WWTP Project"). TGI requested the following:

- a CPCN for the biogas upgrading facilities at the Lions Gate WWTP which TGI would own and operate,
- approval of an energy supply contract with Metro Vancouver for raw biogas; and
- approval of the proposed regulatory treatment of the overall cost of the upgraded biogas (or biomethane) in which TGI proposed to track biogas and upgrading costs separately and recover the overall biomethane costs through the Company's Midstream Cost Reconciliation Account.

[155] See Appendix C-8 for a copy of the Bill 15 – 2008 Utilities Commission Act Amendment

In mid-May 2009 Metro Vancouver, the owner and operator of the Lions Gate WWTP, withdrew from the project for reasons that are specific to that facility. On June 19, 2009 TGI will file a letter with the Commission regarding the status of the Lions Gate WWTP, and at this time is contemplating withdrawing the application. However, the underlying drivers for the Lions Gate WWTP Project have not changed. Those drivers have, in general terms, been highlighted in Part III, Section A, Tab 1. The pursuit of biogas capture initiatives is an appropriate response to evolving policy and customer expectations. There is a need to pursue biogas capture in the context of a relatively small-scale pilot program. We can learn from our experience with these projects. These drivers are discussed further below.

(ii) Biogas Policy and Regulatory Context

The Commission must consider the "Government's Energy Objectives" in its assessment of applications of various types. To support these objectives the Commission must encourage public utilities to reduce GHG emissions and to employ innovative energy technologies that promote the use of clean or renewable sources of energy[156]. Biogas upgrading and recovery is consistent with the development of alternative energy sources and the development of bioenergy projects as outlined in the 2007 BC Energy Plan and the 2008 BC Bioenergy Strategy ("Bioenergy Strategy"). The Bioenergy Strategy states that "Government and its partners will collaborate to develop B.C. bioenergy projects utilizing energy from wood waste, agriculture, renewable fuels and municipal waste"[157].

(iii) Development of Biogas Upgrading Projects during the RRA considered a Pilot Phase

We intend to develop biogas upgrading projects for the two-year forecast period and to consider the projects, at least initially, as a Pilot Phase of biomethane supply development. Development of biogas recovery and upgrading projects during the two-year RRA period will provide the Province, Terasen Gas and other parties with valuable knowledge and experience to grow this renewable energy resource in the future. The economic model for assessing the appropriate rate for these projects and associated streamlined regulatory process proposed later in this Biogas section will facilitate our development of biogas projects, and lay the foundation for the introduction of a "green" gas offering to be sold to specific customers that wish to purchase carbon-neutral gas at a premium to traditional natural gas.

[156] Biogas upgrading was identified in TGI's 2008 Resource Plan as a potential new supply resource for the Company to assist in meeting the goals of the 2007 BC Energy Plan and the legislated "government's energy objectives". We stated our intention to pursue biogas developments in Item 7 of the Action Plan.[156] The Commission accepted the 2008 Resource Plan on December 15, 2008 by Order No. G-194-08. The Commission's acceptance was unqualified with respect to Action Plan Item See excerpt from the "Government's Energy Objectives" definition in the *UCA* in the Government-Driven Change section above (Section b) (2))

[157] BC Bioenergy Strategy – Growing our Natural Energy Advantage, 2008, p.8.

We intend to pursue the development of new biogas projects with purpose, but our plans must be flexible enough to recognize that this is a new area of business that involves many parties and interests, and that there are many processes to be developed and lessons to be learned. The primary purpose of the Pilot Phase is to validate the technical feasibility of upgrading biogas from various sources of raw biogas including wastewater treatment plants, agriculture applications and landfills to pipeline grade biomethane. We consider the development of new biomethane supply projects from differing raw biogas supply sources to be important in the overall understanding of how biomethane will function as a supply source. TGI will gain experience with the injection of biomethane into its gas distribution system. The lessons learned during the proposed Pilot Phase will be used to improve the processes in the development of other biogas upgrading projects as well as to assess the next steps in TGI biogas initiatives. The Pilot Phase will also assist us in understanding the cost parameters of biogas projects and what might be expected in terms of economies of scale from larger projects. TGI is in a key position to provide leadership and funding to advance these types of projects with the hope that biogas developments will be able, in the longer term, to deliver sustainable environmental benefits at a reasonable cost through a "green" offering.

We also intend during the two-year RRA period to develop a "green" commodity sales option using biomethane to be marketed to specific customers at premium prices. While we intend to proceed as quickly as possible with the development of a targeted biomethane sales offering, it is premature at this point to expect that an offering of this nature can be fully developed and brought forward before the end of 2009. With the cancellation of the Lions Gate WWTP biomethane project TGI does not have any projects as of the time of preparing the RRA Application that are certain to be producing pipeline-grade biomethane before the end of 2009 (although there are several projects that may come to a more advanced stage of development in the next several months). As such it is unlikely that we will have had one full annual cycle of experience with biogas upgrading at any one site until the end of 2010 or later. We will not have experience with biogas upgrading from multiple sites and various supply sources, such as other waste water treatment plants, landfills, or agricultural contexts until after 2010.

Bearing this in mind, during the RRA period we intend to work in parallel on biomethane supply development and the structuring of a targeted market offering of "green" gas.

(iv) Parallel Development of "Green" Offering

The evolution of the biomethane initiative from being simply a different supply source to a targeted market offering will be brought forward to the Commission in a future application, likely during the RRA period. It is our intention, however, that the "green" gas offering sold to customers would recover all the costs of acquiring the "green" gas.

It is important that the pilot phase proceed at this time, in anticipation of the development of a "green" gas offering. The reasons for that are, in essence:

- we require a greater understanding of the full cycle of upgrading and injection of biomethane into our system and this must take place prior to a "green" gas offering, and
- we must also analyze the types of supply to be included in the green offering as well as many customer sales related issues.

The following discussion provides some background on the issues that will be considered from both the supply-related and demand-related perspectives.

From the supply perspective the types of supply that will be included in the green gas portfolio must be resolved. For instance the portfolio may include only the supply from biomethane projects or it may also include traditional natural gas which has been made carbon-neutral in effect by the purchase of recognized offsets or other means. If traditional natural gas with purchased offsets is to be included in the green gas supply portfolio it could be used as a balancing resource to match green gas supply and demand, or it might constitute a portion of the green gas supply portfolio over and above the amount needed as a balancing resource. We also intend to investigate and review the option of acquiring offsets for natural gas and the resolution of any barriers to including, if warranted, natural gas with offsets as a portion of the green portfolio. An example of an issue for resolution in this area is whether it will be possible to obtain an exemption from the carbon tax for natural gas with acquired offsets.

We also intend to address the numerous issues from the customer demand or sales perspective including the following:

- An assessment of market interest in a green gas offering;
- Determination of the nature of the initial offering:
    - A staged offering for particular rate classes or a broader offering;
    - Sell available green supply to interested customers on a first-come first-served basis until the supply is exhausted or develop natural gas / green gas blends to sell to a broader customer base;
- The development of terms and conditions of service of the offering; and

- Determination of rates for the offering, a rate adjustment methodology and frequency of rate changes.

The parallel work on acquiring and gaining experience with biogas supply, and the assessment of customer interest and demand for a green product offering will require a flexible and iterative process in arriving at the final product offering. For instance, having a larger-volume and more diverse portfolio of green gas will influence how broadly the offering can be made available to different customer segments. The types and numbers of customers interested in a green gas product and the amount they are willing to pay will also have a bearing on the nature of the offering. Once complete, it is our intent that the "green" gas offering would be sold to customers such that the price paid for the "green" gas would recover all the costs of acquiring the "green" gas.

(v) Evaluation of Biogas Projects

TGI believes that it is in the interests of all stakeholders to put in place a mechanism to streamline the evaluation and regulatory review of biogas projects as they arise.

The energy supply agreement, whether for raw biogas or upgraded biomethane, must be approved pursuant to section 71 of the UCA. TGI would need approval for the proposed recovery of the biomethane costs of service (through the Midstream Cost Reconciliation Account in the Pilot Phase) pursuant to Sections 59-61 of the UCA. In the case of the Lions Gate WWTF Project, the regulatory requirements meant a filing that was large in relation to size of the project in dollar terms. The requested process for the Application involved a workshop, information requests, and argument.

We are proposing a review mechanism for biogas projects that streamlines the Commission approval process for individual biomethane supply projects rather than having to go through a full review and justification process. The proposed process would involve the following steps:

- TGI performs an economic analysis, the elements of which are discussed below, to determine whether a project falls within the Commission's pre-established parameters;
- TGI submits the gas supply contract to the Commission for approval, together with documentation to demonstrate that:
  - the overall project costs are less than $15/GJ; and
  - the cumulative annual biomethane volumes from all active projects remain below the proposed volume cap on the Pilot Phase of 0.5 PJ per year.

Otherwise, TGI would apply under the normal regulatory process for the requisite approvals. As most of these projects are anticipated to be below the $20 million proposed threshold for a CPCN, we would still be seeking approval of the energy supply contract.

The proposed biomethane project review process is meant to accommodate the variety of possible supply sources, differences in potential supply locations and variations in ownership arrangements. The potential biogas supply sources include waste water treatment plants, landfills, agricultural wastes and urban food and green waste management. Biomethane supply locations will vary in terms of whether they are situated in urban or rural settings and in terms of their proximity to the TGI system. The system capabilities at a proposed biomethane receipt point will also affect the viability of a particular project.

Finally, there are two possible ownership arrangements anticipated for the biomethane supply agreements. The proposed mechanism will accommodate both models. In the first ownership arrangement a third party will own and operate the raw biogas gathering and generation facilities, and TGI will own and operate the biogas upgrading facilities. In the second ownership arrangement a third party (or parties) will own and operate all facilities, including the upgrading equipment, involved in creating pipeline-grade biomethane. In the first arrangement TGI would have a raw biogas supply agreement with the third party. In the second arrangement TGI would have a supply agreement with the third party for upgraded pipeline-quality biomethane.

The following components will be considered in a biomethane project evaluation:

1. The costs associated with the biogas supply agreement whether a raw biogas agreement or upgraded biomethane agreement, yielding a cost per GJ of raw biogas or upgraded biomethane
2. The rate base and cost of service of TGI-owned upgrading facilities
3. The rate base and cost of service of the interconnection costs to the TGI system. (If interconnection of the biomethane supply source allows for the connection of new customers that would otherwise not be served with gas a credit would be netted against the interconnection costs for this new revenue source.)
4. The rate base offset and cost of service reduction of customer or government contributions (i.e. ICE funding).

(vi) Economic Analysis

TGI is proposing that a cost of service approach be taken to evaluate the economics of individual biogas projects. The cost of service evaluation would include costs and expenses in TGI's cost of service for the facilities, equipment and raw biogas procurement required to produce pipeline quality gas and inject it into the TGI system, including operating and maintenance expenses, debt interest, return on equity, depreciation expense and taxes. The cost of service and expected production volume will ensure that the unit cost for the project of producing pipeline quality gas does not exceed the maximum price payable for biomethane. In cases where TGI is purchasing upgraded biomethane from a third party without investments in upgrading facilities the analysis to determine whether the project was below the maximum price threshold will be based on the price paid for the updraded biomethane. There would be no need to determine a cost of service for upgrading costs. For projects undertaken before the proposed green gas sales offering comes into effect the unit cost of biomethane from a project must be below an established threshold in order for the project to proceed[158]. The basis for the proposed $/GJ threshold is discussed below in Section (vi) (b) - Maximum Price per GJ for Biomethane.

The table below illustrates a sample COS calculation for biomethane. The elements included in the table are the components of the cost of service for a biogas upgrading project including raw biogas purchase costs and component costs of upgrading, as well as the volumes of upgraded biomethane, the carbon tax savings and an overall unit cost for biomethane by year. The levelized average unit cost for upgraded biomethane from a project will be used to assess whether the project is below the $/GJ threshold.

Table C-3-11: Sample Biogas Cost of Service Calculation

	Year 1	Year 2	Year 3	Year 4	Year 5
Operating & Maintenance	50	51	52	53	54
Cost of Raw Biogas	175	175	175	175	175
Depreciation	91	91	91	91	91
Income Tax	28	28	28	28	27
Property Tax	0	0	0	0	0
Debt Expense	18	14	10	6	2
Return on Equity	12	9	7	4	1
Total Cost before Carbon Tax Savings('000$)	374	368	362	356	350
Upgraded Biogas Production sent to Terasen (GJ)	35,000	35,000	35,000	35,000	35,000
Biogas Avg Cost before Carbon Tax Savings ($/GJ)	10.68	10.52	10.35	10.18	10.01
Carbon Tax Savings	(52)	(52)	(52)	(52)	(52)
Total Cost Net Carbon Tax Savings('000$)	322	316	310	304	298
Biogas Avg Cost Net Carbon Tax Savings ($/GJ)	9.19	9.03	8.86	8.69	8.52

158 After the green gas sales offering comes into effect (and any necessary transition period) it is expected that customers that choose that program will be paying for the costs of the green gas, although there are many possibilities for how such a program might be implemented.

(vii) Ownership of Upgrading Facilities and Gas Supply Contracts

As discussed above, biogas projects will include energy supply agreements for either raw biogas or upgraded biomethane. In some cases project proponents may want to invest only in the raw biogas generation or gathering facilities. In these cases a raw biogas agreement will be required and TGI will invest in the upgrading facilities needed to bring the raw biogas up to acceptable quality standards. In other cases project proponents may wish to do all of the investment in biogas generation and upgrading facilities necessary to produce pipeline quality biomethane. In these cases a gas supply agreement will be required. Both of these ownership structures are necessary to advance the development of the biogas industry.

In instances where TGI has concerns over the long-term viability of a project or the financial capabilities of a raw biogas producer the Company may not be interested in owning and operating the biogas upgrading equipment. In such circumstances TGI would enter into a gas supply agreement with the biogas producer for pipeline-quality gas. TGI would still own and manage the interconnection facilities including the metering and gas quality monitoring equipment. The gas supply agreements would be filed with the Commission pursuant to Section 71 of the UCA. This approach would minimize risk to TGI and its ratepayers while still providing system access to biogas suppliers to help continue to grow the biogas industry in BC through the production of renewable biomethane.

(viii) Evaluation Criteria

(a) Maximum Quantity of Biomethane

TGI proposes a 2010/2011 Pilot Phase with an allowed volume of biogas purchased or produced under the Pilot Phase of 0.5 petajoules (500,000 GJ). Through TGI's Biogas Request for Expressions of Interest ("RFEOI") process, the Company received nine submissions from a variety of raw biogas producers with potential biomethane volume in excess of 750,000 gigajoules. In addition to the RFEOI proponents TGI is also working with a biogas producer in the Fraser Valley who plans to supply 100,000 gigajoules per year to TGI. However, it is unlikely that all of these projects can be developed and producing biomethane (or that all are viable) within the two-year timeframe of the RRA. Therefore, the Company believes that a half of a petajoule of biomethane annually is a reasonable volume limit for the Pilot Phase. We will also apply to the Commission to move out of the Pilot Phase before reaching the 0.5 PJ annual volume threshold if a targeted "green" gas market offering is adequately developed and is ready for implementation.

To effectively evaluate the biogas initiative during the Pilot Phase, TGI believes that some diversity of biomethane supply is needed. A diverse portfolio, including multiple biogas supply types (i.e. waste water treatment plants, landfills, etc.) and a number of supply points will provide the Company with a stronger understanding of the operating characteristics of biogas producing and upgrading facilities, the seasonal production rates and system integration issues. The development of multiple projects will also benefit the company with a better understanding of the costs associated with building and operating various sized facilities.

(b) Maximum Price per GJ for Biomethane

TGI is proposing a maximum price of $15 / GJ of biomethane. Since biomethane is a new energy supply source there are no available external pricing benchmarks specific to biomethane that assist in setting a threshold price or cost. TGI believes that the price of new BC-based electricity supply, a competing energy source in the province, provides an appropriate reference point for biomethane pricing. The BC Hydro RIB Step 2 rate is an appropriate initial reference point for biomethane pricing since it has been established by reference to the cost of new electricity supply in the province. By Commission Order No. G-124-08, the Commission instructed BC Hydro to establish the RIB Step 2 rate at BC Hydro's cost of new supply at the plant gate, grossed up for losses[159]. Therefore, the RIB Step 2 rate is linked to BC Hydro's cost of new clean electricity supply[160] and is therefore an appropriate price cap for biomethane (after adjusting for thermal efficiency and allowances for TGI distribution costs) for use in the in the economic analysis in the Pilot Stage. In other words, the RIB Step 2 Rate can be used as a proxy starting point for the competitive cost of new thermal energy supply. It is also the electricity rate that many residential customers will pay for space heating in the winter months when their electricity usage is high, and is therefore an alternative heating option to biomethane.

Using the RIB Step 2 rate as a reference point for the Biomethane Electric Equivalent Calculation:

Apr. 1, 2009 RIB Step 2 rate	$0.0827 / kWh
Equivalent gas rate @ 90 per cent efficiency	$20.68 / GJ
Less:	
Terasen Basic Charge (R1 @ 80 GJs annual use)	(1.80/ GJ)
Terasen delivery charge	(2.85 / GJ)
Terasen midstream charge	(1.02 / GJ)

159 The results of the 2006 Clean Power Call were found to be representative of the cost of new supply for BC Hydro.

160 The RIB Decision is not prescriptive as to how the Step 2 rate will be adjusted when a change to the cost of new supply occurs, such as after new electricity purchase agreements are awarded out of a Call for Power process. As such, changes to the RIB Step 2 rate may lag relative to changes in the cost of new electricity supply but the RIB Step 2 rate is still a readily available price reference point and representative of a rate being paid for an alternative source of energy.

Net amount available for biogas charge $15.01 / GJ

The combination of the $15/GJ[161] cost on biomethane and the annual volume cap of 0.5 PJ limits the impact on customers of adding new biomethane supply resources under the proposed regulatory review process during the 2010/2011 RRA period to a modest amount. The upper limit on the MCRA impact of adding half a petajoule of biomethane at the maximum price of $15 / GJ would be an additional $4.14 million[162] as a result of replacing gas purchases at Sumas Forward prices with biomethane. An increase of $4.14 million in the forecast 2010 MCRA costs of $134 million would result in an expected increase of $0.038 per Gigajoule to the MCRA Cost. The actual impact is likely to be lower than this since it is unlikely that the 0.5 PJ volume cap will be achieved.

(c) Carbon Tax

The evaluation of the price per gigajoule of biogas will be performed on a net of carbon tax basis. Biomethane is exempt from the BC Carbon Tax. The Carbon Tax Act contains the following definition of "fuel" for the purposes of determining the carbon tax:

> **"fuel"** means a substance set out in column 2 of the Table in Schedule 1 but does not include
> (a) ethanol or methanol produced from biomass,
> (b) biodiesel and other biofuels, and
> (c) methane produced by waste in a landfill;

(d) Financial Treatment

The financial treatment proposed for the Pilot Phase provides a clear basis for the separate tracking and identification of the costs of biomethane development and procurement.

The Company's investment in biogas upgrading equipment during the Pilot Phase will be tracked in a separate asset account. Further, operating and maintenance costs and any other costs pertaining to the acquisition and upgrading of biogas to suitable quality for injection into the TGI system will be recorded in separate accounts. The separate tracking of biomethane costs will enable an overall calculation of the cost of service and average unit cost of biomethane. The components of the overall biomethane costs will be as follows:

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[161] Note - $15/GJ for Biomethane would equal $0.48/ GLE and $0.6 /DLE if used for vehicle fuel. With compression and delivery (Rate Schedule 6 delivery cost) cost per equivalent litre of gasoline would equal $0.76 and cost for diesel litre equivalent would equal $0.95.

[162] Biogas Unit Cost ($15/GJ) – Sumas Forward Price ($6.72/GJ) = Net unit cost ($6.28) x 500,000 GJ

TGI capital costs of biogas upgrading equipment to be recorded in the appropriate Products Extraction Plant accounts (Accounts 420 - 429).

Operating and maintenance costs, depreciation expense and any property taxes related to biogas upgrading and connecting facilities will be recorded in appropriate accounts corresponding to the asset accounts.

Biogas and biomethane purchase costs will be recorded in separate commodity accounts.

All of the separately-tracked costs for biogas upgrading will be used to determine an overall cost of service. The elements of the cost of service determination are described below:

- Return on the biogas rate base will be determined in the normal fashion using the approved TGI capital structure, debt rates and return on equity. Any future approved changes to TGI's capital structure and return on equity will be reflected in the return on rate base of the biogas upgrading assets in service.
- Depreciation expense for the Terasen-owned upgrading facilities will be based on a 6.67 per cent depreciation rate[163]. The 6.67 per cent depreciation rate is consistent with the expected service life of the upgrading equipment which is in the range of 15 to 20 years.
- Income taxes will be determined in the same fashion as with other TGI filings. The effects of depreciation expense and capital cost allowance on the income tax calculation will be based on the specific depreciation rates and capital cost allowance classes for the Terasen-owned biogas upgrading facilities.
- Operating and maintenance expenses will include electrical power, measurement and monitoring of the biogas flows and quality, replacement of consumable media, telecommunications costs, equipment maintenance and general maintenance around the facilities. Property taxes for the biogas upgrading facilities are not expected to be material but will be included in the biomethane cost of service to the extent that any incremental property taxes are incurred.
- The purchase costs for raw biogas or upgraded biomethane will also be included in the overall cost of service for biomethane.

[163] The depreciation rate may be increased in the case of agreements with terms that are shorter than 15 years.

- The upgraded biomethane volumes injected into the TGI system will be exempt from the BC Carbon Tax. The benefit of the carbon tax exemption will be netted against the overall cost of service of the upgraded biomethane.

As an initial approach to dealing with the biomethane costs as commodity costs, TGI proposes to transfer the overall biomethane costs of service and volumes into the MCRA on a monthly basis. The Company proposes to use the MCRA as the means to flow biomethane costs through to customers for the duration of the Pilot Phase. The costs and volumes associated with the biomethane from the Pilot Phase would therefore be factored into the annual MCRA flowthrough process.

The main reasons for flowing biomethane costs and volumes through the MCRA are discussed below. The half petajoule maximum of biomethane under Pilot Phase represents less than 0.5 per cent of the overall MCRA purchases and will have only a small impact on the Midstream Cost Recovery Rate. There are many issues to understand and gain experience with during this Pilot Phase. For instance, it is expected that the load profile of upgraded biomethane coming from biogas production facilities into the TGI system will be fairly steady throughout the year but this is not known with certainty. The frequency of outages, the magnitude of process fluctuations and variations are all potential sources of variations in the amounts that will ultimately be received into the TGI distribution system. Further, the receipt point of biomethane on the TGI distribution system means that it would not be suitable to treat this supply in the same manner as the baseload supply of marketers or TGI. Commodity volumes provided by marketers or which flow through the CCRA are 100 per cent firm baseload supply that must be delivered in certain proportions at the Station 2, AECO and Sumas hubs. The biomethane volumes from any projects completed during the RRA period will differ in that they will be, in effect, interruptible supply.

(e) Integrated Energy Solutions: Geo-exchange, Solar Thermal, and District Energy Systems

(i) Introduction

Natural gas service will continue to form the basis of our core business, however we will complement this core business with integrated and alternative energy to permit us to better meet the needs of customers and communities. For the purpose of this application, integrated and alternative energies include geo-exchange, solar thermal and District Energy systems. We view each of these alternative energy technologies as complementary to, or extensions of, the Terasen Gas energy system as these systems more often than not require natural gas as part of the energy solution. Customers, from developers to government to individual customers, are seeking to reduce emissions, lower energy usage and reduce long run costs.

To facilitate an effective assessment of potential alternative energy investments, Terasen Gas has developed an economic assessment test for determining the rate payable by a customer(s) served by an investment in alternative energy. This test, for which TGI is seeking approval, is described later in this section. The effect of the approval of this test will be to permit TGI to use a set of predetermined, Commission-approved criteria in arriving at a customer rate, which will then be included in a contract between TGI and the customer and filed with the Commission. This model will reduce project development time and therefore reduce uncertainty for customers while also supporting the objectives of provincial energy policy. We believe it is in the best interest of existing and new customers that TGI provide both gas and alternative energy solutions. As such we believe that the requests set forth in this section should be approved to facilitate that development.

(ii) Geo-exchange, Solar-thermal and District Energy Systems Description

Geo-exchange and solar thermal energy systems are similar in that they utilize thermal heating and cooling energy from the environment to replace or supplement traditional gas or electrically fired space and water heating systems. District energy systems use a variety of heating sources, including traditional heating sources such as gas and non traditional sources like sewage heat recovery, to deliver heating and cooling to the end use customer. TGI believes that it is in the interest of our existing and future customers for TGI to offer a full range of these types of efficient, low carbon intensity energy alternatives, and we intend to pursue these opportunities.

(a) Geo-exchange

Geo-exchange systems; also referred to as geo-thermal systems, earth exchange systems or ground and water source heat pumps, utilize the heat energy contained in near surface layers of the earth, ground water and surface water. A subsurface piping system contains a liquid that absorbs heat from the surrounding material and delivers it to a central heat exchanger[164]. High efficiency heat pumps convert this energy into hot water or steam contained in a separate piping system that can then deliver the heat energy to where it is required for space heating and hot water uses. Centralized equipment is usually contained within a specifically designed mechanical room that serves the entire development. The heat exchanger is reversed to provide space cooling, removing heat from the building(s) and returning it to the subsurface substrate.

[164] Typically geo-exchange systems are designed to provide 50-80% of the heat with the remaining heat provided for by a gas boiler

(b) Solar-thermal

Solar-thermal water heating systems, also called solar hybrid water heating systems, are more typically used to supplement traditional gas and electric energy systems that supply DHW, improving the efficiency and lowering the carbon intensity of the traditional systems. A system of solar collection tubes and piping capture heat energy from the sun's rays and deliver it to a central heat exchanger, where it is converted to DHW and distributed in a manner similar to that described above for geo-exchange systems. The solar collection tubes are located outside the building or buildings, typically on the roof, while centralized equipment is again housed in a specifically designed mechanical room.

Both geo-exchange and solar-thermal energy systems can be designed in combination with other traditional piped energy systems and metering technologies already a part of TGI's regulated service offerings. TGI's expertise with piped energy infrastructure, metering equipment and customer services combined with the current environmental and social values of customers make these systems an obvious evolution of TGI's business.

(c) District Energy

District energy systems ("DES") employ a range of energy technologies and sources to deliver piped heating (hot water) and/or cooling (ambient or chilled water) to multiple buildings and customers within a neighbourhood from a central plant location or locations. Higher efficiencies and the potential to replace or combine traditional energy systems with renewable energy sources to improve system costs and reduce GHGs are among the reasons for implementing DES. TGI views district energy as an important part of its future service offerings.

DES can use a single, traditional energy source and technology such as high efficiency natural gas boilers to deliver large volumes of piped hot water throughout a neighbourhood or community. More recent developments, however, are tending to employ multiple emerging technologies to capture latent, or waste heat from the environment, supplemented by more traditional energy sources and equipment. For example, the latent heat from wastewater effluent flows feeding a nearby sewage treatment plant can be captured and converted to useable energy in much the same way that geo-exchange systems capture and convert latent heat from below the surface. Geo-exchange and solar thermal systems, as well as systems that capture waste heat from industrial process can also be employed.

These systems are often used in combination with high efficiency natural gas or electric boilers to provide baseload or back-up heating where higher temperature steam is required for heating or industrial processes or if the heat needs to be transported over greater distances. More recently, boilers are being designed to use biofuels such as wood wastes to reduce reliance on fossil fuel use. The centralization of equipment makes higher efficiency equipment more economic and reduces or removes the need for individual boilers, furnaces or other space and water heating equipment within each individual unit.

The combination of fuel sources and technologies employed by each DES will be unique, but most DES projects will have common elements. Heat capture systems include a separate piping system that captures the heat energy from its source, similar to those described for geo-exchange systems. One or more central plants are located in specifically designed mechanical rooms or buildings, housing boilers, heat exchangers, pumps and piping infrastructure. Piping systems will then distribute hot water and/or steam to multiple buildings and customers within the DES service area. Finally, each building or unit served by the DES may contain specific equipment to convert the distributed steam or hot water into useable energy specific to the needs of that customer. TGI's experience with DES and expertise in providing piped energy systems make DES a natural extension of its current service offerings.

(iii) Target Market

(a) Geo-exchange and Solar Thermal

Initially, TGI expects to provide geo-exchange and solar-thermal heating equipment and services to owners and/or operators of larger single or multi-use buildings including municipal, institutional, multi-family residential and commercial end users. Such a system or systems may serve one or a few buildings, but differ from district energy systems (see discussion in the next section) in scale, scope and complexity of the energy systems. Both installation and/or ongoing O&M for geo-exchange and solar-thermal heating systems can be provided either directly by TGI or through yet-to-be-identified alliance partners such as engineering service providers. TGI does not at this time expect to provide mass market geo-exchange or solar-thermal services to individual home owners, but may in the future. The target customers of this offering would be charged rates that would recover TGI's cost of service as described in the in the paragraphs which follow on Tariff Considerations and Economic Assessment.

(b) District Energy Systems

DES can serve a range of building use types (multi-family residential, commercial, industrial and institutional) and customers. Since DES are generally designed to serve multi-use neighbourhoods or communities, there are two levels of target markets to consider – the land use planner or developer, and the ultimate end-use customer. Safety, security and reliability are all highly valued by both of these target markets, making TGI an ideal utility to provide DES services and infrastructure.

Municipalities seeking to improve energy efficiency and reduce carbon emissions in their communities are among the proponents who will support the development of DES. Larger municipal buildings such as offices or recreational facilities might become anchor customers for DES, which are then expanded to serve other nearby customers as well. Similarly, large institutional customers, around which a host of similar land uses usually develop, could become anchor customers for a DES. Land developers might also seek DES to serve high density, mixed use developments being planned in urban locations.

Once a community with a DES is developed, the end use energy customers would be a range of building owners and tenants. These customers would be charged utility rates that would cover TGI's cost of service as described in paragraphs which follow on Tariff Considerations and Economic Assessment.

(iv) TGI's Role in Delivering these Alternative Energy Services

Terasen Gas intends to:

1. Invest in, provide financing for, supply energy, and deliver equipment;
2. Develop appropriate rate structures, subject to Commission approval, and billing practices;
3. Apply an Economic Assessment model to arrive at a rate for energy delivery;
4. Provide engineering, procurement and contracting services for installation of the hybrid energy systems (likely with third party resources); and,
5. Provide on-going maintenance services through service contract arrangements.

(v) Tariff Considerations

TGI is not proposing a blanket tariff for either solar, geo-exchange or DES systems at this time. However, in Part III, Section C, Tab 12, TGI proposes new language in the General Terms and Conditions to support the alternative energy service.

Each installation or combination of installations could have different mechanical equipment and piping infrastructure needs and therefore the cost inputs will vary between projects and as such each service agreement could have different language to reflect the nature of that business arrangement. In addition, each installation's (or customer's) cost may vary significantly and as such end use rates may be very different from one installation to the next. Therefore, for every TGI project, the Company will develop a service rate based upon the parameters outlined below and will then file, as a Tariff supplement, the contract (in redacted form if pricing or other information confidentiality is required for competitive reasons) for approval with the Commission. TGI proposes that the contract approval process be treated similarly to the gas supply contract approval process in that the process is confidential and expedient. So long as the customer has agreed to the rates and agreement and that is consistent with the methodology described below, we would propose that the agreement be approved as filed.

In order to support the provincial government's environmental and carbon emission objectives by implementing these types of alternative energy systems, an efficient process is required to achieve an appropriate level of oversight. We believe that the proposed process and structure described above strikes this necessary balance. Customers will have entered into contracts willingly and with full knowledge of how other energy solutions compare, rates will have been established based on the accepted cost of service model, contracts remain confidential to maintain business competitiveness, and lastly, contract approval will be swift to ensure that TGI and third parties can deliver on their individual and mutual obligations.

(vi) Economic Assessment and Service Rates

Any geo-exchange, solar-thermal or DES project for which capital costs exceed the Commission-approved limit over which TGI projects require a CPCN will proceed via a separate CPCN application. Otherwise, geo-exchange, solar-thermal and DES projects will proceed, with rates for the provision of energy to the customer being determined through the application of the proposed economic assessment.

For each geo-exchange, solar-thermal and DES system, TGI will conduct an economic assessment using a cost of service analysis according to traditional COS modeling practices and proposes that customer rates would be set on a project by project basis to return an amount equal to the levelized (over a 15 to 25 year timeframe) cost of service plus inflation. TGI recognizes that a customer's decision to proceed with an alternative energy system is not strictly an economic decision in comparison to rates for traditional energy systems. In other words, a customer may agree to pay rates for geo-exchange, solar-thermal energy, of DES services that are somewhat higher than costs for traditional gas or electric utility customers are paying at the time that the project proceeds based on their environmental and social values or their own belief of what traditional energy costs will be in the future.

One of the hurdles of adopting low carbon emitting alternative energy systems is the high up front capital and development costs. Typically the full costs of a new DES or alternative energy system occur right after the system comes into service whereas the customers are added over time, so in the absence of a rate smoothing or deferral mechanism the initial customers would have very high energy bills. A mechanism is required to ensure that the initial customers attaching to the system are not dissuaded from attaching due to higher initial energy costs. Conversely customers attaching in later years should not receive the benefit of lower rates (resulting from assets that have depreciated over a longer time period) from early customers paying higher costs. Levelizing the rate (and allowing inflation-based rate increases) over a twenty five year period provides a balanced solution that will promote more wide scale implementation. A long-term levelized approach (in the range of 15 to 25 years) yields a service rate that will incent customers to attach to a DES system in the early years and support the reduction of GHGs. Even under a rate levelizing approach there is still the likelihood of revenue shortfalls or surpluses in various stages of the project life. A mechanism (or mechanisms) to balance these shortfalls or surpluses such as an adjusted depreciation schedule may be needed to provide customers with competitive rates and maintain utility returns on investment at allowed levels. Such mechanisms, if needed, will be part of the project evaluation and included with the contract filing.

The economic assessment model that TGI will use to determine the rate that a customer would pay for geo-exchange, solar-thermal, or DES equipment and service would include the following life cycle costs and expenses for facilities, equipment, operations and maintenance:

<u>Capital Expenditures</u> – All equipment, materials, land and service costs required for the initial installation of the project, including equipment required within the building envelope as appropriate, as well as planned capital replacements through the life of the project, less any contributions made by the project developer. Although TGI proposes that service rates be based on levelized returns and that no specific upper limit be established vis-à-vis a cost of service analysis, it is likely that in some cases wherein the levelized cost of service is actually higher than comparative conventional systems, a customer will seek to balance the higher service rates with an appropriate up-front contribution.

<u>O&M Expenditures</u> – O&M expenses include, but are not limited to the labour, replacement parts, equipment, materials and administration required to maintain the ongoing effectiveness and safety of the energy system as well as overhead costs associated with TGI costs.

<u>Inflation</u> – Based upon inflation rate as reported by the Province of British Columbia

<u>Income Tax</u> – as per the applicable federal and provincial income tax rates

<u>Depreciation</u> – the depreciation treatment applied to a project will follow generally accepted accounting principles for the expected life span of each class of equipment. As such, depreciation periods may vary from project to project and on items within a project.

<u>Capital Cost Allowance</u> – as per Revenue Canada

TGI Capital Structure / Cost of Capital – as approved by the BCUC

Thermal Requirements (heating volume) – each project will have unique thermal heating requirements for space and/or water heating, determined by building design professionals as part of the development approval process. Furthermore, traditional energy service (natural gas and or electricity) will drive all or part of the energy system operation. If electricity and natural gas is separately metered, as likely to be the case for geo-exchange and solar thermal systems, then the TGI system charge will be a fixed monthly fee excluding metered energy costs. If electricity, natural gas, or other fuels are purchased by TGI to drive the alternative system, as will be the case for DES, then the TGI charge will include these costs as a pass-through to the customer. For easy comparison to the reference BC Hydro tier 2 rate, the annual cost of service for the project plus separate energy costs as appropriate can be divided by the annual thermal energy to determine an annual unitized cost per MWh.

Carbon Costs – With the exception of the provincial public sector carbon offset costs, and carbon tax, costs for emitting carbon from various types of energy systems (cap and trade) have not been fully defined or implemented. It is expected that such costs will become law, and will therefore be specifically identified in the near future. As such, the costs of carbon emissions need to be included on the expense side of the cost of service model and by extension, avoiding the cost of carbon emissions included on the benefits side of the model. This will act to somewhat improve the economic comparison between alternative energy and conventional energy systems. Until such time as these carbon emission costs are defined and formally implemented by the government, TGI will conduct a sensitivity analysis on the cost-of-service to assess their impact. Once carbon emission costs are institutionalized, they will be fully included in the cost-of-service analysis for alternative energy service.

Avoided cost of Equipment in Individual Units – Providing energy via DES removes or reduces the need for traditional heating equipment such as boilers, furnaces and/or electric heating equipment within the individual units or buildings. These avoided costs will be considered in developing the cost of service analysis for each project.

Project development would require a contract with the customer prior to proceeding. A sample contract, cost of service analysis, service rate and cash flow analysis are contained in Appendix C-27: Alternative Energy System Cost of Service.

c) Economic Assessment Model

The economic assessment models used to determine customer rates for alternative energy systems will be based on accepted utility practices in B.C. for determining revenue requirements and designing rates.

For demonstration purposes, Appendix C-27 provides sample analyses for both a discrete and a district alternative energy system. The examples include both a hypothetical discrete project and a real example of a district energy system. The analyses have been prepared based on experience from existing and recent projects as well as data gathered specific to each technology type.

The example analyses have been developed based on reasonable expectations of the type of projects envisioned by TGI. The two examples provided are chosen to demonstrate an understanding of the inputs and assumptions that will be used to prepare an economic analysis for a broad range of potential projects, from a simple, low cost solar-thermal system to much larger and more complex district energy system.

Included in Appendix C-27 along with the economic assessment models showing the rate base and revenue requirement summaries, are cash flow analyses for these example projects. The cash flow projections demonstrate how the capital investment, O&M, other costs and return on investment will be recovered through customer rates over the life of the project, based on typical build out assumptions and customer additions for land development projects of this nature.

The simple, discrete project example results in a relatively low customer service rate per GJ comparable to a conventional gas or electric energy system today, while the more complex district energy project results in higher rates. Both results are economically reasonable, given the specific circumstances of each project.

For the discrete energy project, in this case the installation of a solar thermal energy system that supplements a conventional domestic water heating system, the project displaces a portion of the conventional energy supply with carbon neutral, renewable energy, but does not remove the need for the conventional equipment. The customer fully understands the benefits and costs and chooses a simple, relatively low-cost solution. The customer pays for the system equipment and operation over time at a rate per unit of energy (or on a flat monthly charge basis) comparable with conventional systems, but avoids a portion of the conventional commodity cost.

For the more elaborate and complex district energy project, the system does replace the need for expensive equipment within each building as well as avoiding a high proportion of the commodity costs for conventional energy. Again, the customer has full knowledge of the available alternatives and the costs and benefits of the district energy system being examined. In this case the customer chooses a higher cost, more complex design that better meets their needs and objectives for a renewable, low carbon energy system. For this system, the customer pays for the system equipment, an alternative fuel source commodity (wood waste) and system operation and maintenance over time at a rate per unit of energy that is higher than that of BC Hydro's Step 2 RIB rate for residential electricity.

In both of these examples, the customer has chosen the energy system with full access to information on the costs and benefits of available alternatives and has chosen a system the best fits their needs. The customer pays for the system and its operation over time at a rate that is acceptable to them, but which does not unduly impact the rates of other TGI customers.

(1) FUTURE RATES FOR ALTERNATIVE ENERGY SERVICES

The above proposal to allow TGI to develop geo-exchange, solar-thermal and DES alternative energy services is intended to facilitate the implementation of alternative energy projects, in conjunction with our base gas business. We anticipate that TGI's involvement with these projects, subject to the regulatory treatment proposed above, will allow alternative energy systems to be more quickly and more broadly adopted than would otherwise be the case. As these services increase in popularity, and the systems and costs for the development of individual projects become more standardized, TGI expects that postage stamp rates may be developed for some of these services across our service region at some time in the future.

(2) CAPITAL AND REVENUE TREATMENT

As also stated in the section on NGV, the sales cycle for alternative energy is long, the nature of customer acquisition uncertain, the timeline of capital expenditures undetermined and associated O&M expenses unknown. TGI proposes forecasting zero capital additions, O&M expenditures and revenues in this area for the purpose of the RRA. As such, TGI believes it is prudent and therefore proposes that revenues, ongoing O&M and capital attributed to additions in 2010/11 be recorded in a non-rate base deferral account for the period of the RRA. In this manner, existing customers rates will not be impacted in 2010 and 2011 by capital and O&M expenditures, and associated revenues that are too uncertain to forecast at this time.

(3) SUMMARY

All levels of government and much of the general public in B.C., are committed to reducing the consumption of energy and reducing GHG emissions. TGI must adapt to these changes or risk becoming a provider of a single product that will continue to face reduced market demand. TGI is ideally positioned to deliver alternative energy solutions, in conjunction with its core gas business, within a transparent environment of regulatory oversight that provides security in a levelized cost approach. The increased adoption of alternative energy systems that we expect will result, will act more quickly and in a more meaningful way than current market trends can deliver to help meet the targets set out by the Province and the expectations of TGI customers and the BC public in general. TGI's participation in alternative energy systems in this way will help our customers access broader energy solutions.

4. Gas Sales and Transportation Demand

This section provides a discussion of the demand for natural gas, comprised of natural gas sales and transportation volumes forecast for 2010 and 2011. The forecast of demand for natural gas, including the forecast number of customers and customer additions by customer class, and forecast average use per customer by customer class, is an important component of the RRA. The forecast number of customers and customer additions are key cost drivers for both operating and capital costs to be incurred in order to serve our customers. Additionally, the forecast demand is a key input in the determination of the delivery rates needed to recover the revenue requirements. The forecast of demand for natural gas included in the RRA is based upon a methodology that is consistent with that used in prior years, and provides a reasonable estimate of future natural gas demand. TGI is of the view that the forecast of demand for natural gas included in this RRA fairly represents the expected customer additions and average use per customer for 2010 and 2011, and is the most appropriate forecast of demand for natural gas to be used in the determination of rates for the 2010 and 2011 forecast period. The forecast total demand for 2010 and 2011 continues to decline as compared to the previous period, which is attributable to a further decline in average use per customer that is not offset by the forecast low number of customer additions.

Included in this section is a discussion of the:

- Forecast methodology;
- Underlying assumptions; and
- Forecast of residential, commercial, and transportation revenues and margins.

a) Energy Forecast Methodology

This section discusses the methodology used in preparing the forecasts for the RRA. The energy forecast methodology provides a reasonable approach to estimating future energy demand for the Company, for the following reasons:

- The methodology is consistent with the approach taken in prior revenue requirements applications;
- The methodology has been reviewed and accepted internally; and
- The methodology has been reviewed and accepted by the BCUC and stakeholders at the Company's annual reviews, which were conducted under the PBR Period.

As with prior years, the energy demand forecast is comprised of three main components:

- Customer additions forecast;
- Average use per customer forecast; and
- Industrial demand forecast.

The forecast of customer additions reflects macroeconomic factors affecting residential and commercial customers. The forecast for industrial customers assumes no net change in the number of customers over the forecast period except where specific knowledge of a change in service level has been received by the Company.

The forecast of usage on a per customer basis, again consistent with prior years, is based upon an analysis of recent historical normalized consumption data and also incorporates market trends affecting consumption.

The forecast of industrial energy demand, due to the smaller number of customers in each rate class and also the unique characteristics influencing customer additions, is based upon sector analyses and customer specific survey results.

The residential and commercial energy forecast is driven by the respective customer account and use per customer forecasts, and incorporates customer rate classes 1, 2, 3, and 23. The industrial energy forecast incorporates customer rate classes 5, 7, 22, 25, and 27.

The energy forecast methodology for customer accounts, average use per customer, and industrial energy demand is reasonable, consistent with prior years, and reflects the best information available at the time of this Application and is the most appropriate forecast of energy demand to be used in the determination of rates for the 2010 and 2011 forecast period.

A significant aspect of the methodology for developing the demand forecast is the review of historical data, as it is through this review process that characteristics of our customer base, such as the number and types of current customers, the amount and pattern of gas usage by those customers, and the trends/relationships between those characteristics and various economic indicators are determined. Those trends/relationships are then considered in conjunction with the latest forecasts of various economic indicators (underlying assumptions) to determine whether or not it is reasonable to assume those trends/relationships will continue into the future, and ultimately impact the future demand for natural gas.

(1) UNDERLYING ASSUMPTIONS

One of the steps involved in developing the demand forecast is to identify the main factors that influence the demand for natural gas, and then develop assumptions regarding the impact those factors will have in the future. As with prior years, the factors considered in developing the energy demand forecast for this RRA include current economic conditions, the housing market, government policies and programs, and also general trends regarding efficiency improvements. Through reviewing the best information possible at the time of this forecast, which included information from the B.C. Government, major banks and other organizations, TGI has developed a set of reasonable underlying assumptions that are appropriately applied in forecasting future energy demand.

The underlying assumptions made regarding external influences that affect the demand for natural gas were:

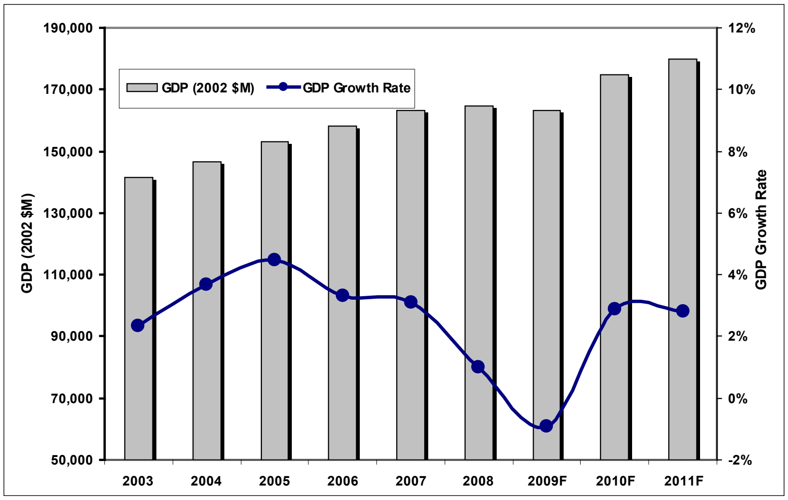
- Although the B.C. economy is currently contracting, and is assumed to continue doing so throughout 2009, recovery is anticipated in 2010 and 2011[165];
- The housing market declines in both 2009 and 2010 before stabilizing in 2011[166];
- Energy efficiency will continue to improve driven by the current suite of government policies and programs, the Company's own EEC programs[167], and also ongoing appliance renewals ; and
- Key industrial sectors will continue to experience adverse conditions as a result of the global economic crisis.

As noted above, the B.C. economy is no longer enjoying the high levels of economic growth that have been experienced over recent years. This is attributed to the slowdown of the U.S. economy and the ensuing collapse of the financial markets. The consensus among leading economists[168] is that the provincial economy will contract in 2009, but will show signs of recovery in 2010 primarily due to the anticipated economic benefits resulting from the 2010 Olympic and Paralympic Winter Games. Growth is expected to continue in 2011, but at a slightly lower pace. The B.C. Ministry of Finance is projecting

[165] See Appendix C-34 for a copy of British Columbia Budget 2009
[166] See Appendix C-37 for a CMHC Housing Market Outlook - BC Region Highlights First Quarter 2009 and Appendix C-29 for a copy of B.C. Fiscal Plan 2009
[167] See Part III, Section C, Tab 3 for a further discussion of our EEC Programs
[168] See Appendix D-2 for a copy of BMO Provincial Economic Outlook January 2009
See Appendix C-38 for a copy of RBC Economics March 2009
See Appendix D-3 for a copy of TD Economics – Provincial Economic Forecast March 2009
See Appendix D-4 for a copy of Central 1 Credit Union- BC Economic Forecast 2009 – 2013

economic growth of -0.9 per cent for 2009, 2.4 per cent in 2010, and then 2.6 per cent in 2011[169], as illustrated in the following Figure C-4-1.

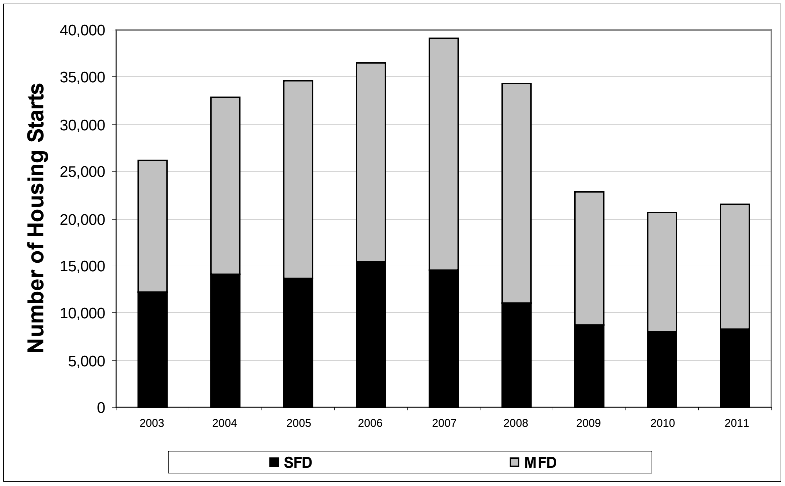
Figure C-4-1: Provincial GDP contracting in 2009



The B.C. housing market experienced strong growth over the period 2004 through 2008, with record levels of housing starts being realized in 2007 (39,150 housing starts). After declining slightly in 2008 (from 2007 levels), housing starts are expected to dramatically decline in 2009 and continue declining in 2010 before stabilizing in 2011. The CMHC is projecting a 34 per cent decline in housing starts from 2008 levels, to 22,800 starts in 2009, followed by a further decline to 20,700 housing starts in 2010, and then an increase to 21,475 housing starts in 2011. This is illustrated in the following Figure C-4-2.

[169] See Appendix C-34 for a copy of British Columbia Budget 2009

Figure C-4-2: Significant slowdown in B.C. Housing Starts



The underlying assumptions made regarding external influences that affect the demand for natural gas are reasonable, consistent with prior years, and are based upon a review of the best possible information available at the time of the forecast. Furthermore, together these assumptions provide an appropriate basis for the determination of our customer additions forecast.

b) Customer Additions Forecast

Although our Company is challenged by a troubled economy, a declining housing market, and a shift towards more multi-family dwellings in the housing mix (where our capture rates are significantly lower than for single-family dwellings), new customer attachments are still anticipated over the forecast period. The forecast of customer additions is reasonable and, consistent with prior years, is based upon the provincial forecast of household formations at the community level, and is appropriate for the use in determining rates for the 2010 and 2011 forecast period.

The CMHC's forecast, along with the latest economic analyses from the B.C. Government, major banks and other organizations are also reviewed for consistency with the overall trend in household formations. The forecast of customer additions is applied to residential and commercial customer classes. No growth is assumed for industrial customers unless known at the time of the forecast.

The Table C-4-1 below provides a summary of the residential, commercial and industrial and transportation gross and net customer additions projected for 2009, and the forecast for the years 2010 and 2011.

Table C-4-1: Forecast Customer Growth[1] is Flat and Lower Than in 2009

	2009 Projected	2010 Forecast	2011 Forecast
Residential[2]	5,213	4,777	4,983
Commercial[3]	907	823	867
Industrial & Transportation[4]	-	-	-
Total Net Additions	**6,120**	**5,600**	**5,850**
Total Gross Additions	**9,600**	**8,784**	**9,176**
Year-Ending Customers	837,965	843,565	849,415
Housing Starts[5]	22,800	20,700	21,500

Notes
1. Includes Lower Mainland, Inland, Columbia and Revelstoke service regions only.
2. Rate 1
3. Rates 2, 3 & 23
4. Rates 4, 5, 6, 7, 22, 25 & 27
5. Source: CMHC, B.C. Ministry of Finance
6. Includes 3,124 additional customers due to amalgamation of Squamish customers

The above forecast of customer additions incorporates the best available information, is based on a methodology consistent with prior years, and is both reasonable and appropriate for use in this Application.

Customer Growth Issue

Over the past several years, TGI experienced an increase in the net turnover of its customer base, which has negatively affected our customer growth. TGI has investigated this issue and has determined that it is appropriate to incorporate into the demand forecast a stable customer turnover factor so as to maintain the reasonableness of the demand forecast and ensure that the best available information has been incorporated.

Customer turnover represents the difference between the number of meters either locked off (due to the customer falling into arrears) or being removed from the system (due to a premise becoming vacant, or customers moving) in a particular year, and those that return to the system in that same year.

The issue with customer turnover is the fact that for the past several years TGI has experienced an increase in the net turnover in its customer base, which has resulted in significantly fewer net customer additions than forecast. This is illustrated in Figure B-1-3 of Part III, Section B. Customer turnover appears cyclical in nature, and current year-to-date results indicate a downturn may be taking place. However, current economic conditions may lead to an increase in net customer turnover (as the likelihood of an increase in lock-offs is increased). Given this, TGI has assumed for the purposes of its demand forecast that net customer turnover will remain relatively stable over the forecast period.

Since customer turnover affects customer growth, this factor has been incorporated into the demand forecast. By incorporating this factor into the demand forecast, TGI believes the demand forecast remains reasonable and reflects the best information available.

c) Use Per Customer Forecast

Individual average use per customer projections are developed for each service area and for each residential and commercial customer class. The analysis of historical normalized use per account[170] indicates a downward trend in residential average use per customer, while commercial average use per customer is proving to be more stable.

The forecast of average use per customer for residential and commercial rate classes is reasonable and, consistent with prior years, considers a number of factors. These factors include:

- Recent historical normalized use per account;
- Efficiency improvements, including appliance and insulation upgrades;
- Trends in the market; and
- Customer migration between customer classes.

Also incorporated into the forecast of average use per customer for the commercial customer classes is a sector analysis for the top five consuming sectors. After briefly describing the four factors listed above, a review of the sector analysis is provided below.

Average use per customer is influenced by a number of factors, including the retrofit of appliances, the housing mix, and also government policies and programs aimed at improving efficiencies. It is important to review historical consumption levels, as it is through this process that TGI is able to estimate trends in the market, and more importantly, determine whether or not those trends are likely to continue into the future.

Efficiency improvements are assumed to be the primary driver of the decline in residential average use per customer. These would include the retrofit of older, less efficient appliances with new high efficiency units, and also upgrades to insulation, window, doors, and more generally speaking, building

[170] See Appendix D-1 for a copy of Consumption History

shells. Although efficiency improvements are driven by a number of factors such as technological advances, natural gas prices, and public policies/programs, they are also influenced by the Company's EEC programs. Since TGI recently received approval for EEC programs that have significantly greater levels of funding, it is reasonable to assume that these will impact average use per customer over the forecast period. The impact, although negligible in 2009, are estimated to be as great as a 0.3 GJ decline in residential average use per customer.

There are also other factors contributing towards the trends seen in average use per customer. TGI has observed a continued shift towards more multi-family dwellings in the housing mix, the carbon tax has been recently introduced, and also various programs have been developed as a result of the energy savings targets outlined in the B.C. Energy Plan. All of these factors are contributing towards a downward trend in average use per customer.

Analysis of building types, and, more importantly, expected future trends in the market regarding the future housing/building mix, is an important part of forecasting future demand for natural gas. The following Table C-4-2 illustrates the estimated annual use per customer for residential customers by building type.

Table C-4-2: Annual Consumption (GJ/yr) by Housing Type – Significant differences

Housing Type	2007 Normal
Single Family Dwelling	94
Multi-Family Dwellings	60
Vertical Subdivision	23

Source: 2008 Residential End Use Study

The above table illustrates the fact that residential customers consume different amounts of natural gas depending on their housing type. This is not surprising, since different housing types have different characteristics that lead to different opportunities for which to use natural gas. For commercial customers, since there are many different types of businesses as well as building types, analyzing average annual use by building type is much more difficult.

For residential customers, there is not only a difference in consumption levels by housing type, but also within each housing type. For each housing type, there are differences seen in the size of homes, insulation levels, appliance mixes, appliance efficiencies, and also differences in the lifestyles of those living in the home. The following Figure C-4-3 illustrates some of the differences that can be seen within single family dwellings.

Figure C-4-3: Energy Efficiency Significantly Impacts Annual Consumption

Older Low Efficient Home in Vancouver

- One storey building with basement
- 2,500 square foot older home
- Below average insulation in ceiling and walls
- Single pane windows (USI 6.7 - Single)
- Average temperature 19 degrees Celsius
- Air tightness: 6.0 ACH (tested at 50 Pascals)
- Standard efficient furnace, AFUE of 71%

Space Heating Energy = 137.6 GJ/yr

New High Efficient Home in Vancouver

- One storey building with basement
- 2,500 square foot new home (code compliant)
- Above average insulation in ceiling and walls
- Energy Star windows (USI 2.0)
- Average temperature 21 degrees Celsius
- Air tightness: 5.4 ACH (tested at 50 Pascals)
- High efficiency condensing furnace, AFUE of 90%

Space Heating Energy = 50.7 GJ/yr

Source: Modelled through Natural Resources Canada's HOT 2000 software

If two homes that are identical in size are considered, as illustrated above, the opportunity for variations in annual consumption can be seen. Homes with below average levels of insulation, single pane windows, and low efficient furnaces can consume more than twice as much natural gas (for space heating) than homes with high levels of insulation, energy star rated windows and high efficient furnaces. Given this, it is important to consider future trends in not only building types but also efficiency improvements and technological advancements when developing the demand forecast.

Customer migration, in the commercial customer classes, is another factor that affects average use per customer. Customers with annual consumption that falls outside the consumption range specified under their current rate class can skew the average use per customer for the entire customer class. Consumption for this group of customers is reviewed annually to determine whether or not there will be an impact to average use per customer, and if there is, to what extent.

(1) COMMERCIAL SECTOR ANALYSES

Similar to the sector analyses TGI performs for its industrial customers annually, TGI has identified the top five consuming sectors within its commercial customer classes, and analyzed those individually while preparing the demand forecast. By analyzing historical consumption patterns on a sector by sector basis, and incorporating the latest available economic information, TGI is able to prepare a demand forecast that is both reasonable and appropriate for determining rates for its commercial customers over the forecast period.

Analyses have been performed for small commercial (Rate 2), large commercial (Rate 3), and also Commercial Transportation (Rate 23) customers. Following are the results of the analyses.

(a) Small Commercial (Rate 2) Customers

The following Table C-4-3 illustrates the 2008 energy consumption and percentage each industry represents out of the total. As can be seen, there are five sectors that together represent over two-thirds of the total small commercial 2008 demand volumes. The "other" sector is comprised of the remaining lower consuming sectors (for this customer class) and includes the transportation, printing, recreation, and construction sectors. Each of these six sectors was analyzed individually, providing a reasonable basis from which to develop the small commercial demand forecast.

Table C-4-3: Small Commercial (Rate 2) Top Consuming Sectors

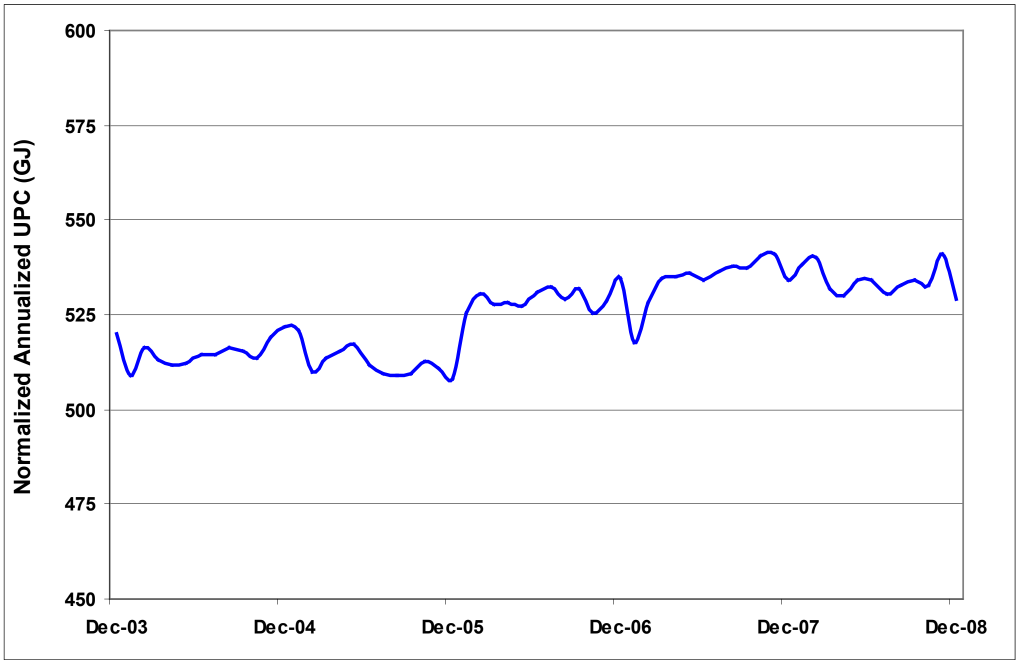
	TJs	%
Apartment/Condo	5,860	25%
Commercial/Office Building	2,430	11%
Education	1,120	5%
Restaurant	2,490	11%
Wholesale/Retail	3,830	17%
Other	7,340	31%
Total	**23,070**	**100%**

The above listed sectors are those for which sector analyses have been completed, historical consumption trends analyzed, and results have been validated against the most recent available economic information.

6. Apartment/Condo

The Apartment/Condo sector consumed 25 per cent of the total natural gas that was consumed within the small commercial customer class in 2008. The following Figure C-4-4 illustrates the normalized annualized average use per customer over the period December 2003 through December 2008.

Figure C-4-4: Apartment/Condo Sector – Relatively stable historical trend

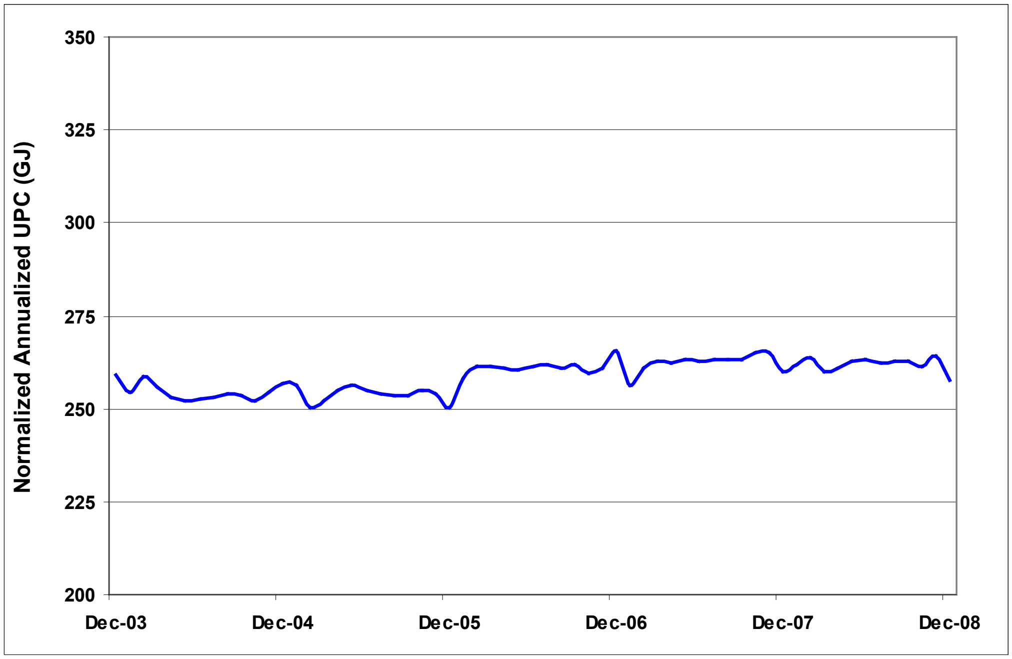


The Apartment/Condo sector within this customer segment represents multi-family dwellings, smaller apartment or condominium buildings. The historical trend in average use per customer is relatively stable (within a 10 per cent variance over the five year period), but as there are opportunities for efficiency improvements (especially given our recent EEC application approval), TGI is expecting a decline in average use per customer over the forecast period. Since these customers are residential, TGI is expecting similar declines in average use per customer over the forecast period as are expected for our Residential customer class.

7. Commercial/Office Building

The Commercial/Office Building sector consumed 11 per cent of the total natural gas that was consumed within the small commercial customer class in 2008. The following Figure C-4-5 illustrates the normalized annualized average use per customer over the period December 2003 through December 2008.

Figure C-4-5: Commercial/Office Building Sector – Stable since 2003

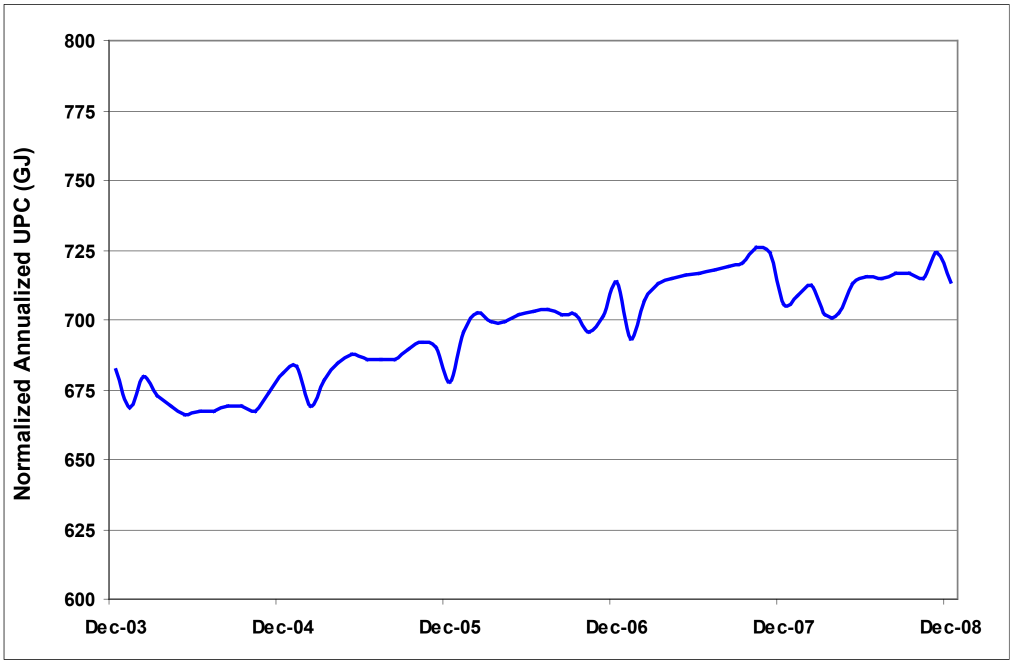


The Commercial/Office Building sector within this customer segment includes smaller commercial or office buildings, typically strip malls and other small stand alone structures. The average use per customer for this sector has been very stable since 2003, and is expected to remain stable over the forecast period.

8. Education

The Education sector consumed 5 per cent of the total natural gas that was consumed within the small commercial customer class in 2008. The following Figure C-4-6 illustrates the normalized annualized average use per customer over the period December 2003 through December 2008.

Figure C-4-6: Education sector – Trending upward since 2004

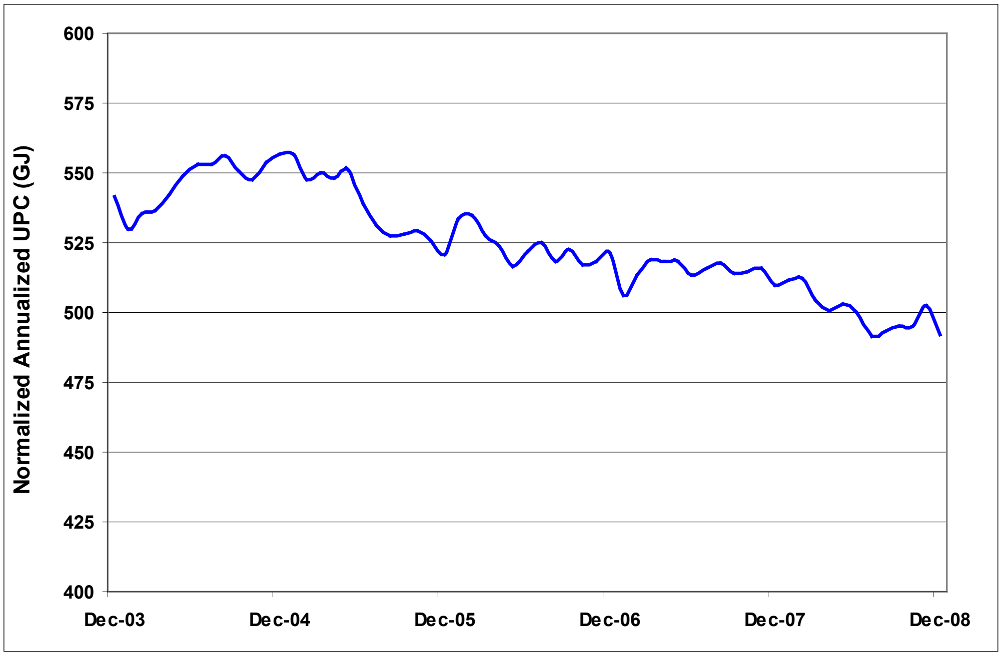


The Education sector within this customer segment includes larger schools with annual consumption less than 2,000 GJ per year. The average use per customer for this sector has been increasing since 2004. However, given there are opportunities for efficiency improvements, and also the possibility of alternative energies playing a growing role in this sector, TGI does not believe that the upward trend will continue and is projecting stable average use per customer over the forecast period.

9. Restaurant

The Restaurant sector consumed 11 per cent of the total natural gas that was consumed within the small commercial customer class in 2008. The following Figure C-4-7 illustrates the normalized annualized average use per customer over the period December 2003 through December 2008.

Figure C-4-7: Restaurant sector – Downward trend since 2004

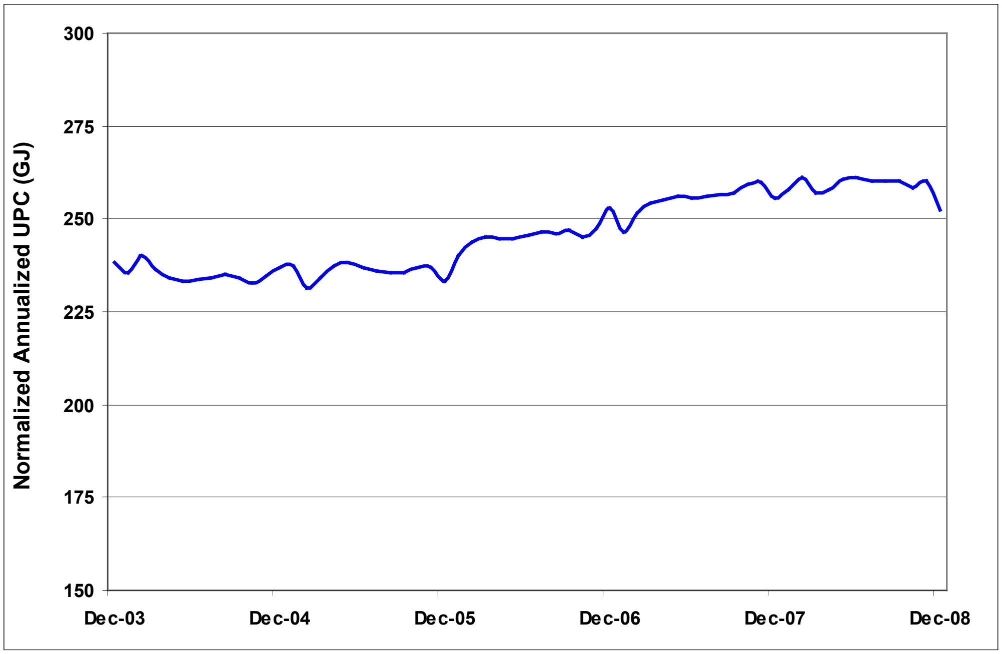


The Restaurant sector within this customer segment includes smaller restaurants, delis, and coffee shops. The average use per customer for this sector has been declining since 2004, although it showed signs of stability from 2005 through 2007 before declining again in 2008 (likely due to the economic downturn). This sector typically uses natural gas for cooking, hot water, dishwashing, space heating, and patio heating. Given those end uses, there are opportunities for efficiency gains to be made. TGI is therefore projecting average use per customer to moderately decline for this sector throughout the forecast period.

10. Wholesale/Retail

The Wholesale/Retail sector consumed 17 per cent of the total natural gas that was consumed within the small commercial customer class in 2008. The following Figure C-4-8 illustrates the normalized annualized average use per customer over the period December 2003 through December 2008.

Figure C-4-8: Wholesale/Retail sector – Relatively stable since 2006

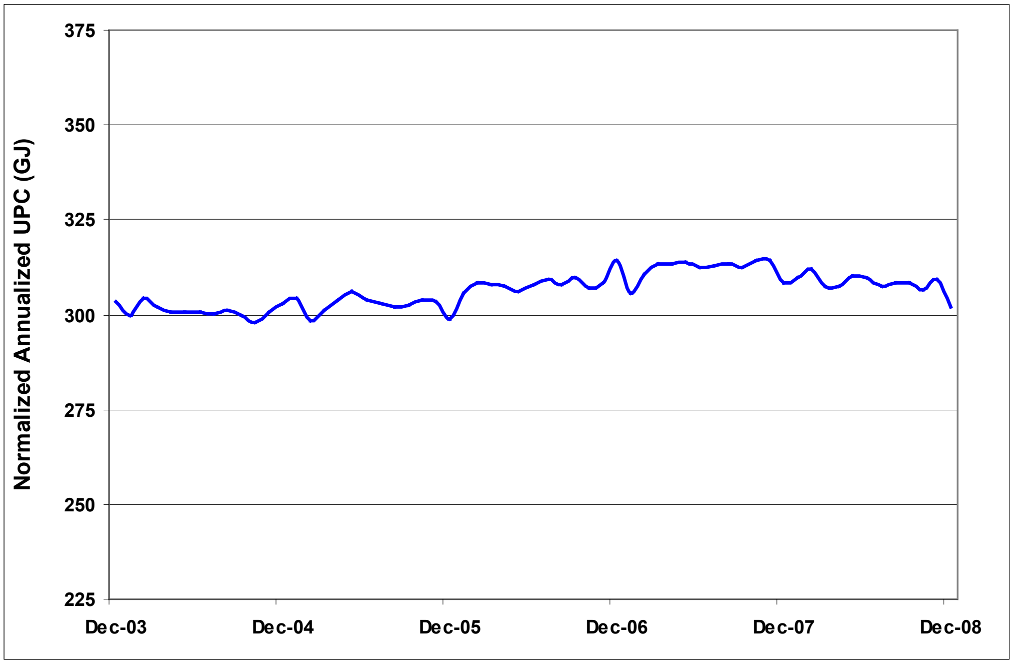


The Wholesale/Retail sector within this customer segment includes smaller stand alone retailers or wholesalers. The average use per customer for this sector was stable over the period 2003 through 2005, then increased through 2006, and has been relatively stable since then. Given the current state of the economy, and the lack of significant growth projected over the next few years, TGI is projecting average use per customer to decline moderately over the forecast period.

11. Other

The "Other" sector is comprised of all industries other than those illustrated above, and together they consumed 32 per cent of the total natural gas that was consumed within the small commercial customer class in 2008. The following Figure C-4-9 illustrates the normalized annualized average use per customer over the period December 2003 through December 2008.

Figure C-4-9: Other sectors – Relatively stable since 2003



The "Other" sector within this customer segment has experienced stable average use per customer, with an average 0.1 per cent annual decline since 2003. The more recent trend since 2005 has been a 1 per cent average annual increase, but since the most recent trend since 2007 is downward and also considering the current economic situation, TGI is projecting average use per customer for the "other" sector to decline moderately over the forecast period.

(b) Large Commercial (Rate 3) Customers

The following Table C-4-4 illustrates the 2008 energy consumption for large commercial (Rate 3) customers and the percentage each sector represents out of the total. As can be seen, there are five sectors that together represent over two-thirds of the total large commercial 2008 demand volumes. The "other" sector is comprised of the remaining lower consuming sectors (for this customer class) and includes the construction, hotel, printing, and transportation industries. Each of these six sectors was analyzed individually, providing a reasonable basis from which to develop the large commercial demand forecast.

Table C-4-4: Large Commercial (Rate 3) Top Energy Consuming Sectors

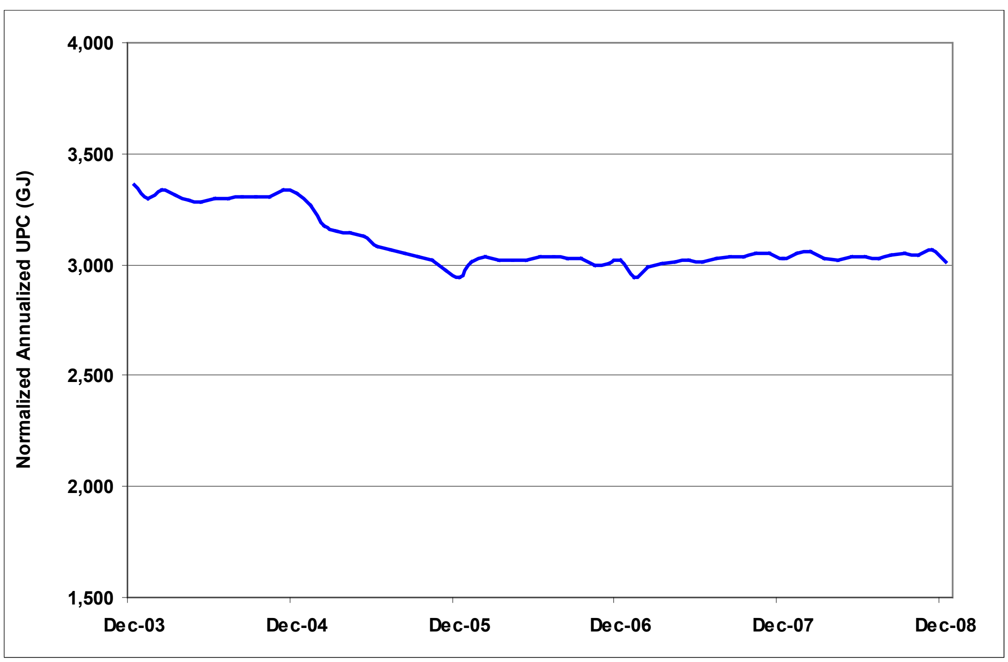
	TJs	%
Apartment/Condo	6,820	43%
Commercial/Office Building	870	6%
Hotel	570	4%
Restaurant	990	6%
Wholesale/Retail	1,360	9%
Other	5,000	32%
Total	**15,610**	**100%**

The above listed sectors are those for which sector analyses have been completed, historical consumption trends analyzed, and results have been validated against the most recent available economic information.

12. Apartment/Condo

The Apartment/Condo sector consumed almost half (43 per cent) of the total natural gas that was consumed within the large commercial customer class in 2008. The following Figure C-4-10 illustrates the normalized annualized average use per customer over the period December 2003 through December 2008.

Figure C-4-10: Apartment/Condo sector – Stable since 2005

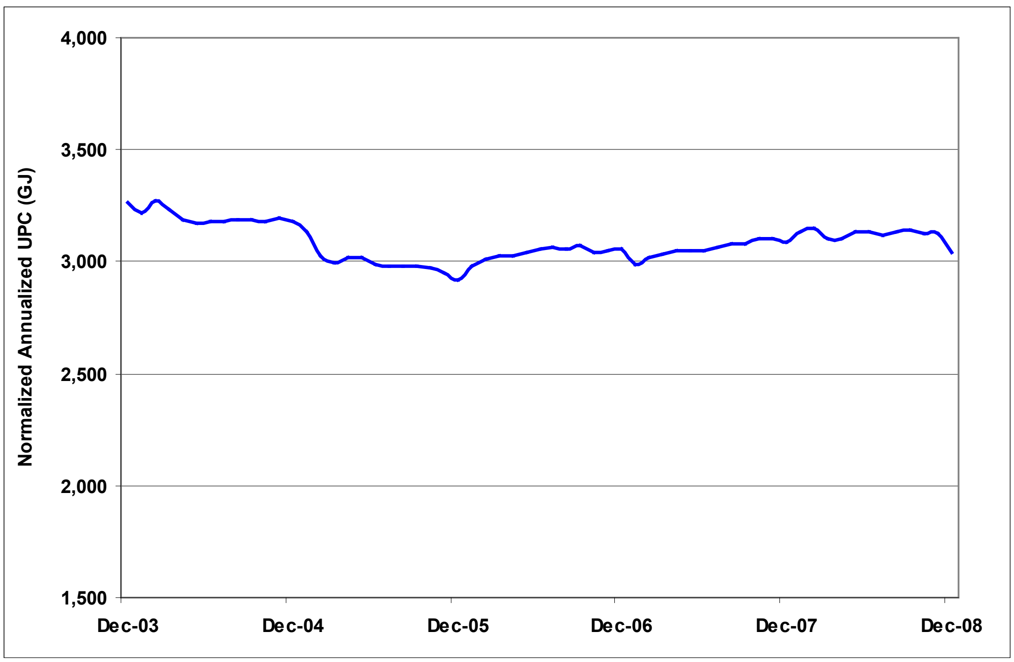


The Apartment/Condo sector within this customer segment represents multi-family dwellings, mid-size apartment or condominium buildings. The historical trend in average use per customer has been very stable since 2005, but as with this sector in the small commercial customer segment, there are opportunities for efficiency improvements. TGI is projecting a decline in average use per customer over the forecast period

13. Commercial/Office Building

The Commercial/Office Building sector consumed 6 per cent of the total natural gas that was consumed within the large commercial customer class in 2008. The following Figure C-4-11 illustrates the normalized annualized average use per customer over the period December 2003 through December 2008.

Figure C-4-11: Commercial/Office Building sector – Relatively stable since 2004

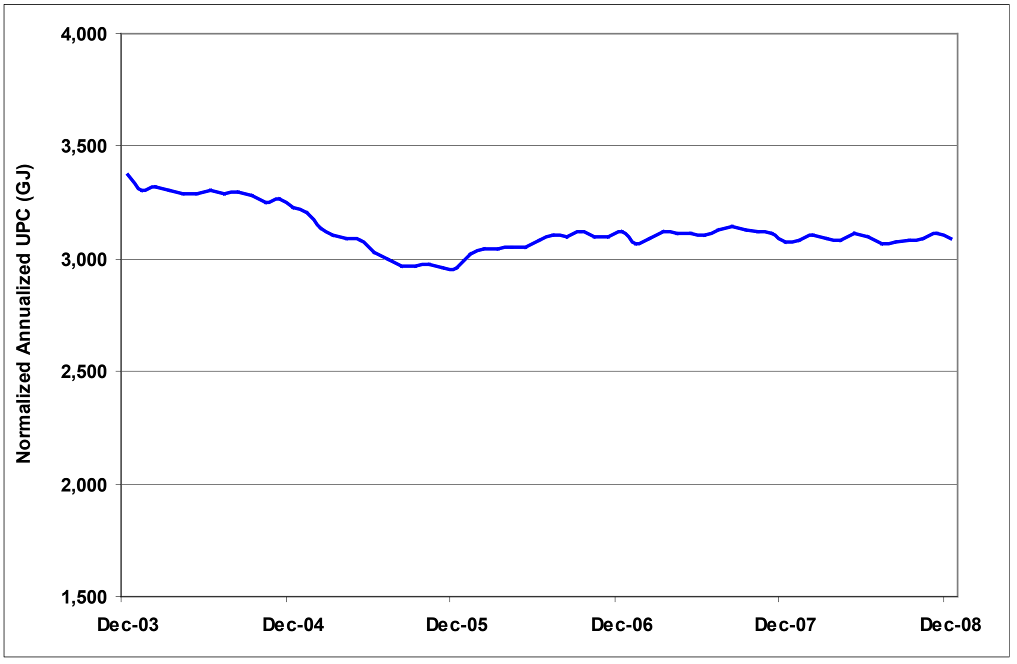


The Commercial/Office Building sector within this customer segment includes larger commercial or office buildings. The average use per customer for this sector has been relatively stable since 2004 (consumption has varied less than 10 per cent over the period). As with this sector in the small commercial customer segment, TGI is projecting stable average use per customer rates throughout the forecast period.

14. Hotel

The Hotel sector consumed 4 per cent of the total natural gas that was consumed within the large commercial customer class in 2008. The following Figure C-4-12 illustrates the normalized annualized average use per customer over the period December 2003 through December 2008.

Figure C-4-12: Hotel sector – Stable since 2006

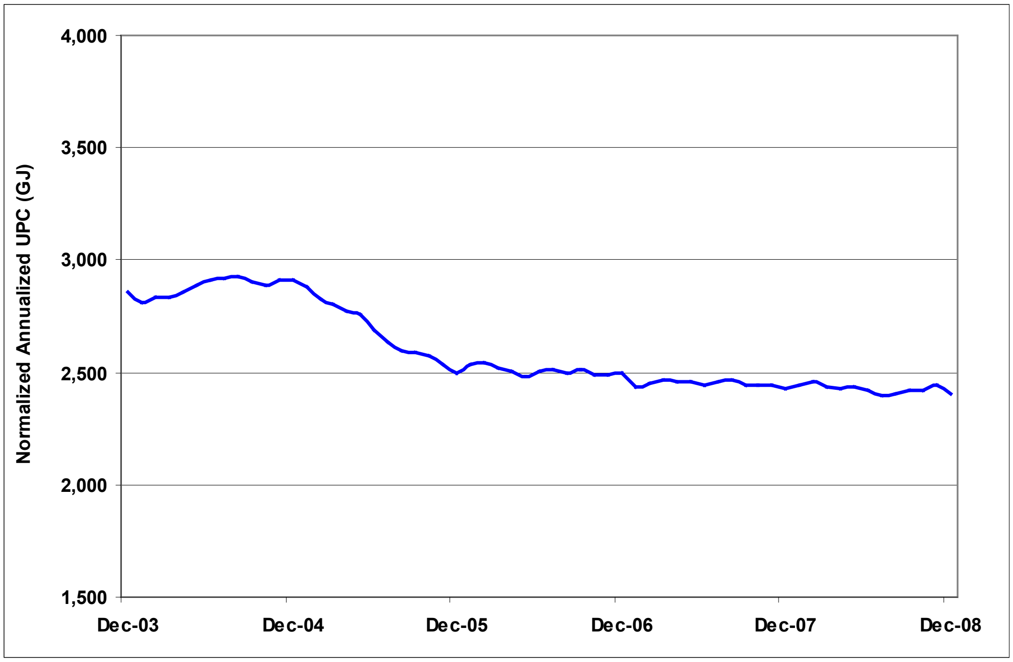


The Hotel sector within this customer segment includes small to medium-sized hotels. The average use per customer for this sector has been stable since 2006, after experiencing declines during 2004. Given the recent stability in average use per customer, TGI is projecting average use per customer to remain stable throughout the forecast period.

15. Restaurant

The Restaurant sector consumed 6 per cent of the total natural gas that was consumed within the large commercial customer class in 2008. The following Figure C-4-13 illustrates the normalized annualized average use per customer over the period December 2003 through December 2008.

Figure C-4-13: Restaurant sector – Moderately declining since 2005

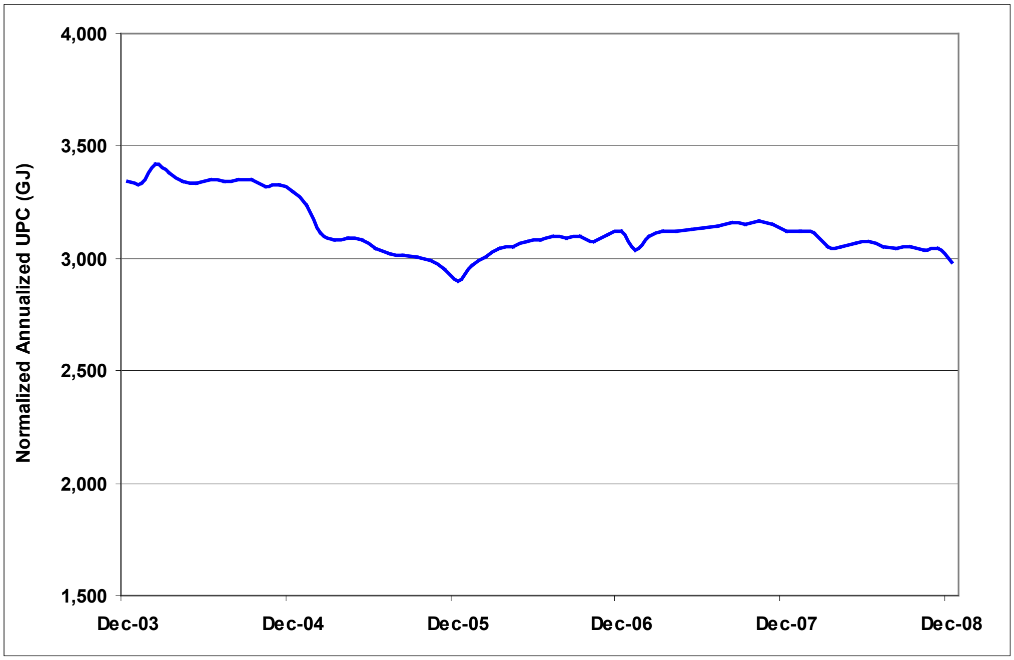


The Restaurant sector within this customer segment includes larger restaurants consuming more than 2,000 GJ per year. The average use per customer for this sector has been declining moderately since 2005, after experiencing more significant declines during 2004. This, together with the opportunities for efficiency improvements (as with the small commercial customer segment), TGI is projecting average use per customer to decline moderately over the forecast period.

16. Wholesale/Retail

The Wholesale/Retail sector consumed 9 per cent of the total natural gas that was consumed within the large commercial customer class in 2008. The following Figure C-4-14 illustrates the normalized annualized average use per customer over the period December 2003 through December 2008.

Figure C-4-14: Wholesale/Retail sector – Relatively stable since 2005

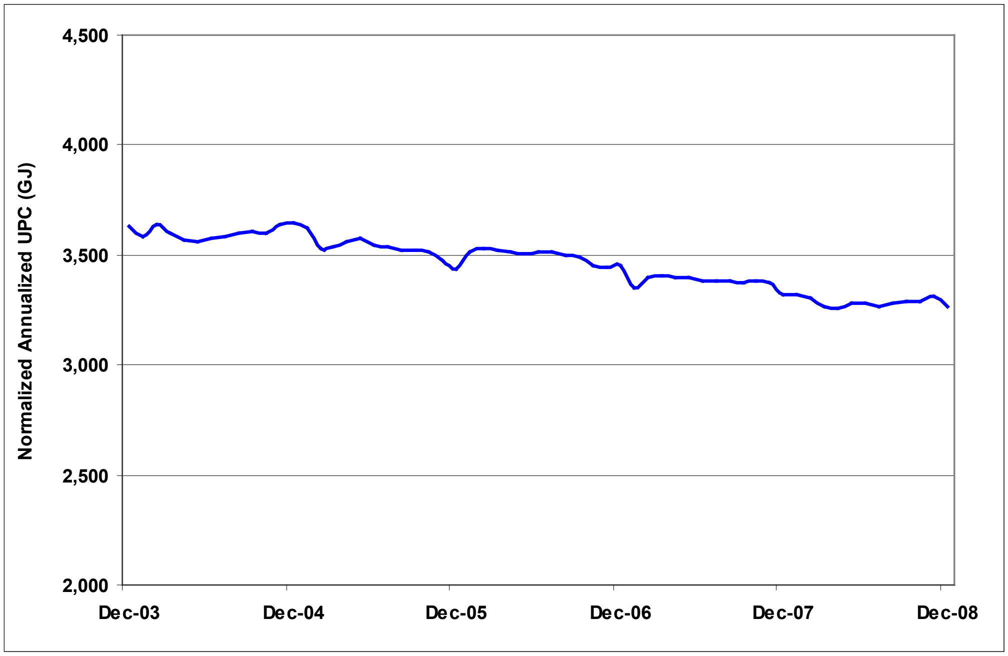


The Wholesale/Retail sector within this customer segment includes mid-to-large sized retailers or wholesalers. The average use per customer for this sector declined from 2003 through 2005, but has since remained relatively stable. As with this sector for the small commercial customer segment, TGI is projecting average use per customer to remain stable over the forecast period.

17. Other

The "Other" sector is comprised of all industries other than those illustrated above and together they consumed 32 per cent of the total natural gas that was consumed within the small commercial customer class in 2008. The following Figure C-4-15 illustrates the normalized annualized average use per customer over the period December 2003 through December 2008.

Figure C-4-15: Other sectors – Declining moderately since 2003



The "Other" sector within this customer segment has experienced declining average use per customer since 2003, but since early 2008 this trend appears to have slowed. The trend since 2003 has been a 2 per cent annual decline in average use per customer, but the more recent trend since 2006 is a 1 per cent annual decline. The more recent trend is assumed to continue going forward, and TGI is therefore projecting a moderate decline in average use per customer for this sector over the forecast period.

(c) Commercial Transportation (Rate 23) Customers

The following Table C-4-5 illustrates the 2008 energy consumption for commercial transportation (Rate 23) customers and the percentage each industry represents out of the total. As can be seen, there are five sectors that together represent 70 per cent of the total commercial transportation 2008 demand volumes. The "other" sector is comprised of the remaining lower consuming sectors (for this customer class) and includes the health, hotel, recreation and transportation sectors. Each of these six sectors was analyzed individually, providing a reasonable basis from which to develop the commercial transportation demand forecast.

Table C-4-5: Commercial Transportation (Rate 23) Top Energy Consuming Sectors

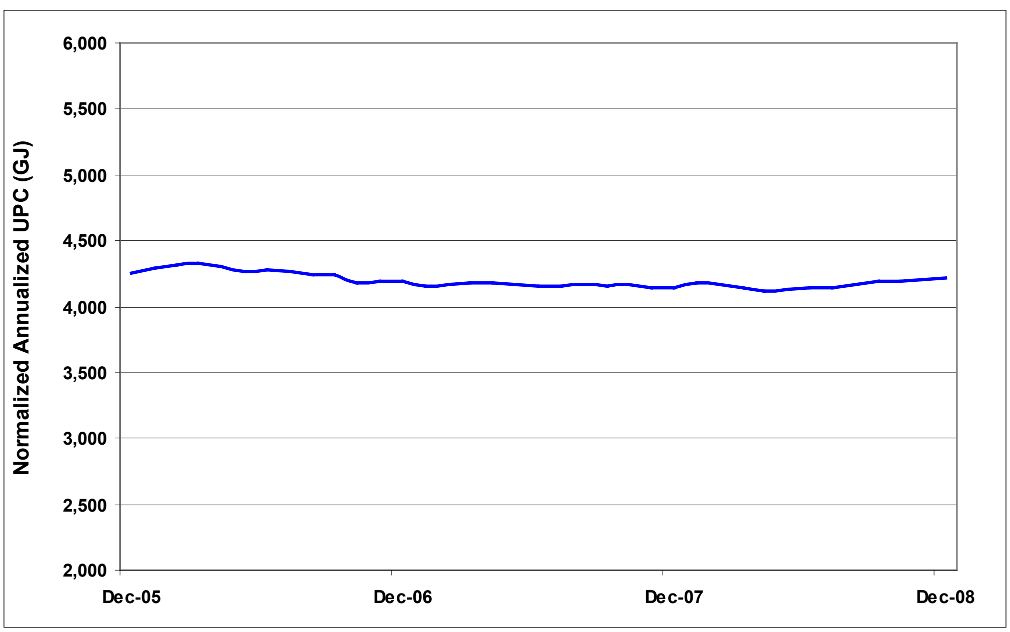
	TJs	%
Apartment/Condo	1,510	24%
Education	1,090	17%
Government Building	490	8%
Greenhouse	740	12%
Wholesale/Retail	600	9%
Other	1,910	30%
Total	**6,340**	**100%**

The above listed sectors are those for which sector analyses have been completed, historical consumption trends analyzed, and results have been validated against the most recent available economic information.

18. Apartment/Condo

The Apartment/Condo sector consumed almost one-quarter (24 per cent) of the total natural gas that was consumed within the commercial transportation customer class in 2008. The following Figure C-4-16 illustrates the normalized annualized average use per customer over the period December 2005 through December 2008.

Figure C-4-16: Apartment/Condo sector – Stable since 2005

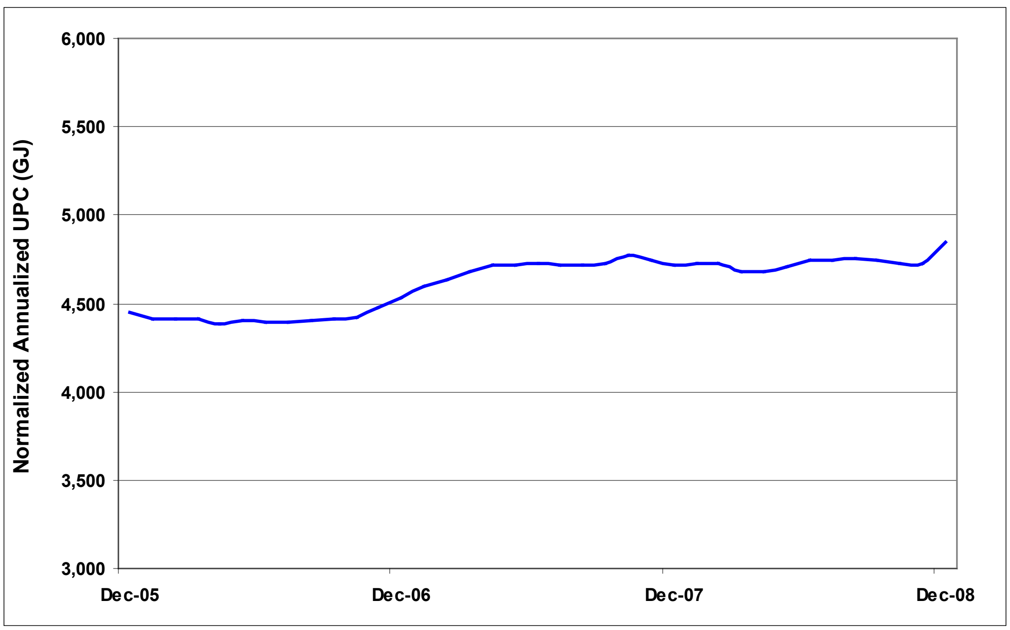


The Apartment/Condo sector within this customer segment represents larger multi-family dwellings, apartment or condominium buildings. The historical trend in average use per customer has been very stable since 2005. However, as with this sector in the small and large commercial customer segments, there are opportunities for efficiency improvements. TGI therefore projects a moderate decline in average use per customer over the forecast period.

19. Education

The Education sector consumed 17 per cent of the total natural gas that was consumed within the commercial transportation customer class in 2008. The following Figure C-4-17 illustrates the normalized annualized average use per customer over the period December 2005 through December 2008.

Figure C-4-17: Education sector – Stable since mid-2007

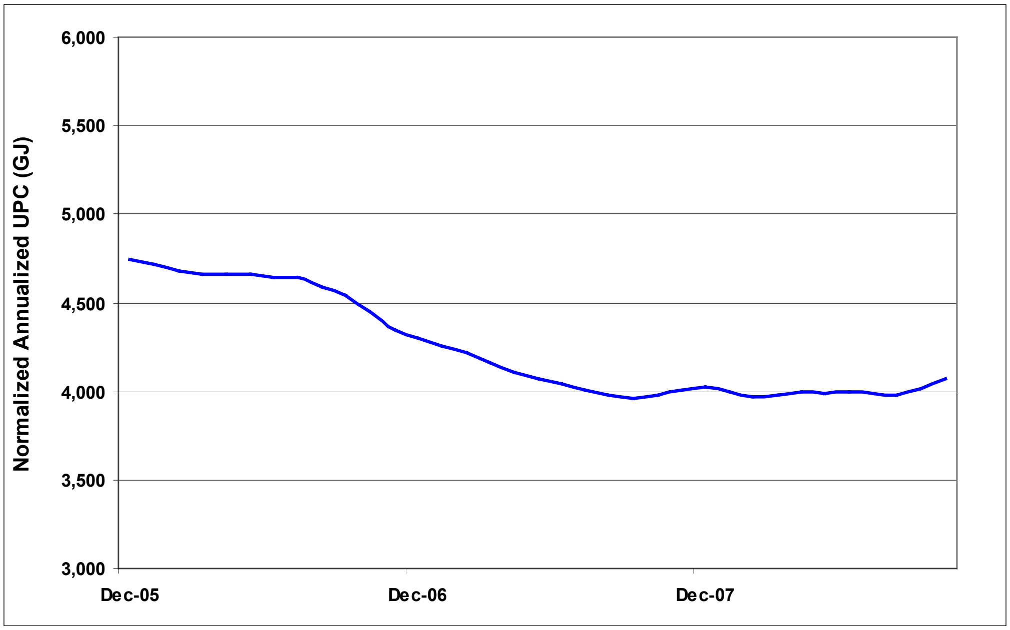


The Education sector within this customer segment includes larger schools, colleges and also universities. The average use per customer for this sector was relatively stable 2003 to 2005. Since rising in 2006 it has remained relatively stable again. As with this sector in the small commercial customer segment, TGI is projecting average use per customer to remain stable over the forecast period.

20. Government Building

The Government Building sector consumed 8 per cent of the total natural gas that was consumed within the commercial transportation customer class in 2008. The following Figure C-4-18 illustrates the normalized annualized average use per customer over the period December 2005 through December 2008.

Figure C-4-18: Government Buildings sector – Stable since 2007

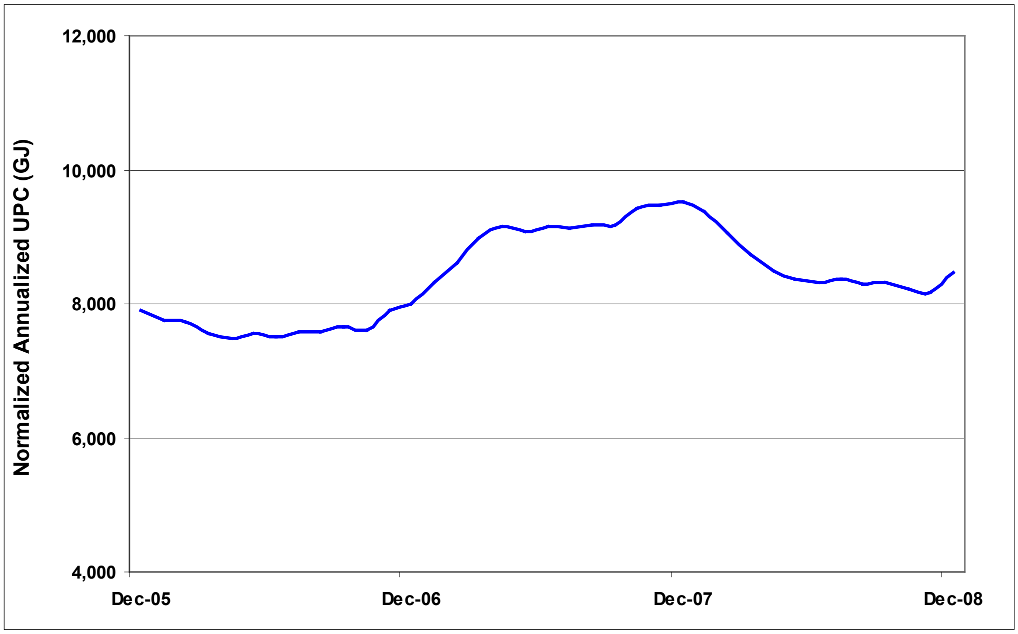


The average use per customer for this sector has been relatively stable over the past year and a half, after declining in previous years. There are likely to be further reductions in average use per customer in this sector, as a result of conservation efforts aimed at meeting the GHG targets outlined in the B.C. Energy Plan. TGI is projecting a moderate decline in average use per customer for this sector over the forecast period.

21. Greenhouse

The Greenhouse sector consumed 9 per cent of the total natural gas that was consumed within the commercial transportation customer class in 2008. The following Figure C-4-19 illustrates the normalized annualized average use per customer over the period December 2005 through December 2008.

Figure C-4-19: Greenhouse sector – More volatile due to fuel switching capabilities

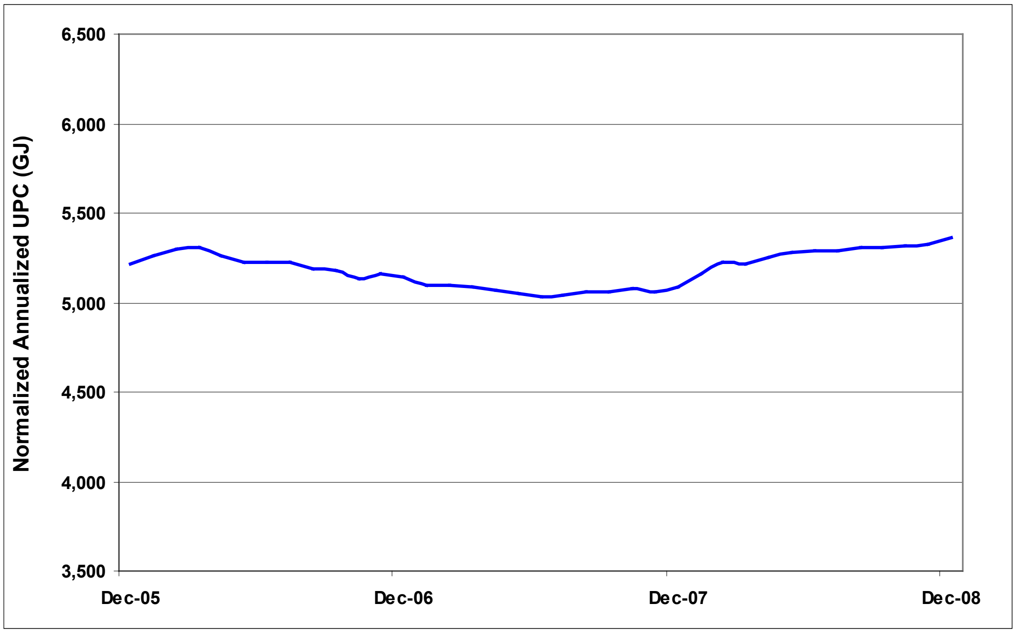


The average use per customer for this sector has shown some volatility since 2005, primarily because some of these customers have fuel switching capabilities and are therefore able to respond to fluctuations in the prices of both natural gas and alternative fuels. With the current price forecasts for natural gas remaining relatively low, TGI is assuming average use per customer will remain stable over the forecast period.

22. Wholesale/Retail

The Wholesale/Retail sector consumed 9 per cent of the total natural gas that was consumed within the commercial transportation customer class in 2008. The following Figure C-4-20 illustrates the normalized annualized average use per customer over the period December 2005 through December 2008.

Figure C-4-20: Wholesale/Retail sector – Relatively stable since early 2007

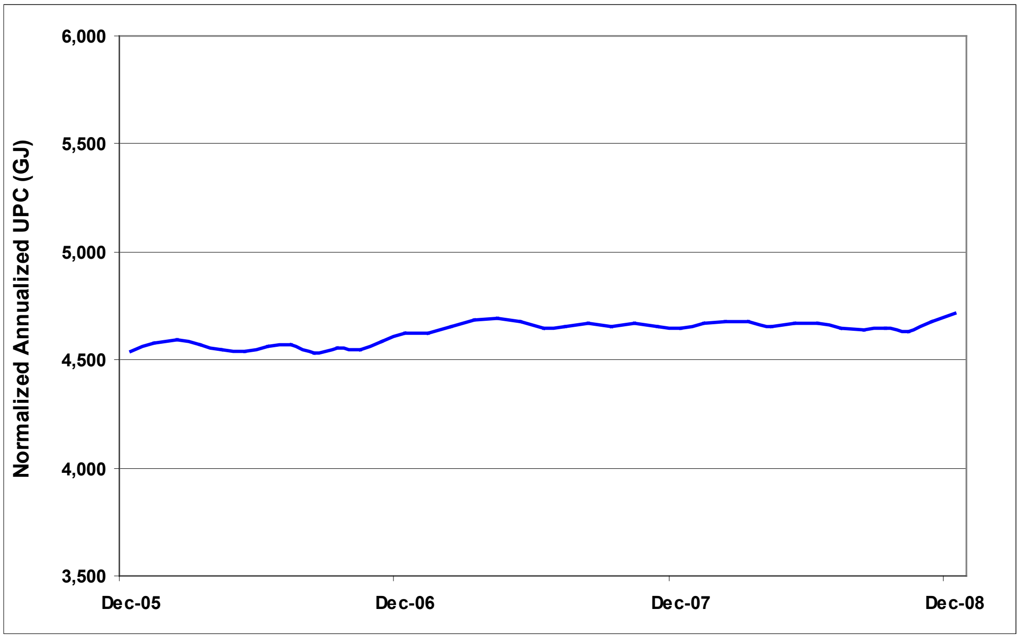


The Wholesale/Retail sector within this customer segment includes large retailers or wholesalers. The average use per customer for this sector declined over the period 2005 to 2007. Since trending upward during the first few months of 2008 it appears to have moderated since then. As with this sector for the small and large commercial customer segments, TGI is projecting average use per customer to remain stable over the forecast period.

23. Other

The "Other" sector is comprised of all industries other than those illustrated above and together they consumed 30 per cent of the total natural gas that was consumed within the commercial transportation (Rate 23) customer class in 2008. The following Figure C-4-21 illustrates the normalized annualized average use per customer over the period December 2005 through December 2008.

Figure C-4-21: Other sectors – Stable since early 2006



The "Other" sector within this customer segment experienced stable average use per customer throughout 2005 before increasing slightly in early 2006. Since then, average use per customer has again remained relatively stable. Given this, TGI is assuming average use per customer remains stable over the forecast period.

The above analyses have been incorporated into the overall forecast of average use per customer for each of the commercial customer classes. Table C-4-6 below provides a summary of the average use per customer for customers served under Rate Schedules 1 (and 1U), 2 (and 2U), 3 (and 3U), and 23 projected for 2009 and the forecast for 2010 and 2011.

Table C-4-6: Forecast Usage – Rate Schedules 1, 2, 3, & 23

	Projected 2009	Forecast 2010	Forecast 2011
Rate 1	94.6	89.7	88.3
Rate 2	323	318	318
Rate 3	3,427	3,346	3,346
Rate 23	4,830	4,680	4,680

Note: 2009 projections include three months of actuals (not weather normalized)

As described above, the forecast of average use per customer has been developed by analyzing historical consumption and considering efficiency improvements, trends in the market, customer migration, and also sector analyses for our commercial customers. This is consistent with the approach taken in prior years, is reasonable, and forms an appropriate basis for the determination of total energy demand for this RRA.

d) *Industrial Demand Forecast*

The forecast of industrial energy demand incorporates customer rate schedules 5, 7, 22, 25, and 27. Given the relatively small number of industrial customers, a different approach in forecasting demand is favoured over the approach taken for both residential and commercial customers. The methodology behind forecasting industrial energy demand is reasonable, and is typically derived from the following two sources:

- An annual customer information survey; and,
- Sector analyses of historical consumption.

e) *Customer Information Survey*

Typically, the primary source of information for the industrial energy forecast is the industrial customer survey, which is conducted over the period May through July on an annual basis. As the industrial customer survey will not be complete at the time of filing this RRA, it will be used as a secondary source of information.

Should there be a material difference between the forecast filed in the RRA and the results of the industrial customer survey, it is anticipated that an update will be filed as soon as practical.

f) *Sector Analyses*

Consistent with prior years, sector analyses have been completed for customers in those sectors identified as consuming a significant portion (more than 5 per cent) of the total industrial demand. Seven sectors were identified as having customers that represent more than 5 per cent of the total industrial volume. The historical consumption patterns of the customers in each of those seven sectors were analyzed and then used in conjunction with the latest available economic information to project future energy demand in each of those sectors. The result is a reasonable forecast that is appropriate for the determination of total energy demand for the RRA.

One of the challenges in forecasting industrial demand is the manner in which TGI's customers are segmented. TGI's rate classes are constructed to group customers with similar annual consumption patterns together, and then tariffs are developed to ensure each of the customer classes is paying their fair share of the costs associated with serving their energy requirements. Although this is appropriate, the challenge when forecasting natural gas demand is that customers in the same rate class are not necessarily impacted by the same factors. The Rate schedule 25 customer class, for example, has customers in the Wood Products sector that have seen their demand for natural gas significantly impacted by the ongoing economic hardships. In that same customer class there are customers in the health sector that continue to exhibit stable consumption patterns. There are also Apartments/Condominiums in that customer class which are showing similar trends as the residential customers. Generally speaking, there is a disparity in the factors affecting consumption by customers in particular customer classes, and therefore sector analyses not only make sense but add to the reasonableness of the forecast.

Through sector analyses, TGI is also able to incorporate sector specific factors influencing demand for natural gas. For example, many customers in the greenhouse sector have fuel switching capabilities and are able to take advantage of changes in the spot market for energy prices, whereas those capabilities are not present in other sectors. Customers in the Apartment/Condo sector have opportunities for efficiency improvements available to them that are not available to customers in other sectors. Although these sector specific factors present additional challenges when developing the industrial demand forecast, incorporating them further adds to its reasonableness.

The following Table C-4-7 illustrates the 2008 energy consumption and percentage each industry represents out of the total. The seven sectors being individually analyzed represent two-thirds of the total industrial volumes, providing a reasonable basis from which to develop the industrial demand forecast. The “other” category, representing one-third of the total industrial volumes, is also analyzed separately and includes a number of smaller industries such as education, commercial buildings, hotels, and recreation centres.

Table C-4-7: Industrial Customers Top Energy Consuming Sectors

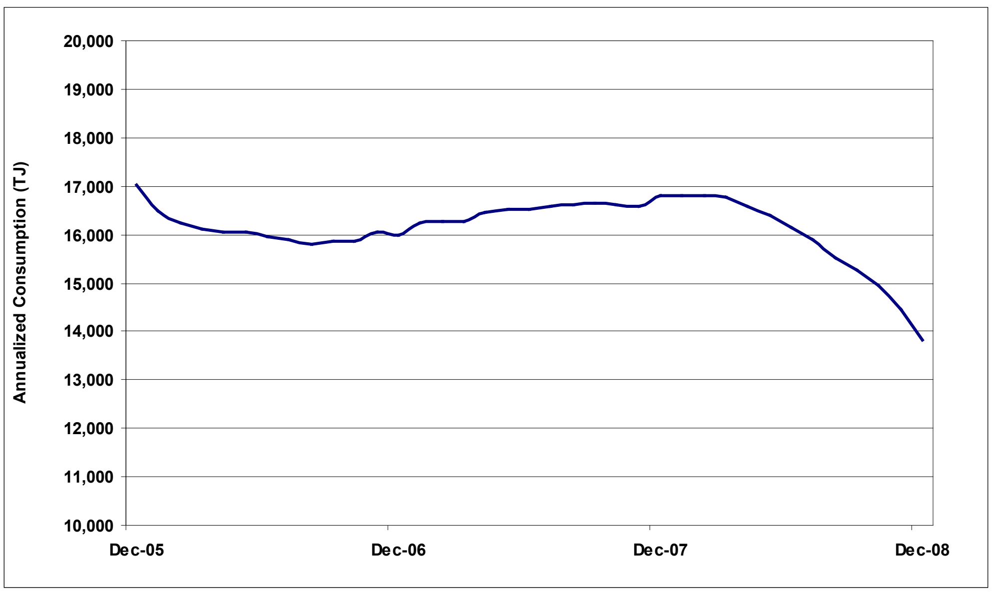
	PJs	%
Pulp & Paper	13.4	20%
Wood Products	5.9	8%
Greenhouses	3.6	6%
Mining	3.6	10%
Apartment/Condo	3.6	7%
Chemical Manufacturing	4.0	8%
Food & Beverage	3.5	7%
Other	14.2	34%
Total	**51.8**	**100%**

The above listed sectors are those for which sector analyses have been completed, historical consumption trends analyzed, and results have been validated against the most recent available economic information. The forecast of industrial demand is reasonable and appropriate for use in this RRA.

(a) Pulp and Paper

There are currently 22 industrial customers in the Pulp and Paper sector, and they represent approximately 20 per cent of the total industrial volumes. The following Figure C-4-22 illustrates the annualized consumption from December 2005 through December 2008.

Figure C-4-22: Pulp and Paper sector – Significant declines since early 2008

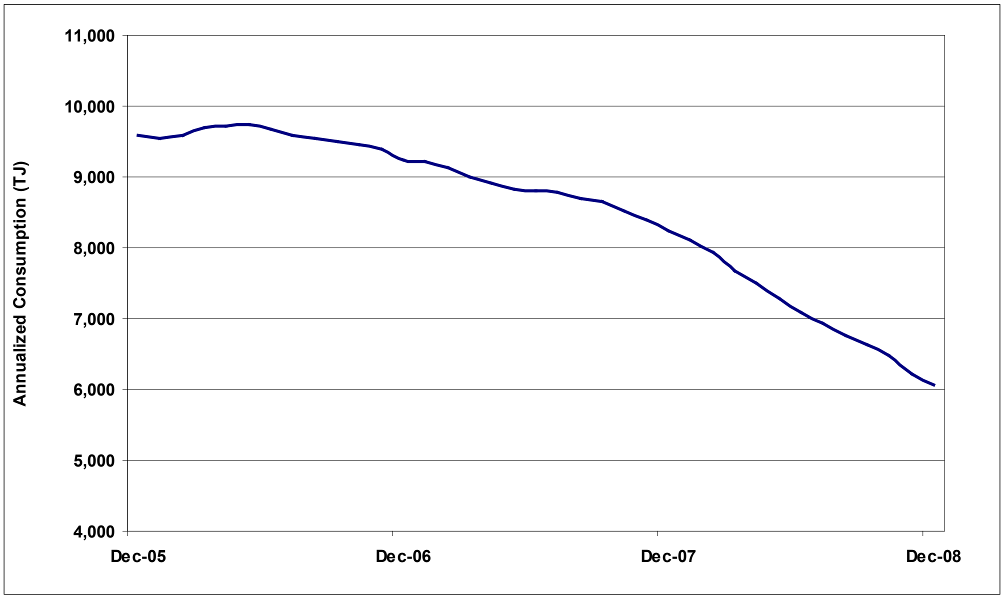


Consumption in the Pulp and Paper sector had been relatively stable up until approximately February 2008, when it began to significantly decline. Although there are a handful of customers that have experienced recent increases in annual consumption, those are not expected to continue. With the lack of growth, combined with continuing declining volumes for the remaining customers, consumption in this sector is projected to decline significantly in 2009 before beginning to stabilize in 2010 and 2011.

(b) Wood Products

There are currently 86 industrial customers in the Wood Products sector, and they represent approximately 8 per cent of the total industrial volumes. The following Figure C-4-23 illustrates the annualized consumption from December 2005 through December 2008.

Figure C-4-23: Wood Products sector – Significant declines since early 2006

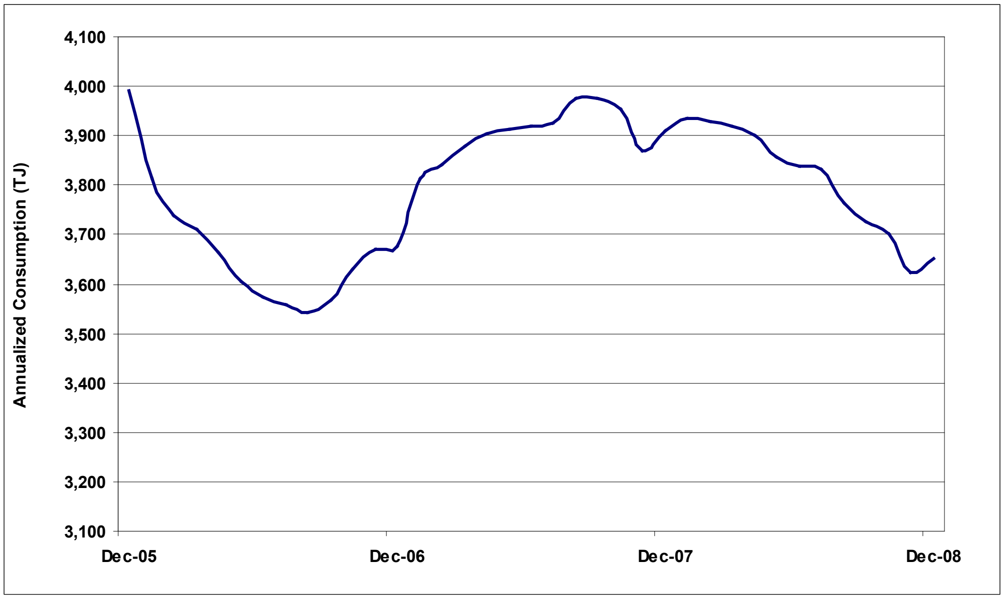


The Wood Products sector has seen steadily declining volumes since early 2006. With this sector being heavily dependant on the U.S. Housing market, a continued decline is anticipated. As with the Pulp and Paper sector, the projection for this sector is a significant decline in 2009, followed by a further decline in 2010 and then stabilizing in 2011.

(c) Greenhouses

There are currently 66 industrial customers in the Greenhouse sector, and they represent approximately 6 per cent of the total industrial volumes. The following Figure C-4-24 illustrates the annualized consumption from December 2005 through December 2008.

Figure C-4-24: Greenhouse sector – More volatile due to fuel switching capabilities

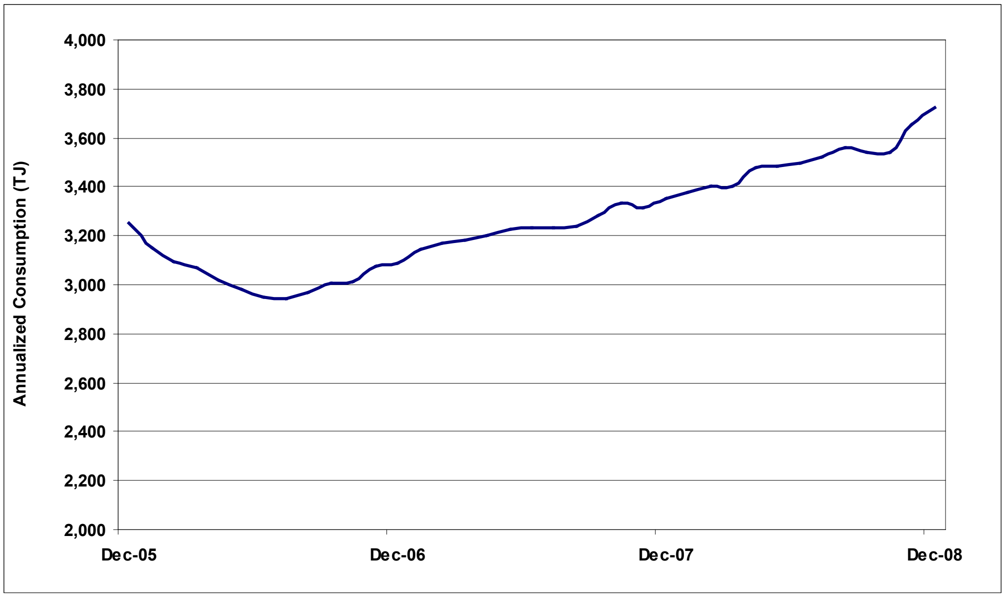


This sector has seen both declines and increases in volumes since 2005. Although the more recent trend is downward, there has been some growth experienced in this sector since December 2008. This sector has the capability to switch between fuel sources, and therefore tends to respond to conditions in the spot market, which presents a challenge when developing a forecast for this sector. Due to the adverse conditions the forestry industry is facing, there is a reduced supply of wood waste. In addition, given the fuel switching capability of this sector and the fact that natural gas prices are currently low, a number of customers in this sector have returned to natural gas from alternative energies to serve their energy needs. Considering the recent downward trend and the upside potential, TGI is projecting a 5 per cent decline in volumes for 2009, followed by very modest forecast of 1 per cent growth in both 2010 and 2011.

(d) Mining

There are currently 22 industrial customers in the Mining sector, and they represent approximately 10 per cent of the total industrial volumes. The following Figure C-4-25 illustrates the annualized consumption from December 2005 through December 2008.

Figure C-4-25: Mining sector – Trending upwards since late 2005

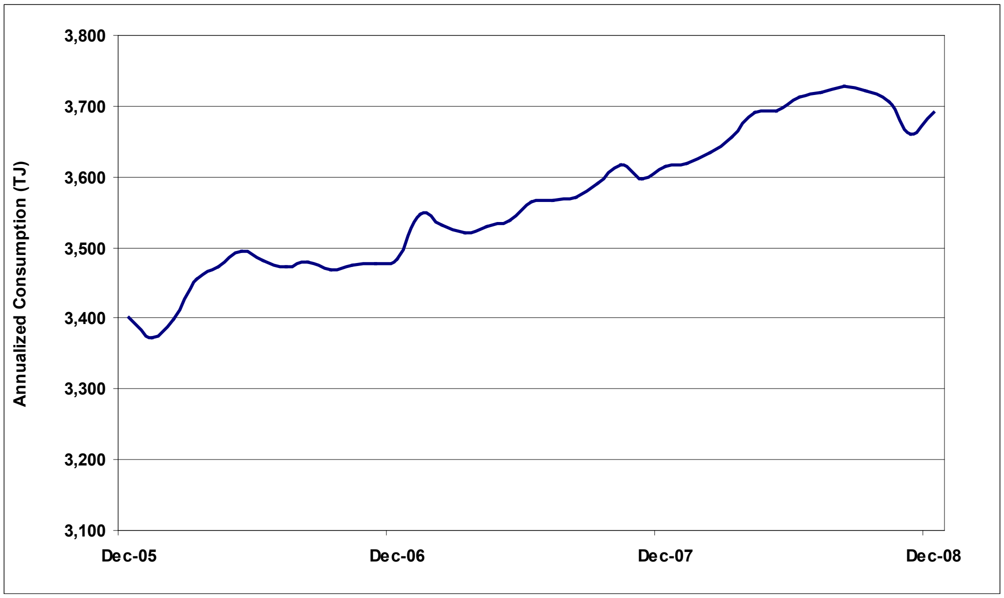


Demand for natural gas in the mining sector has been increasing over the past few years, even over the last half of 2008. Given there are relatively few customers in this sector, TGI's knowledge of these customers via prior survey responses and historical consumption, and also current economic conditions, TGI is projecting that annualized consumption will remain stable over the forecast period.

(e) Apartment/Condo

There are currently 324 industrial customers in the Apartment/Condo sector, and they represent approximately 7 per cent of the total industrial volumes. The following Figure C-4-26 illustrates the annualized consumption from December 2005 through December 2008.

Figure C-4-26: Apartment/Condo sector – Trending upward since early 2006

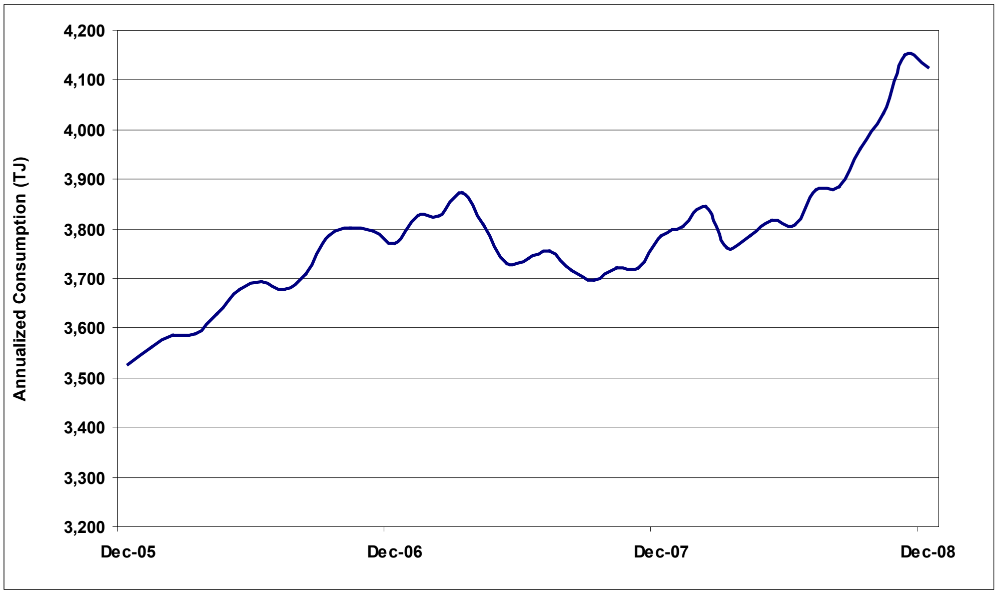


The Apartment/Condo sector represents larger apartment or condominium buildings, where natural gas consumption is high enough that it makes more economical sense for them to be in an industrial rate class. Although the trend since early 2006 has been upward for this sector, given these are residential customers, similar to the projections for this sector in the small and large commercial customer segments TGI is projecting a moderate decline in consumption throughout the forecast period.

(f) Chemical Manufacturing

There are currently 23 industrial customers in the Chemical Manufacturing sector, and they represent approximately 8 per cent of the total industrial volumes. The following Figure C-4-27 illustrates the annualized consumption from December 2005 through December 2008.

Figure C-4-27: Chemical Manufacturing sector – Variations due to fewer customers



This sector saw increasing volumes from 2005 through April 2007, where consumption then stabilized until the end of that year. The significant increase since then is a result of a single customer adding equipment during 2008 (which is now complete, and therefore is not expected to affect future demand). When analyzing consumption, excluding the single customer with significant growth, the more recent trend is downward. Given this, TGI is projecting a moderate decline in annual consumption for this sector over the forecast period.

(g) Food and Beverage

There are currently 77 industrial customers in the Food and Beverage sector, which represents approximately 7 per cent of the total industrial volumes. The following Figure C-4-28 illustrates the annualized consumption from December 2005 through December 2008.

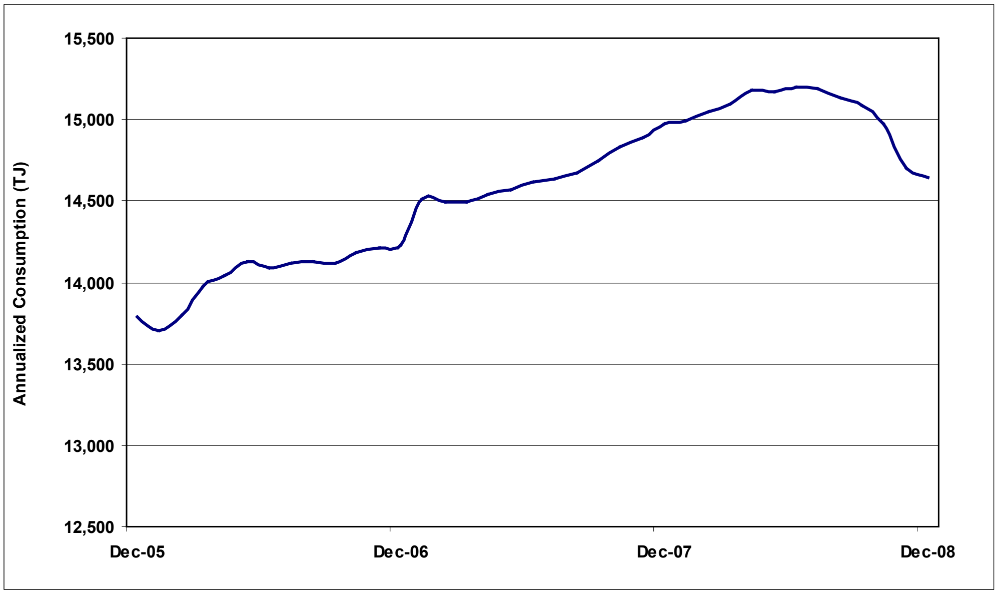
Figure C-4-28: Food and Beverage Manufacturing sector – Trending upward since 2007

Although this sector had been declining from 2005 through 2007, it has seen growth in 2008. These customers include breweries, bakeries, coffee producers, soft drink producers, and dairy producers, so incorporate a wide range of businesses which presents a challenge when forecasting demand. TGI's analysis indicates that the recent growth is due to a handful of customers, and further suggests that the growth seen in 2008 will likely not continue. Given the above, TGI is projecting stable annual consumption for this sector over the forecast period.

(h) All Other

There are currently 452 industrial customers in the "All Other" sector, which represents approximately 34 per cent of the total industrial volumes. The following Figure C-4-29 illustrates the annualized consumption from December 2005 through December 2008.

Figure C-4-29: Other sectors – Trending upward until mid-2008

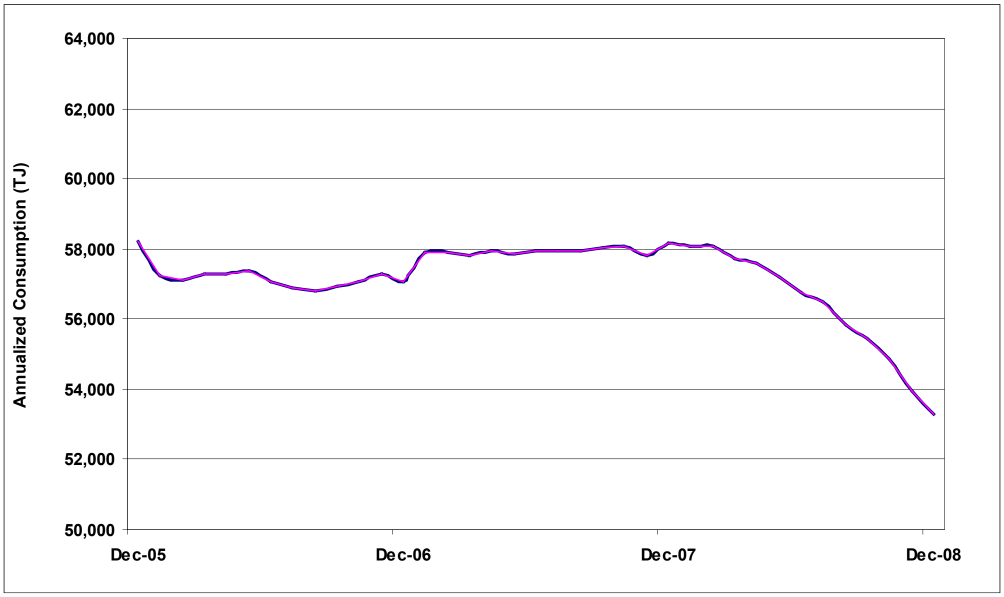


The “All Other” sector is comprised of smaller sectors such as education, commercial buildings, hotels, and recreation centres. Consumption had been steadily increasing for this group until about mid-2008, when it began declining. Based on its review of historical consumption, TGI is projecting a moderate decline in 2009 followed by a forecast of stable demand in both 2010 and 2011.

(i) Industrial Energy Forecast

The following Figure C-4-30 illustrates the annualized consumption for all industrial customers since 2005.

Figure C-4-30: All Industrial Customers – Downward trend since early 2008



As can be seen, volumes were relatively stable until early 2008, at which time significant declines occurred and resulted in an 8 per cent decline in volumes from 2007 levels. In considering the trends seen in the various sectors illustrated above, TGI is projecting a significant decline in 2009 followed by a further decline in 2010 before stabilizing in 2011. The forecast of industrial demand is appropriate and reasonable, as it includes an analysis of historical consumption, sector analyses, and also a review of the latest available economic data.

g) Energy Forecast for All Customer Rate Classes

The total energy forecast for all customer classes is expected to decline modestly over the forecast period, as customers continue seeking opportunities to improve efficiencies in their use of natural gas. The total energy forecast, for each customer class, is reasonable, based on methodologies consistent with prior years, and therefore appropriate for the RRA and use in the determination of rates over the forecast period. The customer classes are segmented into the following categories:

- Residential – Customer Rate Class 1;
- Commercial – Customer Rate Classes 2, 3, and 23;
- Firm Sales – Customer Rate Classes 4, 5, and 6; and
- Industrial – Customer Rate Classes 5, 7, 22, 25, and 27.

The following Table C-4-8 summarizes the projected natural gas consumption for 2009 and the forecast for 2010 and 2011.

Table C-4-8: Forecast Energy Consumption (PJs)[171]

	Projected 2009	Forecast 2010	Forecast 2011
Residential[1]	71.0	67.8	67.2
Commercial[2]	47.5	47.3	47.9
Firm Sales[3]	3.4	3.4	3.3
Industrial[4]	45.2	43.4	43.3
Total	**167.3**	**162.0**	**161.8**

Notes
1. Rate 1
2. Rates 2, 3 & 23
3. Rates 4, 5 & 6
4. Rates 7, 22, 25 & 27 (does not include Burrard Thermal & TGVI)

Note: 2009 projections include three months of actuals (not weather normalized)

h) *Margin and Revenue Forecast*

A reasonable forecast of revenues and margins has been developed by considering the total energy forecast, applicable rates, and the cost of gas.

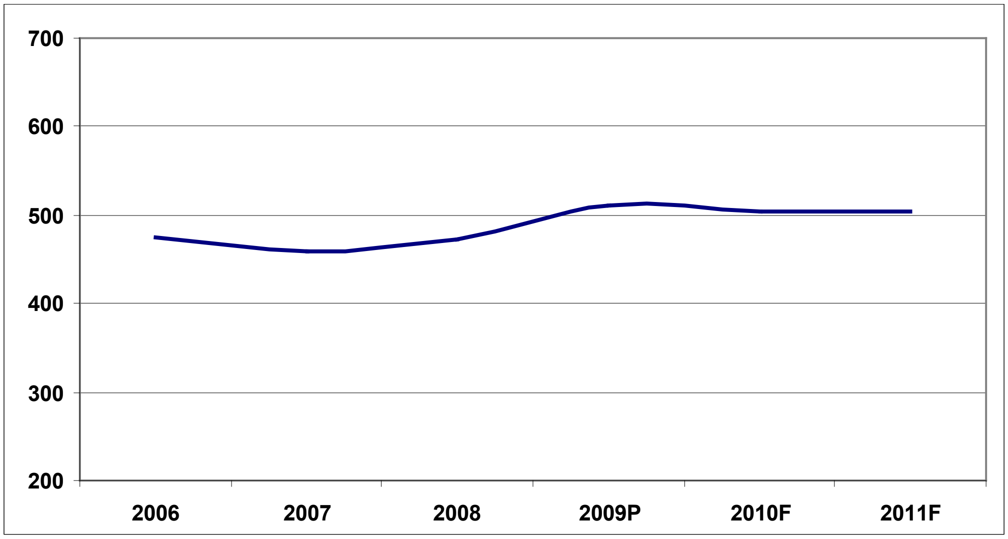
i) *Margins*

Margins are a function of both total revenues and the cost of natural gas being provided to customers. TGI has developed a reasonable forecast of margins by first developing the forecast of revenues and then subtracting from that the cost of natural gas.

The following Figure C-4-31 illustrates the historical margin over the period 2006 through 2008, the projection for 2009, and the forecast for 2010 and 2011.

[171] Part III, Section C, Tab 13, Schedules 14 & 15

Figure C-4-31: TGI Margin ($ million) – Relatively stable since 2006



As the above graph indicates, margins have been relatively stable since 2006, and are expected to remain so through the forecast period. The Table C-4-9 below summarizes the projected margin for 2009 and the forecast for 2010 and 2011, by customer segment.

Table C-4-9: Forecast Margin ($ million)[172]

	Projected 2009	Forecast 2010	Forecast 2011
Residential[1]	315.1	307.0	305.8
Commercial[2]	142.2	142.4	144.2
Firm Sales[3]	7.5	7.5	7.5
Industrial[4]	45.9	46.3	46.3
Total	**510.7**	**503.2**	**503.7**

Notes
1. Rate 1
2. Rates 2, 3 & 23
3. Rates 4, 5 & 6
4. Rates 7, 22, 25 & 27 (does not include Burrard Thermal & TGVI)

Note: 2009 projections include three months of actuals (not weather normalized)

Margins are comprised of both fixed and variable charges, and the portion each contributes varies for each customer segment. The margins for the residential and commercial customer segments have a smaller portion of fixed to variable charges (approximately 20 per cent fixed, 80 per cent variable) than

[172] Part III, Section C, Tab 13, Schedules 22-25

do the firm sales and industrial customer segments, where approximately 55 per cent of margins are fixed compared to 45 per cent variable. This means that the margin collected for residential and commercial customers is more influenced by annual fluctuations in consumption patterns than it is for firm sales and industrial customers. Similarly, it can be inferred that margins collected from firm sales and industrial customers, due to the nature of their contracts, are partially protected from yearly fluctuations in usage patterns.

j) Revenues

Revenues are a function of both energy consumption and the rate applicable at the time the energy is consumed. TGI has developed a reasonable forecast of revenues by applying the total energy forecast to the currently approved rates (as at January 1, 2009) for each customer class.

The revenue forecast presented in Table C-4-10 does not include amounts for TGVI and B.C. Hydro for Burrard Thermal. Those revenues are included in the financial schedules presented in Part III, Section C, Tab 14 Schedules 16 and 17 of the Application and reflect existing agreements.

The Table C-4-9 below summarizes the revenues projected for 2009 and forecast for 2010 and 2011, at 2009 rates.

Table C-4-10: Forecast Revenue ($ million)[173]

	Projected 2009	Forecast 2010	Forecast 2011
Residential[1]	883.5	897.4	891.8
Commercial[2]	478.5	503.6	511.1
Firm Sales[3]	32.1	29.9	29.7
Industrial[4]	47.5	47.1	47.0
Total	**1,441.5**	**1,478.0**	**1,479.5**

Notes
1. Rate 1
2. Rates 2, 3 & 23
3. Rates 4, 5 & 6
4. Rates 7, 22, 25 & 27 (does not include Burrard Thermal & TGVI)

Note: 2009 projections include three months of actuals (not weather normalized)

[173] Part III, Section C, Tab 13, Schedules 16 & 17, Line 28, less Line 21 Column (5)

k) Other Revenue

(a) Burrard Thermal

Various Burrard Thermal agreements, including the Bypass Transportation Agreement, are forecasted to provide $10 million[174] in revenues in 2010 and 2011. The transportation charge is fixed and independent of energy consumption.

(b) TGVI

Revenue from wheeling demand charges and odorant cost recovery is approximately $3.5 million[175] for 2010 and 2011. These revenues are based upon the specified rates included in the Wheeling agreement, which has been approved by the Commission.

(c) Southern Crossing Pipeline

For 2010, SCP Third Party firm revenues are forecast to be $12.8 million and $14.8 million for 2011. The Table C-4-11 below illustrates the detailed revenue forecast for SCP.

Table C-4-11: Southern Crossing Pipeline Revenues[176]

	2009	2010	2011
Northwest Natural Gas Co.	$ 7,297,102	$ 7,580,692	$ 8,993,991
PG&E Termination	$ (825,000)	$ (711,667)	$ (145,000)
MCRA	$ 3,600,000	$ 3,600,000	$ 3,600,000
Motor Fuel Tax	$ (50,000)	$ (50,000)	$ (50,000)
Net Mitigation	$ 1,000,000	$ 2,400,000	$ 2,400,000
Total SCP Revenues	**$ 11,022,102**	**$ 12,819,025**	**$ 14,798,991**

Terasen Gas has a firm service contract with Northwest Natural Gas, approved in order G-98-05, for 46.5 MMcfd of SCP capacity over the period November 2004 through October 2020. PG&E Termination fees will decrease from $825,000 per year to $145,000 per year, effective November 1, 2010.

The revenue of $3.6 million per year is related to the inclusion of SCP capacity in the Midstream (MCRA) portfolio. At the time SCP was first put in service in December 2000, the Company had entered into a Transportation Service Agreement and Peaking Gas Purchase Agreement with BC Hydro (the "BC Hydro Agreements") based on 52.2 MMcfd of SCP capacity. The initial term of the agreements expired

174 Part III, Section C, Tab 13, Schedules 26 & 27
175 Ibid
176 Ibid

November 1, 2010, although BC Hydro held the option to extend the term for a maximum of an additional 10 years (i.e. to November 1, 2020). The arrangements with BC Hydro also permitted BC Hydro to assign the agreements to Terasen Inc by giving 13.5 months notice (the "Put Option").

In 2004, BC Hydro exercised its Put Option to assign the agreements to Terasen effective November 1, 2005. By Order Number G-98-05 dated October 5, 2005, the Commission subsequently approved an application by the Company to terminate the BC Hydro Agreements and for the inclusion of the 52.2 MMcfd of SCP capacity in the Midstream portfolio along with corresponding adjustments to other peaking and transportation capacity resources in a manner that optimizes the portfolio. The Commission also approved an annual allocation of $3.6 million to be debited against the MCRA, with an equal and offsetting allocation to be credited to the delivery margin revenue account for the period ending November 1, 2010, corresponding to the primary term under the former BC Hydro Agreements. Under the approved arrangements, Midstream effectively holds the SCP Capacity previously held by BC Hydro and replaces the BC Hydro TSA revenues that were credited against the delivery margin revenue account.

As the approval of the $3.6 million per year debiting of the MCRA and crediting of the delivery margin revenue account extends until November 1, 2010, part way through the effective term of this Application, Terasen Gas hereby seeks approval from the Commission to extend the continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year by a period of ten years until November 1, 2020. Terasen Gas believes this treatment of costs and revenues is fair and appropriate given that SCP capacity is now an essential part of its midstream portfolio, meeting the objectives of safe, reliable and cost-effective resources, and continues to provide optimal benefits to customers. As such, the debit to the Midstream Cost Reconciliation Account, currently expiring November 1, 2010, has been extended through 2011 as discussed in the Cost of Gas section of this application in Part III, Section C, Tab 5.

Net mitigation revenues are forecast at $2.4 million per year in 2010 and 2011, an increase of $1.4 million per year from the previously forecast amount of $1 million per year. The change in net mitigation revenue reflects changing market conditions with regards to TGI's mitigation efforts in purchasing Station 2 and selling Huntingdon, purchasing Station 2 and selling Kingsgate, and also purchasing AECO and selling Huntingdon. All SCP revenues other than motor fuel tax are fixed in nature and independent of energy consumption.

(d) Miscellaneous Revenue

Revenue from service work will reduce to $25 from $85 for customer additions (as discussed in Part III, Section C, Tab 12) and remain at $25 for account transfers. Late Payment Charges, as stated in the tariff, are charged at a rate of 1.5 per cent per month, and are estimated annually based on prior year's experience. Annual NSF cheques are estimated at approximately 0.5 per cent of the beginning of year's account base at a rate of $20 per cheque, in accordance with the tariff

Other miscellaneous revenue is estimated at approximately $74,000 in 2010 and $75,500 in 2011[177], comprising of Non-Regulated Businesses (NRB) recoveries.

I) Summary

Through considering the factors influencing customer additions, average use per customer, and also industrial volumes TGI has developed a forecast of demand for natural gas. The economic turmoil and dramatic decline in the housing market will lead to a decline in customer additions. At the same time, as customers continue to look for ways in which to improve efficiencies, average use per customer will also decline. The industrial sector analyses indicated that, although different sectors can be expected to grow at different rates, overall industrial volumes will decline in the near future. It is through considering these factors, applying a methodology consistent with prior years, and by using the latest and best information available that TGI believes it has developed a reasonable demand forecast that is the most appropriate to be used in the determination of rates for the 2010 and 2011 forecast period.

[177] Part III, Section C, Tab 13, Schedules 26 & 27

5. Cost of Gas

For the 2010 and 2011 forecast period, the total cost of gas sold is comprised of the commodity and the midstream components, and is determined by multiplying forecast sales volumes by the approved forecast unit gas costs for each rate schedule. The commodity unit costs for natural gas sales rate customers and the midstream unit costs for the natural gas sales rate customers are reviewed and approved by the Commission, and Terasen Gas is not requesting approval of forecast gas costs with this Application, however forecast gas cost are required in the determination of a number of revenue requirement line items.

Any rate changes related to the “flow-through” of gas costs are dealt with in separate applications to the Commission. Terasen Gas will continue to report gas costs on a quarterly basis, as required under the Commission Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Account Balance (Commission Letter No. L-05-01, dated February 5, 2001), and make application for “flow-through” rate changes on a basis consistent with established practice and the Commission guidelines. The 2010 gas cost rates to be effective January 1, 2010 will not be known until after the Commission reviews the Terasen Gas 2009 Fourth Quarter Gas Cost reports which are anticipated to be filed in late November or early December 2009.

The 2009 First Quarter Gas Cost reports were filed in early March 2009, and, as approved by Commission Order No. G-23-09 and Order No. G-24-09, both the Terasen Gas commodity recovery rate and the Revelstoke propane cost recovery rate were decreased effective April 1, 2009. Further, the 2009 Second Quarter Gas Cost reports were filed in early June 2009, and included proposals for no change to the Terasen Gas commodity recovery rate effective July 1, 2009 but an increase to the Revelstoke propane cost recovery rate effective July 1, 2009.

a) Gas Cost Deferral Mechanisms

Gas cost related deferral accounts decrease the volatility in rates caused by fluctuations in gas prices thereby providing greater rate stability for customers. The various gas cost deferral accounts capture variances between the actual gas costs and the forecast gas costs as recovered in rates, and the deferral mechanisms in place allow these variances to be recovered from, or refunded to, customers as part of future rates. Terasen Gas, within Part III, Section C, Tab 8 of this Application, has requested Commission approval for the continuation of various Margin Related Deferral Accounts, including the three gas cost deferral accounts; the Commodity Cost Reconciliation Account, the Midstream Cost Reconciliation Account, and the Revelstoke Propane Cost Deferral Account.

b) Commodity and Midstream Cost Reconciliation Accounts

With the implementation of the Essential Services Model and the Commercial Commodity Unbundling Program, use of the GCRA was discontinued as of March 31, 2004[178]. The two new gas cost related deferral accounts, the CCRA and the MCRA, became effective April 1, 2004. At that time, the March 31, 2004 closing balance within the GCRA was transferred to the MCRA.

The CCRA captures the costs incurred by Terasen Gas to purchase its portion of the baseload commodity supply under the Essential Services Model and the commodity cost recovery rate revenues received from sales customers choosing to remain on the utility standard rate offering. Commodity price-related variances collected in the CCRA are taken into account when determining future commodity rate changes. Commodity rates are reviewed on a quarterly basis, and typically reset when the commodity recovery-to-cost ratio, on a 12-month prospective basis, falls outside the 0.95 to 1.05 threshold. Generally, when commodity rates are reset, the new rate is designed to recover, or refund, over the next 12 months any existing CCRA account balance, along with any under or over recovery of commodity costs forecast to occur over the next 12-month period.

The MCRA captures the costs the Company incurs in performing the midstream function and the revenues collected by Terasen Gas through midstream rates. In its midstream role, the Company uses the pipeline and storage resources, spot and peaking purchases, and sale activities as approved in the Annual Contracting Plan to manage load variability. The MCRA accumulates any resultant cost variances, including any volume-related variances due to differences between the forecast and actual consumption. The resulting variances are taken into account when determining future midstream rates. Midstream rates are reviewed on a quarterly basis and, under normal circumstances, midstream rates are adjusted on an annual basis with a January 1 effective date. Generally, when midstream rates are reset for the upcoming calendar year, the new rate is designed to recover, or refund, over the next 12 months any existing MCRA account balance, along with any under or over recovery of midstream costs forecast to occur over the next 12-month period.

c) Revelstoke Propane Cost Deferral Account

The Revelstoke Propane Cost Deferral Account, approved by Commission Order No. G-72-90, dated October 9, 1990, captures the difference between the actual cost of propane and the amount recovered in rates, based on the approved reference price of propane. The propane reference price is reviewed on a quarterly basis, and typically reset when the propane recovery-to-cost ratio, on a 12-month prospective basis, falls outside the 0.95 to 1.05 threshold. In general, when the propane reference price

[178] As approved by Commission Order No. G-25-04, dated March 12, 2004

is reset, the new reference price is designed to recover, or refund, over the next 12 months any existing deferral account balance, along with any under or over recovery of propane costs forecast to occur over the next 12-month period.

d) Unaccounted For Gas

Unaccounted for gas ("UAF") refers to gas that is not specifically accounted for in gas energy balance of receipts, deliveries, and operations use. UAF includes measurement variances and cannot be projected with precision.

Consistent with past practice, the UAF percentages are calculated based on the historical five-year rolling average UAF percentage for each service area. The cost of UAF related to the Sales rate classes is included in the MCRA and recovered via the midstream rate. The cost of UAF related to Transportation Service rate classes is included in the cost of service and the determination of delivery rates.

e) Treatment of Costs within the MCRA Related to Southern Crossing Pipeline ("SCP")

At the time SCP was first put in service in December 2000, the Company had entered into a Transportation Service Agreement and Peaking Gas Purchase Agreement with BC Hydro (the "BC Hydro Agreements") based on 52.2 MMcfd of SCP capacity. The initial term of the agreements expires November 1, 2010, although BC Hydro held the option to extend the term for a maximum of an additional 10 years (i.e. to November 1, 2020). The arrangements with BC Hydro also permitted BC Hydro to assign the agreements to Terasen Inc by giving 13.5 months notice (the "Put Option").

In 2004, BC Hydro exercised its Put Option to assign the agreements to Terasen effective November 1, 2005. By Order No. G-98-05 dated October 5, 2005, the Commission subsequently approved an application by the Company to terminate the BC Hydro Agreements and for the inclusion of the 52.2 MMcfd of SCP capacity in the Midstream portfolio along with corresponding adjustments to other peaking and transportation capacity resources in a manner that optimizes the portfolio. The Commission also approved an annual allocation of $3.6 million to be debited against the MCRA with an equal and offsetting allocation to be credited to the delivery margin revenue account for the period ending November 1, 2010, corresponding to the primary term under the former BC Hydro Agreements. Under the approved arrangements, the Midstream portfolio effectively holds the SCP Capacity previously held by BC Hydro and replaces the BC Hydro TSA revenues that were credited against delivery margin revenue account.

The approval of the $3.6 million per year debiting of the MCRA and crediting of the delivery margin revenue account extends until November 1, 2010, which is part way through the effective term of this

Revenue Requirement Application. Terasen Gas is therefore seeking approval from the Commission to extend the continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year by a period of ten years until November 1, 2020 as requested in Part III, Section C, Tab 4, Other Revenue on page 314. Terasen Gas believes this treatment of costs and revenues is fair and appropriate given that SCP capacity is an essential part of its midstream portfolio, meeting the objectives of safe, reliable and cost effective resources, and continues to provide optimal benefits to customers.

f) Company Use Gas

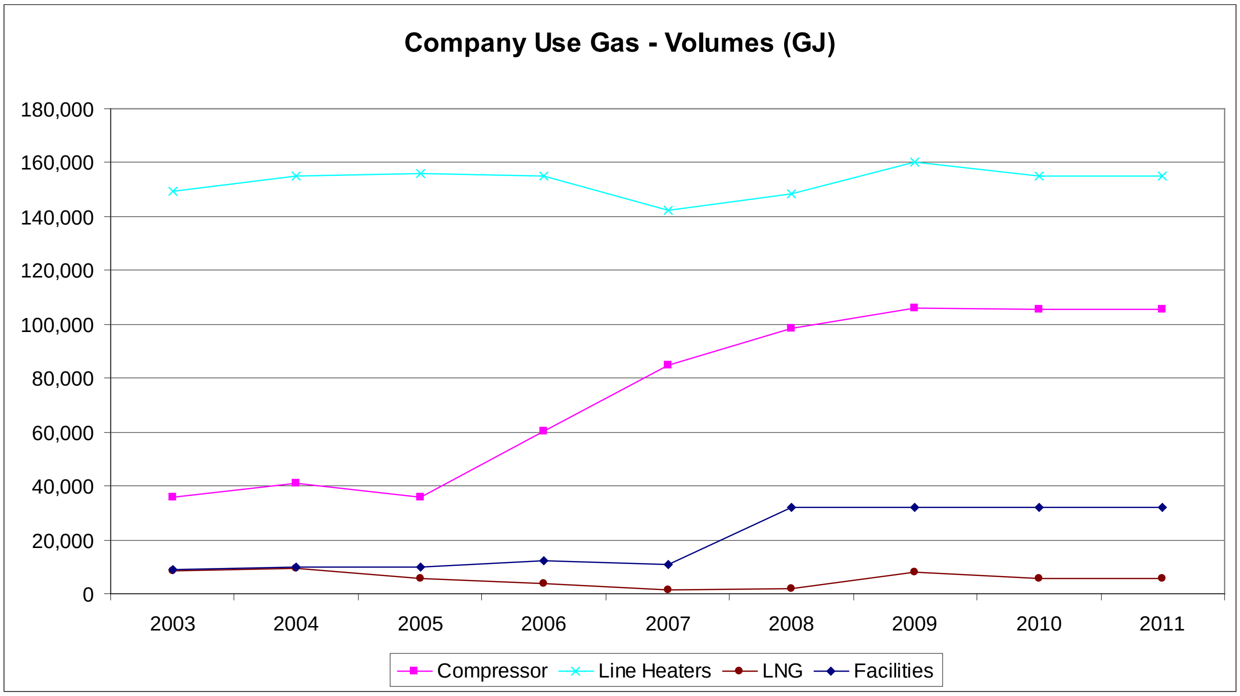
Company gas use, or "own use fuel", is required to deliver natural gas to customers in a safe and efficient manner and it represents a significant cost for Transmission, Distribution and Facilities operations. Terasen Gas company use gas is consumed as Distribution line heater fuel, Transmission compressor fuel and LNG plant fuel as well as gas used in Terasen Gas facilities and offices. Volumes used over the PBR Period have been in line with the assessed volumes under the PBR Agreement, but prices have significantly increased. Terasen Gas is proposing and seeking approval from the Commission for a revised costing and volume variance methodology for company use gas going forward as part of this Revenue Requirements Application and this section will discuss this methodology and why Terasen Gas believes it to be appropriate.

(1) VOLUMES

To date, variances between actual and forecast company use gas volumes have been managed within the O&M costs. Going forward for 2010 and 2011, Terasen Gas proposes to modify this methodology of accounting for volume variances, whereby the O&M expense would be booked based on the forecast volume and the MCRA would absorb any volumes not used or excess volumes required for company use gas. Any excess volumes remaining in the MCRA will be used for core load purposes if required or sold off in the marketplace and recovered as mitigation revenues for core customers. If greater volumes than forecast are required for company use gas, the MCRA will provide these additional volumes through its current supply portfolio or incremental spot purchases as currently is typically done when core load requirements exceed forecasts. Actual company use gas volumes will differ from forecast primarily due to changes in weather, core load requirements and pipeline operating conditions. Terasen Gas therefore believes that accounting for volume variances within the MCRA is consistent with the purpose of the MCRA in managing core load fluctuations.

The volumes used in the operations of the Transmission, Distribution and Facilities departments to develop their company use gas O&M budgets have been based on historic actual usage, subject to a high-level normalization adjustment for weather. The following figure shows the historical actuals, projected and forecast company use gas volumes.

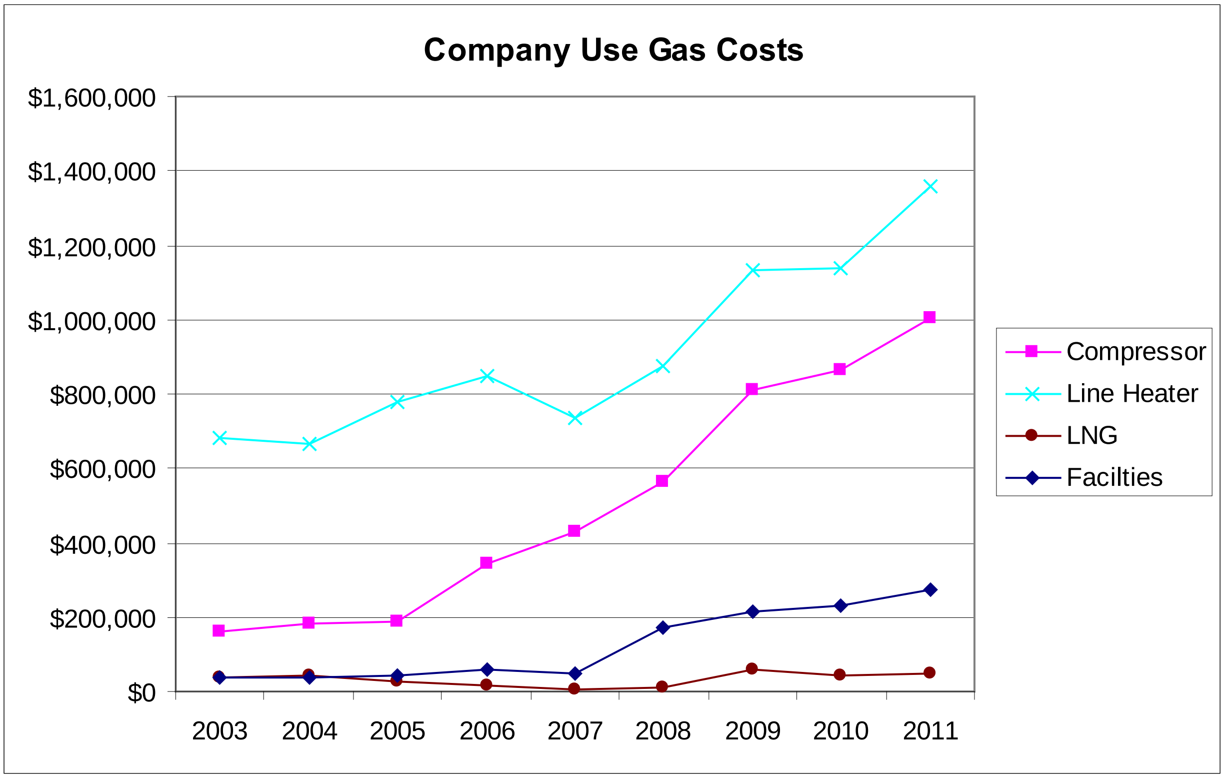
Figure C-5-1: Company Use Gas Volumes



(a) Historical Unit Costs

Over the PBR Period costs have dramatically escalated as shown in the following graph. The primary reasons for this are increases in the price of natural gas over time, increases in total volumes of company use gas consumed, the introduction of new taxes and changes in the pricing methodology as detailed in the following sections and the O&M expenditures sections of this Application.

Figure C-5-2: Company Use Gas Costs have increased Substantially and are Expected to Continue to Increase



(b) Proposed Changes in Pricing Methodology

Historically, the unit cost of company use gas has been based on the pricing methodology associated with gas supply contracts, referred to as '70/30 netback gas purchase contracts' ("netback contracts"), with a delivery point of Huntingdon. The 70/30 pricing mechanism was developed before significant trading volumes occurred at the Huntingdon market hub. The pricing in these supply contracts was designed to separate out the fixed, or monthly demand charge, component from the variable, or commodity charge, component of moving gas from the wellhead location in northern B.C. to the delivery point at Huntingdon. Prior to the ability to resell gas at Huntingdon readily, it was necessary to have a means of compensating the supplier for their fixed costs (related to pipeline tolls) should a gas contract be shut in due to lack of demand (i.e. the supplier could not find a buyer at Huntingdon). The cost of company use gas was based on the variable portion of this netback contract methodology. In theory, approximately 70 per cent of the invoice price related to variable charges and the remaining 30 per cent related to fixed demand charges. This ratio, however, was often different depending on the change in demand tolls and commodity prices over time. In the past, Terasen Gas purchased a portion of its Huntingdon supply from producers based on this netback contract methodology. As the natural gas marketplace evolved and the Huntingdon hub with associated Sumas pricing became a more liquid market, these netback contracts were no longer used by producers, with the last of Terasen Gas' remaining netback contracts expiring on October 31, 2006.

To date, Terasen Gas has calculated the cost of company use gas based on the variable portion of the netback contracts methodology. In the 2003 Revenue Requirement, Terasen Gas sought to make the change to the pricing methodology due to decline in the amount of gas Terasen Gas had purchased under the netback contracts. However, the Commission decision with respect to the Terasen Gas 2003 Revenue Requirements dated February 4, 2003 stated that "the Commission considers that company use gas forecasts that include both fixed and variable aspects of price are inconsistent with the basis on which the Utility pays for this gas". With the extension of the PBR Period, Terasen Gas advised the Commission in a letter dated October 31, 2006[179] that it would continue to use the netback contract variable pricing methodology for costing company use gas until the end of the PBR Period.

Going forward, Terasen Gas believes that the netback contract pricing methodology is no longer applicable or relevant in today's index-based marketplace[180]. Instead, Terasen Gas proposes that the natural gas industry Sumas price for Huntingdon gas should be used to forecast the cost of company use gas for 2010 and 2011. Terasen Gas believes that the Sumas pricing at the Huntingdon market hub is a reasonable and appropriate proxy and is representative of where the gas is ultimately delivered for consumption. As such, Terasen Gas requests approval from the Commission for the new pricing methodology as described.

Given the volatility in the natural gas marketplace in recent years, Terasen Gas believes it prudent and appropriate to continue to hedge the pricing associated with company use gas through Sumas fixed price swaps to provide protection against possible unfavourable movements in natural gas prices in the future. Terasen Gas, as requested within its letter to the Commission dated May 29, 2009, recommended and sought approval for the use of a hedge, based on the Sumas price and the forecast volumes, for all company use gas for the term of the Revenue Requirement. At the time of preparing this RRA application, the Company has not yet received approval for the recommended hedging. However, at the time approval is received, a hedge will be entered into based on the forecasted volumes for 2010 and 2011. As such, the forecasted company use gas costs, as represented in this section and in the relevant O&M sections of this Application, are based on current forward market prices. Hedging the company use gas for 2010 and 2011 will provide greater certainty around these O&M expenditures and also protect costs from escalating significantly if natural gas prices rise in the future.

[179] Acknowledged by the Commission in a letter dated November 14, 2006 per Log No. 16635

[180] The trading market for natural gas has evolved to treat costs of natural gas as 100 per cent commodity versus a mixture of fixed and variable costs.

(c) Volume Variances Managed within the MCRA

Currently, variances between actual and forecast company use gas volumes are managed within the O&M costs, whereby the forecast company use gas volumes are initially recorded against the MCRA. On a monthly basis, the volumes are then transferred to the appropriate TGI operating and maintenance accounts based on the actual volumes consumed. In other words, the O&M expenses absorb any volume variances between forecast and actual.

Going forward for 2010 and 2011, TGI recommends and requests Commission approval to modify the current methodology of accounting for volume variances, so that O&M costs would no longer be adjusted for the actual volumes consumed. Instead, TGI proposes to use the MCRA to absorb any volumes not used or excess volumes required for company use gas. According to this proposal, any excess volumes remaining in the MCRA would be used for core load purposes, if required, or sold off in the marketplace and recovered as mitigation revenues for core customers. If greater volumes than forecast are required for company use gas, the MCRA would provide these additional volumes through its current supply portfolio or incremental spot purchases as is typically now done when core load requirements exceed forecasts.

Actual company use gas volumes may differ from forecast primarily due to changes in weather, core load requirements and pipeline operating conditions. TGI therefore believes that accounting for volume variances within the MCRA is consistent with the purpose of the MCRA which is to manage seasonal core load fluctuations.

Terasen Gas therefore requests approval from the Commission for this methodology of accounting for volume and cost variances within the MCRA account effective January 1, 2010.

(d) New Taxes: Carbon Tax and Innovative Clean Energy ("ICE") Levy

Since 2003, two new taxes have been introduced and are anticipated to continue through the Revenue Requirement period. The carbon tax, introduced effective July 2008 increases by approximately \$0.25/GJ each year until 2012 when it will reach \$1.50/GJ and the Innovative Clean Energy Levy tax represents 0.4 per cent applicable to the unit pricing. These taxes, along with provincial sales tax and motor fuel tax have been applied to company own use fuel costs where appropriate.

(e) Forecast Unit Costs

Based on the revised pricing methodology and new taxes previously discussed, the forecast unit costs for company use gas are presented in the following table. The O&M expenditures for the Distribution, Transmission and Facilities departments related to company use gas, as presented in the O&M sections of this Application, are reflective of these unit costs and forecast volumes.

Table C-5-1: Company Use Gas Unit Costs[181] ($/GJ)

Month	Sumas Forward Price	PST	Fuel Tax	ICE Levy	Carbon Tax	Unit Cost LNG, Line Heater & Facilities *	Unit Cost Compressors **
Jan-10	$6.50	7%	$0.60	0.40%	$0.7449	$7.73	$7.85
Feb-10	$6.56	7%	$0.60	0.40%	$0.7449	$7.79	$7.90
Mar-10	$5.65	7%	$0.60	0.40%	$0.7449	$6.82	$7.00
Apr-10	$5.26	7%	$0.60	0.40%	$0.7449	$6.39	$6.60
May-10	$5.31	7%	$0.60	0.40%	$0.7449	$6.45	$6.65
Jun-10	$5.43	7%	$0.60	0.40%	$0.7449	$6.57	$6.77
Jul-10	$5.56	7%	$0.60	0.40%	$0.9932	$6.96	$7.15
Aug-10	$5.66	7%	$0.60	0.40%	$0.9932	$7.07	$7.25
Sep-10	$5.71	7%	$0.60	0.40%	$0.9932	$7.13	$7.30
Oct-10	$5.81	7%	$0.60	0.40%	$0.9932	$7.23	$7.40
Nov-10	$6.43	7%	$0.60	0.40%	$0.9932	$7.90	$8.03
Dec-10	$7.72	7%	$0.60	0.40%	$0.9932	$9.29	$9.32
Jan-11	$7.97	7%	$0.60	0.40%	$0.9932	$9.55	$9.56
Feb-11	$7.96	7%	$0.60	0.40%	$0.9932	$9.54	$9.55
Mar-11	$6.92	7%	$0.60	0.40%	$0.9932	$8.43	$8.51
Apr-11	$6.26	7%	$0.60	0.40%	$0.9932	$7.71	$7.85
May-11	$6.25	7%	$0.60	0.40%	$0.9932	$7.70	$7.84
Jun-11	$6.33	7%	$0.60	0.40%	$0.9932	$7.80	$7.93
Jul-11	$6.45	7%	$0.60	0.40%	$1.2415	$8.16	$8.29
Aug-11	$6.53	7%	$0.60	0.40%	$1.2415	$8.25	$8.37
Sep-11	$6.56	7%	$0.60	0.40%	$1.2415	$8.28	$8.40
Oct-11	$6.65	7%	$0.60	0.40%	$1.2415	$8.38	$8.49
Nov-11	$7.17	7%	$0.60	0.40%	$1.2415	$8.94	$9.01
Dec-11	$8.33	7%	$0.60	0.40%	$1.2415	$10.18	$10.17

* includes PST, ICE Levy and Carbon Tax

** includes Fuel Tax and Carbon Tax

[181] These numbers are subject to change as the proposed hedge transaction has not yet occurred.

(f) Company Use Gas Summary

Terasen Gas company gas use, or own use fuel, is required to deliver natural gas to customers in a safe and efficient manner and represents a significant cost for Transmission, Distribution and Facilities operations. With the expiration of the 'netback' contracts and the change to an index-based market, Terasen Gas believes that it is appropriate to use a new pricing methodology based on the Sumas index for company use gas costs for 2010 and 2011. Furthermore, as actual company use gas volumes may differ from forecast primarily due to changes in weather, core load requirements and pipeline operating conditions, Terasen Gas believes accounting for volume variances within the MCRA is appropriate and consistent with the purpose of the MCRA in managing core load fluctuations. Therefore, Terasen Gas is requesting approval from the Commission for the above noted changes in the pricing methodology and for the methodology of accounting for any volume and cost variances within the MCRA account.

Given the volatility in the natural gas marketplace in recent years, Terasen Gas believes it prudent and appropriate to continue to hedge the pricing associated with company use gas through Sumas fixed price swaps to provide protection against possible unfavourable movements in natural gas prices in the future. At the time of this application, Terasen Gas has applied for Commission approval to implement hedging of the forecast company use gas and anticipates receiving this approval in the near future. Therefore, until such time as the hedge is implemented, the company use gas cost forecasts presented within this application are reflective of current forward market prices and applicable taxes.

Based on this discussion, Terasen Gas believes that the company use gas unit costs and volumes as reflected above are prudent and appropriate for the period covered by this Application. As such, Terasen Gas is seeking approval for company use gas costs within the relevant O&M sections of this Application, which will be updated in the future based on the executed hedge prices if approval for hedging is granted.

(2) CORE MARKET ADMINISTRATION EXPENSE

(a) Background and Cost Drivers

Core Market Administration Expense ("CMAE") costs are a direct result of the activities performed within the Gas Supply department to serve core market customers and are treated as a flow-through cost to core market customers as part of gas costs. Providing safe, reliable, and cost effective gas supply resources which are required to meet core customers' load demands is at the center of the CMAE activities.

Over time, the scope of these activities has evolved to include several different entities and gas cost accounts. As a result of the 2004 amalgamation of TGI and TGVI operations, a single Gas Supply department was formed to supply all utility operations, including TGI, TGVI, TGW, and Terasen Gas (Squamish) Inc. (since amalgamated into TGI), with natural gas and propane supply management functions. The 2004 amalgamation of the gas supply function benefited customers through harmonization of the gas supply processes.

With the introduction of commodity unbundling in 2004, the TGI portfolio was split from utilizing a single gas cost deferral account, namely the GCRA, into utilizing two gas cost deferral accounts, the MCRA and the CCRA. While the CCRA account volume refers to the amount of annualized baseload supply required to serve core customers choosing to remain on the Terasen Gas standard rate offerings based on normal loads, the MCRA account includes the resources required to meet core customers' loads that arise from the seasonality inherent in winter and summer demand periods. These resources include seasonal gas purchases and peaking supply arrangements, transportation service on various regional pipelines and storage resources. Core Market Administration Expense for Terasen Gas is allocated between the CCRA and MCRA accounts based on the activities performed by employees in the Gas Supply department, with 30 per cent of CMAE allocated to the CCRA account and 70 per cent allocated to the MCRA account.

For the purposes of this Application, CMAE costs are presented on a consolidated basis, including the amounts for TGI, TGVI and TGW. The CMAE forecast costs will continue to be allocated to TGI, TGVI and TGW based on the current allocation method using customer count. For 2010 and 2011 this equates to 89 per cent for TGI, 10 per cent to TGVI and 1 per cent for TGW, which is the same allocation prior to 2010. The historical consolidated CMAE annual expenditures are shown below (with the projection for 2009).

Table C-5-2: CMAE Historical and Projected Costs ($ millions)

	2004	2005	2006	2007	2008	2009
Total CMAE	$2.04	$2.17	$2.19	$2.22	$2.41	$2.49

The key functions performed by the Gas Supply department in providing reliable, cost effective gas and propane resources for core customers of TGI, TGVI and TGW are as follows:

- Develop and implement the Annual Contracting Plans;

- Optimize the portfolio on a daily basis and mitigate any available "excess" resources to reduce costs for customers;
- Manage the Midstream and Commodity portfolios as per the Essential Services Model implemented as part of the Commodity unbundling program;
- Develop and implement the Price Risk Management Plans; and
- Provide Energy Management Services to minimize costs for customers through revenue generation.

(b) Annual Contracting Plans ("ACP")

The Annual Contracting Plans outline the portfolios required to meet the needs of core customers through contracting for an optimized and diversified mix of commodity, storage and transportation resources. They detail a one-year plan for procurement activities and also address longer term issues to provide an indication of anticipated longer term contracting or marketplace changes. The Annual Contracting Plans and the resulting contracts are filed with the Commission for approval each year. The primary objectives of the ACP include the following:

1. To contract for cost effective supply resources which ensure safe and reliable natural gas or propane deliveries to meet core customer design peak day while mitigating against potential upstream and downstream supply disruptions.
2. To develop a portfolio resource mix which incorporates price diversity and provides contracting flexibility for both short-term and longer-term planning.

An important part of developing this optimal portfolio is the evaluation of resources available to meet both normal and peak day core load requirements. This includes support activities such as portfolio modeling and resource assessment, regional supply and demand analysis, discussions and meetings with pipeline and storage operators, maintaining strong relationships with gas producers and marketers, negotiation and administration of commodity, pipeline and storage contracts, and staying on top of new regional infrastructure developments and seeking opportunities for contracting resources related to cost effective pipeline or storage capacity expansions or additions.

This activity has been important in the past and will continue to be important in the future as significant infrastructure developments are occurring in the Pacific Northwest region which will have major impacts on how the utility sources secure supply over the longer term. In particular, pipeline developments on both Spectra and Nova systems occurring in northern British Columbia due to the vast potential of natural gas production in the Horn River and Montney shale gas plays could affect Terasen Gas' ability to source Station #2 gas in the long term. As part of this Application, Terasen Gas will be seeking approval for costs for consultant studies or research incurred by Gas Supply related to evaluating resource options for core customers. This is in the interests of providing reliable and cost effective gas supply for customers, given the changing natural gas market within the Pacific Northwest and, in particular, developments in northern British Columbia regarding new production and infrastructure.

With regard to securing reliable and cost effective resources, Terasen Gas is proactive in regional resource developments and influencing the cost of available resources for the benefit of customers. This involves attending industry forums and conferences, being an active member of associations where Terasen Gas can promote its customers' interests, such as through the NWGA and WEI and participating in the regulatory proceedings of regional pipeline companies in which Terasen Gas has an interest. By participating in these regulatory proceedings and hearings with other active pipeline shippers that serve downstream markets, Terasen Gas has been able to achieve significant cost savings and provide more effective use of resources for core customers. Examples of successful regulatory outcomes that have improved the effectiveness of resources include authorized overrun service and late night nominations on the Spectra Energy pipeline system. Examples of cost savings include term differentiated rates on the Spectra Energy pipeline system (where shippers receive discounted rates for contracting for longer term service) and the extension of liquids extraction revenues for export shippers on the Nova Gas pipeline system, which provide a combined savings of over $4 million per year for core customers. As part of this Application, Terasen Gas will be seeking increases in legal and consulting costs related to participating in pipeline regulatory filings and proceedings in the interests of reducing costs for core customers.

The Annual Contracting Plan for Terasen Gas also involves consideration of marketer-provided volumes per the commodity unbundling program, ensuring that the appropriate amount of commodity is purchased on behalf of core customers choosing to stay with Terasen Gas as their commodity provider. The benefit to customers of these activities comes from the development of a cost effective diversified portfolio of resources which provides reliable energy supply during both normal and peak load periods.

In the future, the gas supply portfolio may also include natural gas sourced downstream of the typical resource mix procured by Gas Supply. With increasing government mandates and public desire for conservation and "green" energy solutions, new natural gas sources, such as biogas or other "green" initiatives, will likely become a growing part of the Terasen Gas resource mix in the future. Gas Supply's role may include contract management, supply management (incorporating new supply sources into the Annual Contracting Plan) and invoice verification and payments. It is expected that the cost of gas related to these initiatives would flow through to customers via the Midstream account. While Terasen

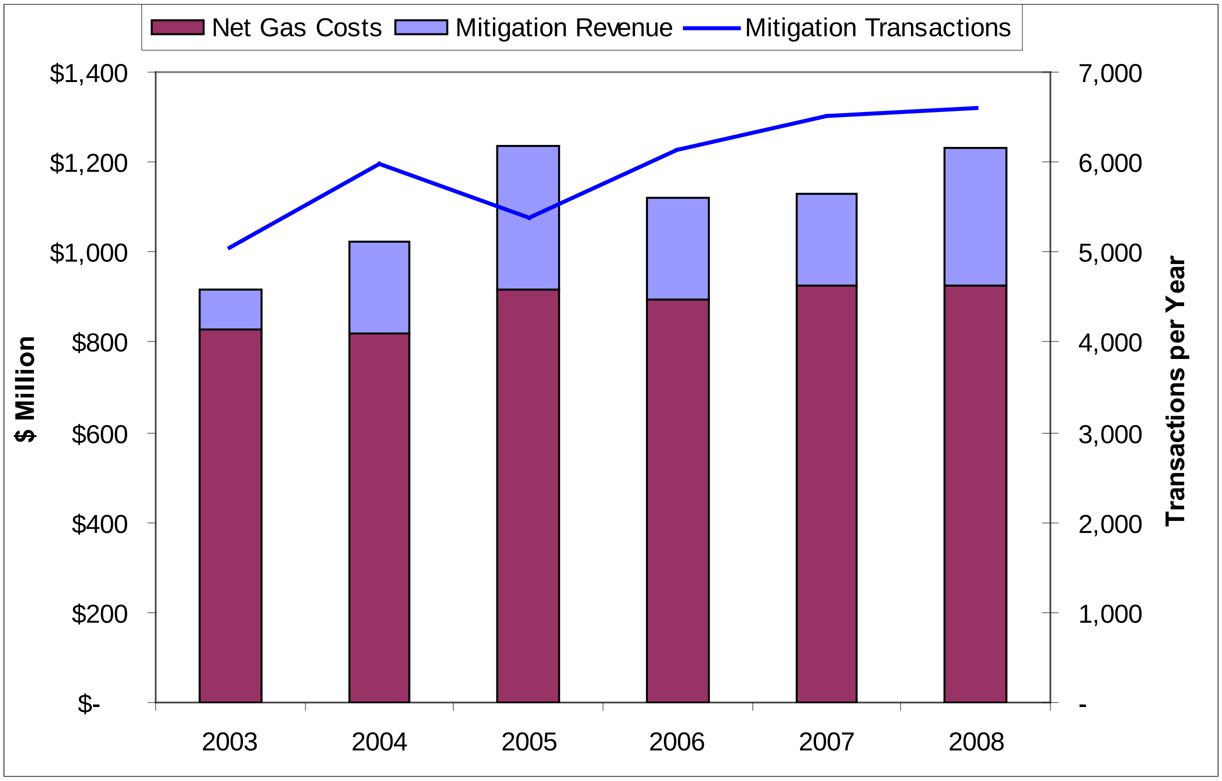
Gas anticipates these new sources of supply will be significant in the longer term and important for the company to continue customer growth, the costs for “green” energy management are not expected to be material in 2010 and 2011 and will be absorbed into the Gas Supply activities through synergies with existing processes.

(c) Portfolio Optimization and Mitigation Activity

The implementation of the Annual Contracting Plans involves utilizing the portfolio resources in the most optimal way to the meet daily load requirements. Consideration is given to daily load changes, time of year, market prices, pipeline constraints and resource type and duration when optimizing resources on a daily basis. Experienced employees and good communication within the Gas Supply and Transmission department have ensured commodity supply reliability through 100 per cent delivery to firm customers in the past.

During periods when the resources contracted to meet peak day requirements according to the Annual Contracting Plan exceed actual customer demand, the Company resells, or mitigates, the “excess” resources. In this way, mitigation activities improve the cost effectiveness of the ACP resources and in turn, help reduce gas costs. This activity involves substantial and increasing effort over time, includes thousands of transactions each year and results in significant savings for core customers which are reflected in the Midstream component of the cost of gas. The following chart illustrates the activity levels which translate into substantial cost reductions, averaging about $225 million per year (or 25 per cent of net gas costs average of $886 million per year) over the past six years.

Figure C-5-3: Gas Costs and Revenue and Mitigation Activity



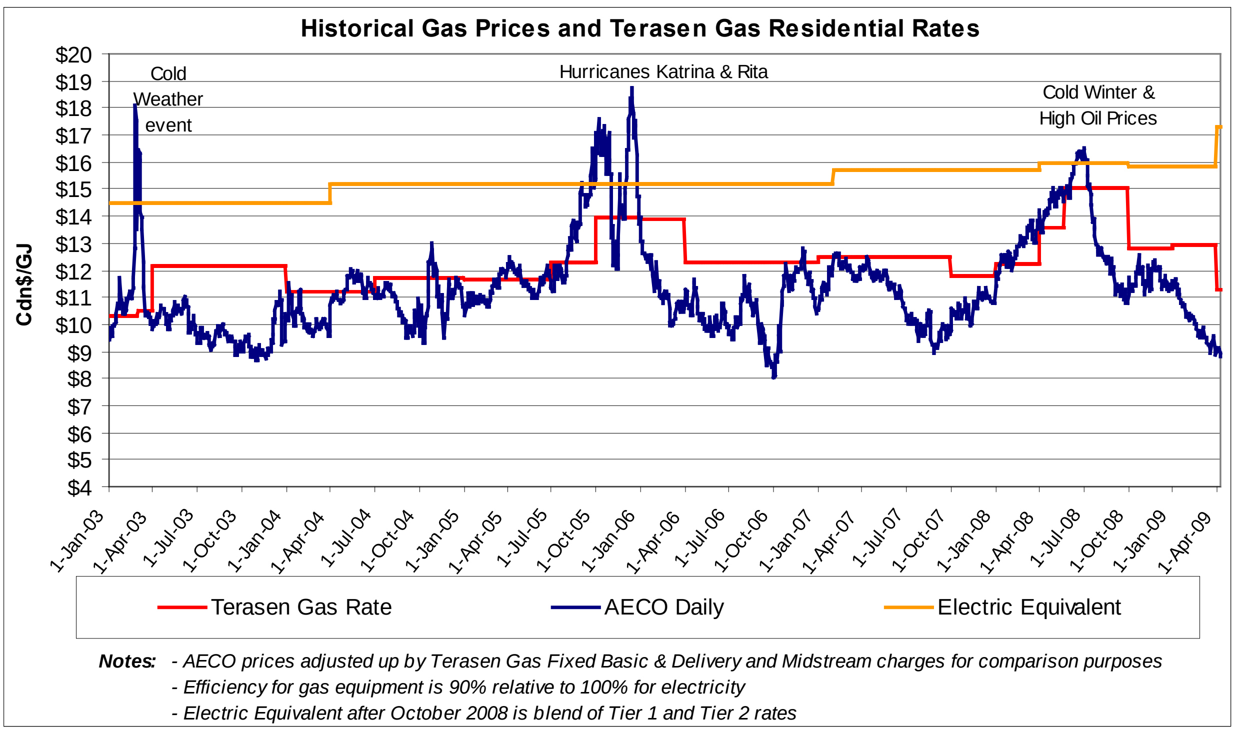
(d) Essential Services Model

With the introduction of commodity unbundling for commercial customers in 2004 (and residential customers in 2007), the CCRA deferral account was split into the CCRA and MCRA deferral accounts. At this time the Essential Services Model was established wherein Terasen Gas provides the Midstream resources required to ensure reliable and cost effective delivery of the gas commodity, whether sourced by Terasen Gas or marketers, to customers. The main functions performed by the Gas Supply department that relate to commodity unbundling include marketer invoicing, communication of volume requirements to marketers, monitoring marketer gas nominations, assessing any backstopping charges and monitoring and setting CCRA fuel rates. The Gas Supply department maintains strong communication with the Marketing department, which is responsible for the development and administration of program business rules, reporting and information systems. The Gas Supply and Marketing departments have effectively and responsibly managed the commodity unbundling program since its inception and will continue to do so in the future with Gas Supply ensuring marketer and TGI gas flows to customers even during times of peak system loads or third party pipeline constraints or plant disruptions. Ultimately, this provides customers with a choice of commodity provider through a program that is managed efficiently and at minimal cost to all customers.

(e) Price Risk Management

The Gas Supply department also develops and implements the Price Risk Management Plans for TGI, TGVI and TGW with the primary objective of reducing market price volatility and resultant rates for customers. The plans also improve the probability of remaining competitive with electricity rates over the longer term in order to attract customer growth and ensure optimum resource portfolios and overall cost effectiveness for all customers. The Price Risk Management Plans are designed within the context of the highly volatile natural gas and propane markets and include consideration of both high and low market pricing scenarios in the interest of smoothing volatility and reducing the likelihood of rate shock for customers. The following graph illustrates how the Terasen Gas residential rate, which includes the use of hedging and storage as elements of the Price Risk Management Plan, protects customers from the majority of the market price volatility during recent years.

Figure C-5-4: Terasen Gas Residential Rate Compared to Market Prices



(f) Energy Management Services

The Gas Supply department provides energy management services ("EMS") for other natural gas and propane utilities. Currently natural gas related services are provided to Pacific Northern Gas ("PNG") however in the past EMS clients have included Calpine Corporation and Methanex Corporation. Terasen Gas produces and implements the Annual Contracting Plan, develops the Price Risk Management strategy and executes hedges, optimizes the portfolio and manages daily load swings on behalf of PNG. The functions performed and the relevant issues for PNG are very similar to those outlined for Terasen Gas, enabling synergies to occur. Furthermore, the annual PNG revenue of approximately $170 thousand generated through EMS work flows directly into CMAE thereby benefiting core customers directly. In addition, EMS also provides management of propane supply for Terasen Energy Services Inc. ("TES") customers including Furry Creek and Sun Peaks on a cost reimbursable basis.

Energy management services also manages contracts related to third party shippers on the Terasen Gas Southern Crossing Pipeline system, which currently includes Northwest Natural Gas Company ("NWN"), while Midstream operations manages the nominations and scheduling of gas on SCP. This service provides value to third party shippers looking for supply diversity at a reasonable cost and also provides Terasen Gas core customers with a cost effective resource, yielding supply diversity and security in the winter and mitigation revenue opportunities in the summer.

(g) Support Activities

Support activities for the key functions performed by the Gas Supply department for core customers, include, but are not limited to, the following:

- negotiation of physical supply contracts;
- negotiation of financial derivatives contracts;
- administration of pipeline, storage and commodity contracts;
- regulatory and financial reporting;
- budgeting and cost accounting functions;
- counterparty credit management; and
- back-office compliance review.

Terasen plays a significant role on behalf of Gas Supply in the area of counterparty credit review and management, providing services that support physical purchase and sale activity as well as the price risk management strategy. These credit risk management support services provided by Terasen include counterparty credit reviews, determination of appropriate amount and type of collateral, negotiation of credit support documentation, negotiation of financial contracts and development of policies and procedures related to physical and financial transactions.

Credit review and management of both physical and financial counterparties has been increasingly important in recent years and in particular during the past year given the severe global financial and credit crisis, which has been highlighted by the failure of a number of global financial institutions. Credit exposure is carefully managed given term gas contracting, mitigation activity and surplus sales, high commodity prices and associated credit risk. Implementation of financial and physical transactions necessary to optimize gas supply management for core customers creates significant credit exposure and so Terasen Gas retains a strong internal control environment regarding credit and price risk management processes. The Internal Audit department reviews and confirms the Terasen Gas policies and processes to ensure compliance and continuous improvement. Terasen Gas has a conservative and well-defined credit policy that is actively managed and has avoided non-recoveries in the past while markets continue to experience high volatility.

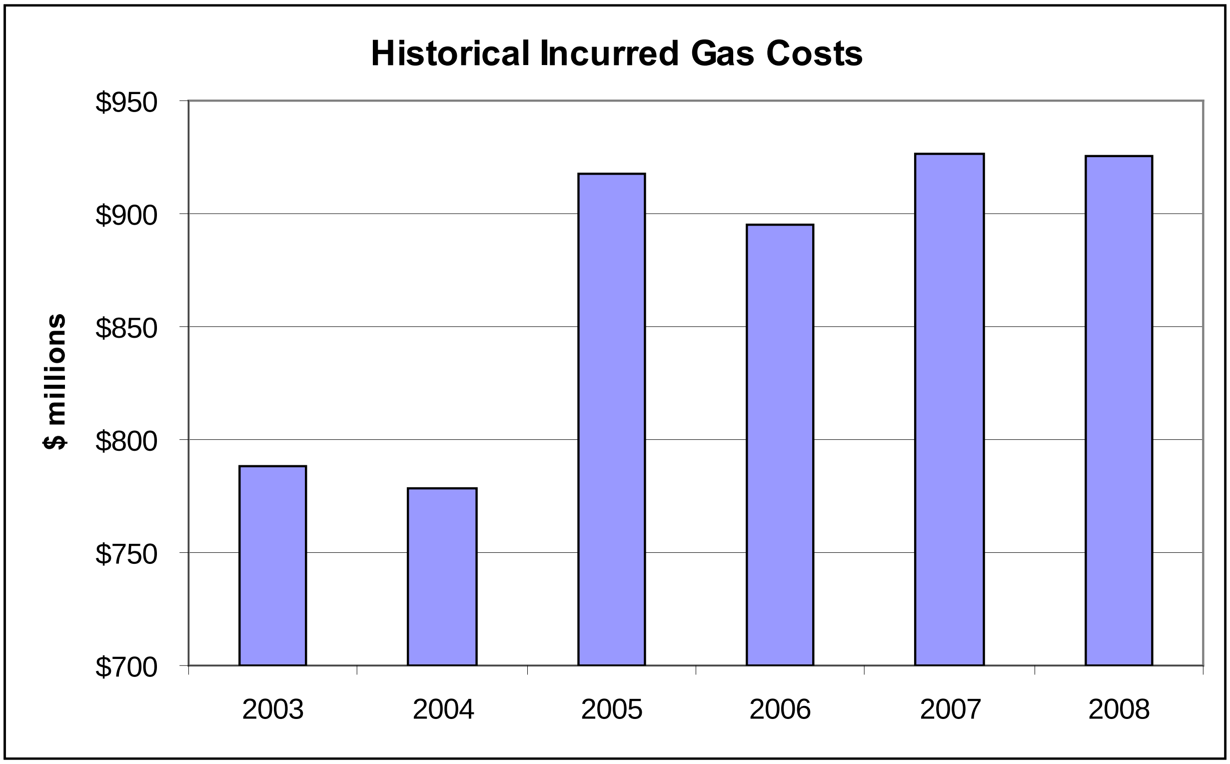
Terasen Gas also has numerous policies, procedures and controls in place as part of its mitigation strategies. These policies cover areas such as physical gas and derivative financial instruments trading and approval procedures and signing authority levels to define trading limits and terms and ensure that trading practices remain compliant to the controls. These policies and procedures are reviewed and updated regularly and employees are required to acknowledge the appropriate policies by signature to denote understanding.

Terasen Gas also performs a thorough credit review for each counterparty prior to signing a contract and requires a parental guarantee, letter of credit, security deposit or prepayment before trading can occur. Exceptions with regard to collateral are made only for companies with sound financial performance and any unsecured credit limits are established by the Terasen Treasury department.

Furthermore, the credit management group subscribes to a number of news alert web sites which provide notification of any significant news releases that highlight events that may materially affect a company's creditworthiness. This information allows for prompt action that may lead to a counterparty's credit rating downgrade or prevent impending payment defaults. All relevant information is openly communicated within a timely manner across the Gas Supply department.

The following figure demonstrates the changes in recent years in the energy markets as gas prices and costs have increased significantly. The increased number of transactions and higher prices results in both increased workloads and necessity for solid credit risk management in the Gas Supply department.

Figure C-5-5: Historical Incurred Gas Costs



All of these activities performed by the Gas Supply department, and funded through CMAE, have been performed prudently and cost effectively, with no significant changes in department headcount or costs over the past few years. Over time, the Gas Supply department has evolved into commodity, midstream, compliance and credit, back-office support and resource management groups. This latter group includes energy management services, third party storage and transportation contracting and market development, which focuses on marketplace infrastructure developments in the interests of securing resources and reducing costs for core customers.

As mentioned, the activities within the Gas Supply department have included the incremental work resulting from the acquisition of TGVI and commodity unbundling for both commercial and residential customers. The Gas Supply department has been able to manage this increased scope and activity over the past five years largely through process improvements, synergies and effective use of technology.

The Gas Supply Nucleus product is the IT system used to capture the costs and volumes related to the commodity, storage and transportation resources, transactions related to mitigation activities and maintains price groups per marketer offerings under the commodity unbundling program. This system is then able to generate reporting required for nominations and scheduling of gas, gas costs for budgeting purposes and regulatory filings and invoices. In 2010, after the upgrade from the Nucleus to the Entegrate platform expected to be completed in 2009, this product will also provide Gas Supply with enhanced risk management capability, including automated financial and physical mark-to-market functionality and other related reporting. This product serves to centralize data and information for the Gas Supply department and will continue to meet the growing needs of the group in the future.

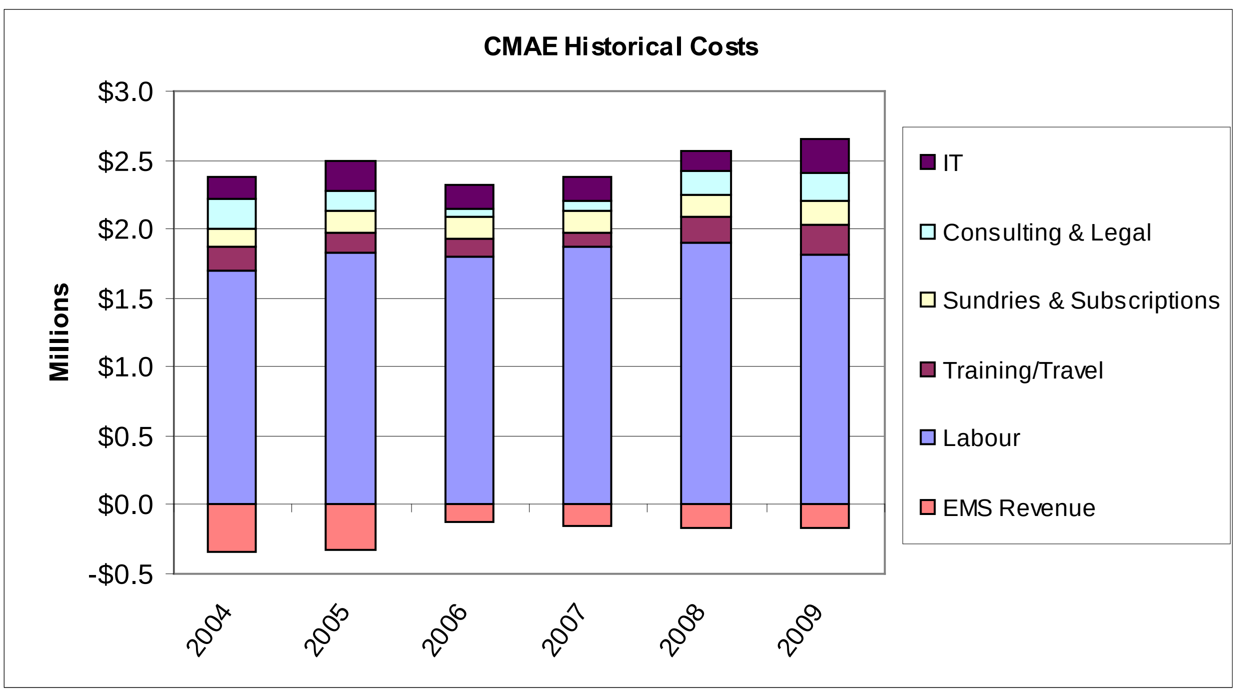
The following table shows the historical and projected 2009 headcount (expressed as full time equivalents).

Table C-5-3: CMAE Historical and Projected Full Time Equivalents

	2004	2005	2006	2007	2008	2009
Full Time Equivalents	15.8	16.3	16.3	16.6	16.6	16.7

The following figure shows the historical and 2009 projected costs by category related to CMAE since 2004, followed by an explanation of the various cost categories.

Figure C-5-6: CMAE Historical and Projected Costs



As presented in Figure C-5-6, costs related to labour represent the largest component of CMAE costs. IT costs primarily relate to annual license fees and database and server support related to the Nucleus product, which enables Gas Supply to operate efficiently and generate necessary reporting and invoicing. Consulting and legal costs (provided by external parties) arise primarily from contracts review, participation in pipeline companies' regulatory applications and proceedings and external regional resource studies, which allow Terasen Gas to help reduce portfolio costs and provide reliable and cost effective resources over the long run for core customers. Sundries and subscriptions costs are primarily related to natural gas pricing information and market research subscriptions, including credit monitoring services, as well as memberships in natural gas associations, such as the Northwest Gas Association. Training and travel expense covers costs for Gas Supply department employees traveling to and attending industry courses and conferences and developmental or management courses. This enables employees to stay on top of the latest industry developments and develop their management and communication skills and industry knowledge. Lastly, EMS revenue is shown as a revenue stream and relates to providing energy services to third parties, such as PNG, and serves to reduce CMAE costs for core customers.

As part of this Application, Terasen Gas is seeking slight increases in the base CMAE costs for 2010 and 2011 in order to continue providing reliable and cost effective service for core customers. Furthermore, Terasen Gas is seeking approval to allocate costs related to Gas Supply functions for core customers that are currently funded by utility O&M appropriately into CMAE. The following section will outline these requests for approval.

(h) Request for Commission Approval

(i) Increase in Base CMAE

CMAE increases since 2004 have averaged just over 4 per cent per year. The increases have primarily been related to inflation, IT cost increases (due to support services and license cost increases) and the reduction in EMS customers after 2005. Terasen Gas is requesting approval for base CMAE increases for 2010 and 2011 primarily related to labour inflation and benefits cost increases plus an additional $102 thousand in 2010 and $123 thousand in 2011 (over 2009 forecast amounts) for additional legal and consulting expenses. This is required to represent customers' interests in third party pipeline regulatory applications as well as for external regional resource studies or consulting work related to evaluating resource options for core customers, in the interests of providing reliable and cost effective gas supply. The following section details why Terasen Gas believes these increases are appropriate.

Significant infrastructure changes are taking place in the Pacific Northwest natural gas marketplace. Pipeline expansions are occurring to keep pace with demand requirements and incremental sources of supply. New pipeline routes have been proposed by various companies to move excess gas out of the Rockies supply basin, potentially affecting the amount of contracting by other PNW utilities on the Westcoast Energy Inc. ("Westcoast") system. In Canada, TransCanada Pipelines Limited ("TCPL") has received National Energy Board approval for federal regulation of its Alberta system, enabling Nova Gas Transmission Limited ("NGTL") to pursue building pipelines to take gas from the British Columbia Horn River and Montney shale gas plays into Alberta to feed the oil sands demand and other eastern markets. At the same time, Westcoast is proposing expansions to its northern pipeline system to move new shale gas to markets south and east to Alberta on its existing network. These developments could result in significant changes in tolls on the pipelines on which Terasen Gas contracts for capacity and impact Terasen Gas' planning to secure cost effective supply for customers. Using NGTL as an example, for every $0.01/GJ of toll reduction that Terasen Gas, along with other export shippers, is able to achieve, the savings to core customers via the cost of gas would equal over $500 thousand per year. Therefore, Terasen Gas expects to be active in the future applications and hearings for NGTL and Westcoast, and potentially also Northwest Pipeline Corporation ("NWP") on which Terasen Gas contracts for service. These future applications would include any expansion proposals, relevant rate design and revenue requirement applications and settlement negotiations.

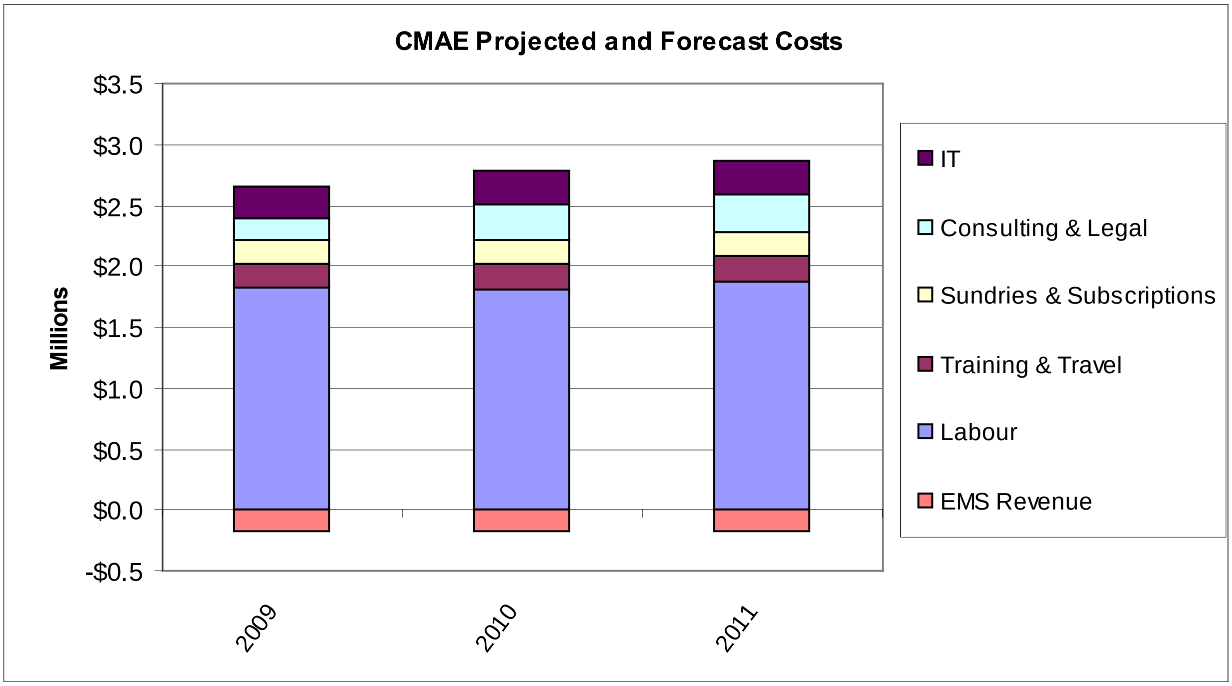
Furthermore, Terasen Gas is active in working with other regional utilities and pipeline companies related to regional resource planning through organizations such as the Northwest Gas Association (NWGA). In light of these significant gas supply and infrastructure developments, on-going evaluation and development of the threats and opportunities to respond to these challenges is expected to increase. For example, Terasen Gas is currently working with Spectra Energy to evaluate the feasibility of providing a joint transportation service from northeast British Columbia to the Kingsgate market hub using the transmission systems of both companies. The benefits to customers would be related to the more efficient use of existing infrastructure as well as supporting the development of new gas production. Terasen Gas believes participation in upstream pipeline applications and regional resource planning is important to ensure that TGI defends its customers' interests and makes every attempt to keep upstream pipeline costs at a reasonable level.

The 2009 projected and forecast base CMAE costs for 2010 and 2011 are presented below. Terasen Gas does not anticipate any incremental headcount for 2010 or 2011 (from 2009 levels).

Table C-5-4: Base CMAE Projected and Forecast Costs ($ millions)

	2009	2010	2011
Base CMAE	$2.49	$2.61	$2.69

Figure C-5-7: Base CMAE Projected and Forecast Costs



Terasen Gas believes that the forecast base CMAE increases for 2010 and 2011 are appropriate and required to continue its proven prudent management of Gas Supply portfolio costs and to ensure security of supply for core customers. Reallocations of O&M costs to CMAE, over and above the base CMAE increases requested, will now be discussed.

(ii) Transfers from O&M to CMAE

Since 2004, the Gas Supply department has first taken on work for TGVI and TGW and then, as a result of commodity unbundling, separated TGI activities into Midstream and Commodity services. Terasen Gas believes that the time has come to realign costs between TGI O&M and CMAE to ensure the appropriate allocation of costs to core customers of Gas Supply services. Therefore, Terasen Gas is requesting approval for CMAE increases of $1.40 million in 2010 and $1.45 million in 2011 (over 2009 projected amounts), offset by an equal reduction in O&M expenditure. This request is therefore a reallocation of costs to direct them to the appropriate customer groups and does not represent an increase in the Company's requirements for CMAE and O&M.

The following section details the items Terasen Gas is proposing to reallocate from O&M to CMAE which consist of direct and indirect costs.

The first of these direct costs relates to the Gas Accounting group, currently funded by the Finance and Regulatory Affairs department O&M. It consists of one manager and three employees who perform regulatory reporting, rate review and setting processes, prepare gas-related tax filings, and support the various Gas Supply processes and reporting on behalf of Terasen Gas Midstream and Commodity, TGVI, and TGW. These activities are entirely due to Gas Supply services and should be moved to CMAE so that the costs are allocated appropriately to core customers. The costs for this group primarily consist of labour costs and are forecast to be $433 thousand in 2010 and $456 thousand in 2011. The increases from the 2009 forecast of $400 thousand are due to inflation and increases in benefits costs.

The second of these direct costs includes the Company incentive payments (exclusive of the Gas Supply Mitigation Incentive Program or "GSMIP" payments) for staff in the Gas Supply department who directly contribute to services for core customers. Historically this incentive pay has been funded through the department's O&M but should appropriately be included in the CMAE along with the corresponding employee salaries. The forecasted amounts for 2010 and 2011 are $243 thousand and $251 thousand, respectively, increasing from the 2009 forecast amount of $232 thousand by inflation and related salary increases.

Indirect costs include those services performed by other parts of the organization that enable the Gas Supply department to function efficiently and effectively on behalf of core customers. In this case, Terasen Gas believes that a shared services methodology is appropriate wherein fees would be charged to CMAE to offset O&M costs in other departments within Terasen Gas and Terasen. This is consistent with the shared services fee between Terasen Gas and Terasen Energy Services to ensure that costs are appropriately allocated between the two entities and reduces the need for multiple cross-charging of costs between various inter-company departments. The shared services fees for CMAE would include the costs for services performed for Gas Supply related to the following:

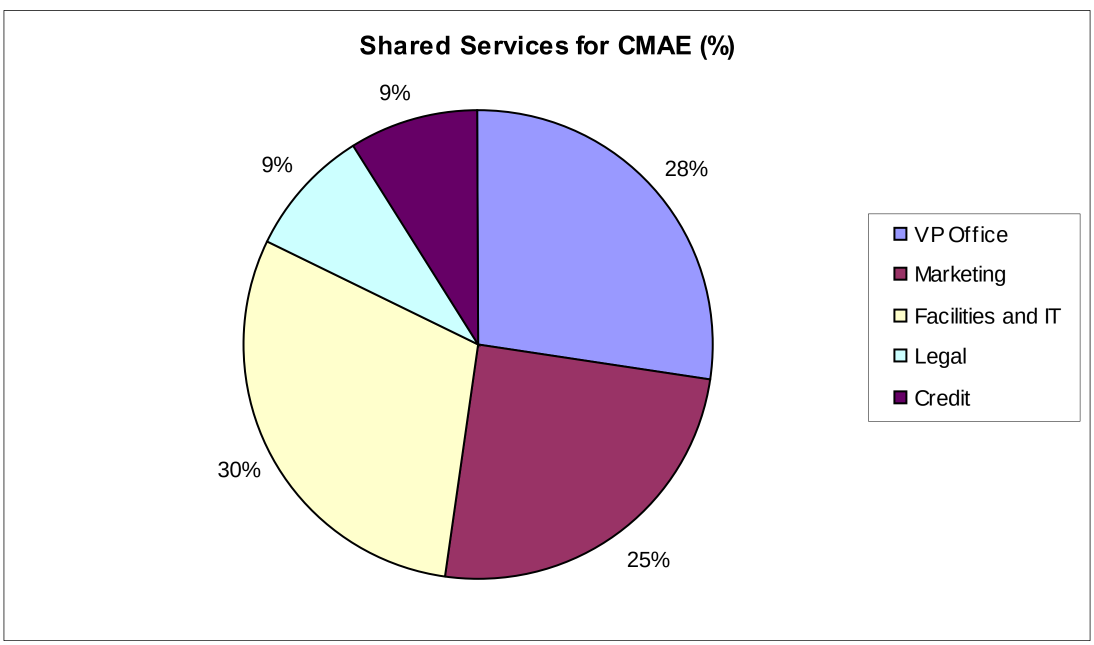
- Vice-President of Gas Supply and Transmission office (management oversight);
- Marketing (core customer load forecasting);
- IT (support services);
- Facilities (office space and materials);

- Legal counsel (contracts review); and
- Credit risk management (contract negotiation and counterparty credit analysis).

The last item of credit risk management is a function provided by Terasen on behalf of the Gas Supply department and the shared services fee is in response to the requirement for credit analysis regarding the assessment and monitoring of physical and financial counterparties and assistance in negotiating both physical commodity and commodity derivative contracts for the Gas Supply department. As a result of the financial and credit crisis that has occurred over the past year, many companies have had their credit ratings downgraded and in certain instances, have gone bankrupt. As such, credit evaluation and analysis work has increased for Terasen Gas as it continues to ensure physical and financial counterparties, necessary to its business, are sound. As Terasen Gas expects the global financial and economic turmoil to continue for the foreseeable future, increased credit risk management activity is prudent and required. The credit risk management costs arise from a role that would be shared by the Gas Supply department and Terasen with 50 per cent of the costs being allocated to CMAE. Terasen Gas believes the incremental costs of $65 thousand in 2010 and $67 thousand in 2011 related to this credit risk management is appropriate and prudent in ensuring core customers interests in cost effective and secure supply are protected.

Figure C-5-8 shows the percentage allocations of the proposed shared services for CMAE.

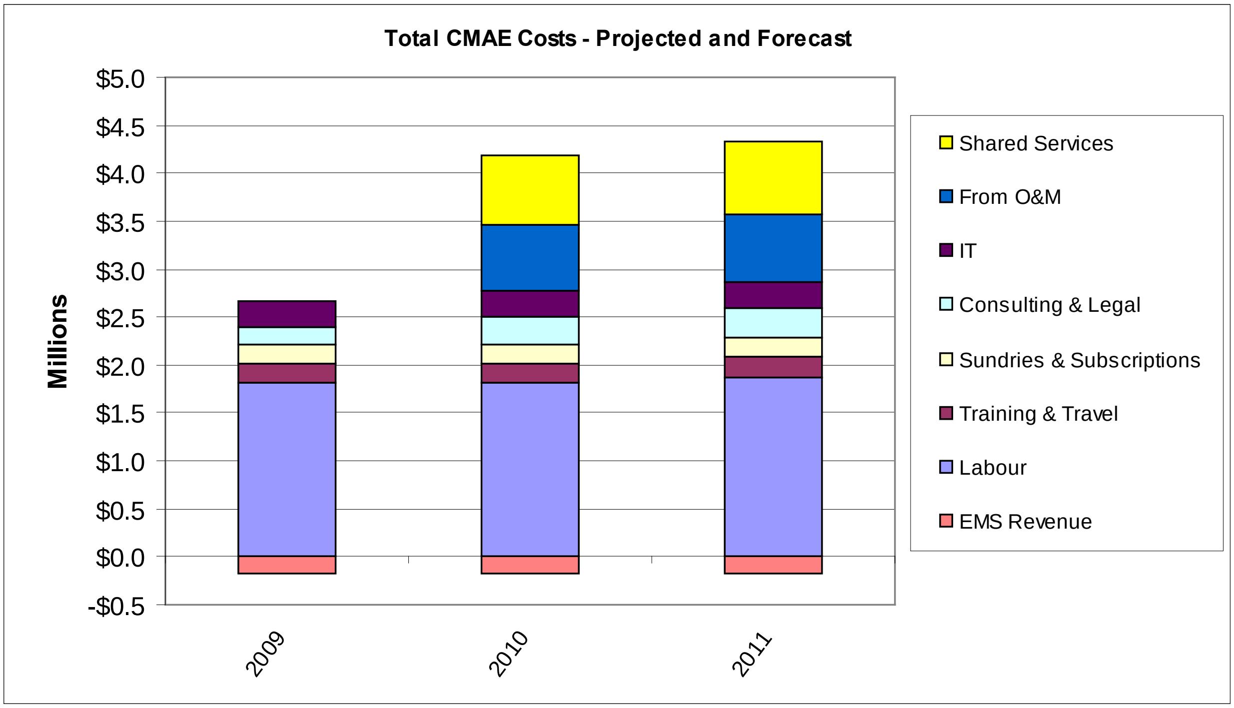
Figure C-5-8: Forecast CMAE Shared Services for 2010 and 2011



The proposed amount of the shared services costs for 2010 and 2011 to be included in CMAE are $725 thousand and $745 thousand, respectively.

The increases in base CMAE costs plus the reallocation of costs from O&M to CMAE produce the total forecast CMAE costs for 2010 and 2011 which are reflected in the following figure.

Figure C-5-9: Total CMAE Projected and Forecast Costs



As discussed above, the proposed incremental CMAE costs are due to a transfer of direct and indirect costs from O&M (indicated by 'From O&M' and 'Shared Services' in the previous figure) and so are offset by a reduction in O&M expenditures for 2010 and 2011. Overall, the requested costs to manage the gas supply functions, including CMAE and O&M, have not increased from 2009 (other than cost increases related to inflation and benefits).

Terasen requests approval of its forecast 2010 and 2011 CMAE consolidated costs, which will be allocated appropriately to TGI (Midstream and Commodity), TGVI and TGW using the aforementioned allocation methodology and which are presented in the following table.

Table C-5-5: Total CMAE Forecast Costs ($ millions)

	2010	2011
Base CMAE	$2.61	$2.69
O&M Reallocations	$1.40	$1.45
Total CMAE	$4.01	$4.15

Based on an allocation of 89 per cent to TGI (with the remaining 10 per cent to TGVI and 1 per cent to TGW), TGI's share of the forecast consolidated costs is $3.57 million for 2010 and $3.69 million for 2011. Terasen Gas will continue to monitor the percentages used as part of CMAE allocations and will inform the Commission if these percentages no longer are representative of the activities done for TGI (Midstream and Commodity), TGVI and TGW.

In summary, the Gas Supply department is responsible for providing reliable cost-effective supply for natural gas and propane customers and transportation service for industrial and commercial customers for TGI, TGVI and TGW. The Gas Supply department has provided these services in a prudent and cost effective manner in the past. Terasen Gas is seeking slight increases in O&M and base CMAE to continue providing this high level of service for customers in 2010 and 2011. Furthermore, Terasen Gas believes it is appropriate and fair to reallocate certain specific O&M costs related to activities which support gas supply services for core customers to CMAE. This ensures an appropriate allocation of CMAE costs to TGI (Midstream and Commodity), TGVI and TGW.

(3) GAS SUPPLY MITIGATION INCENTIVE PLAN

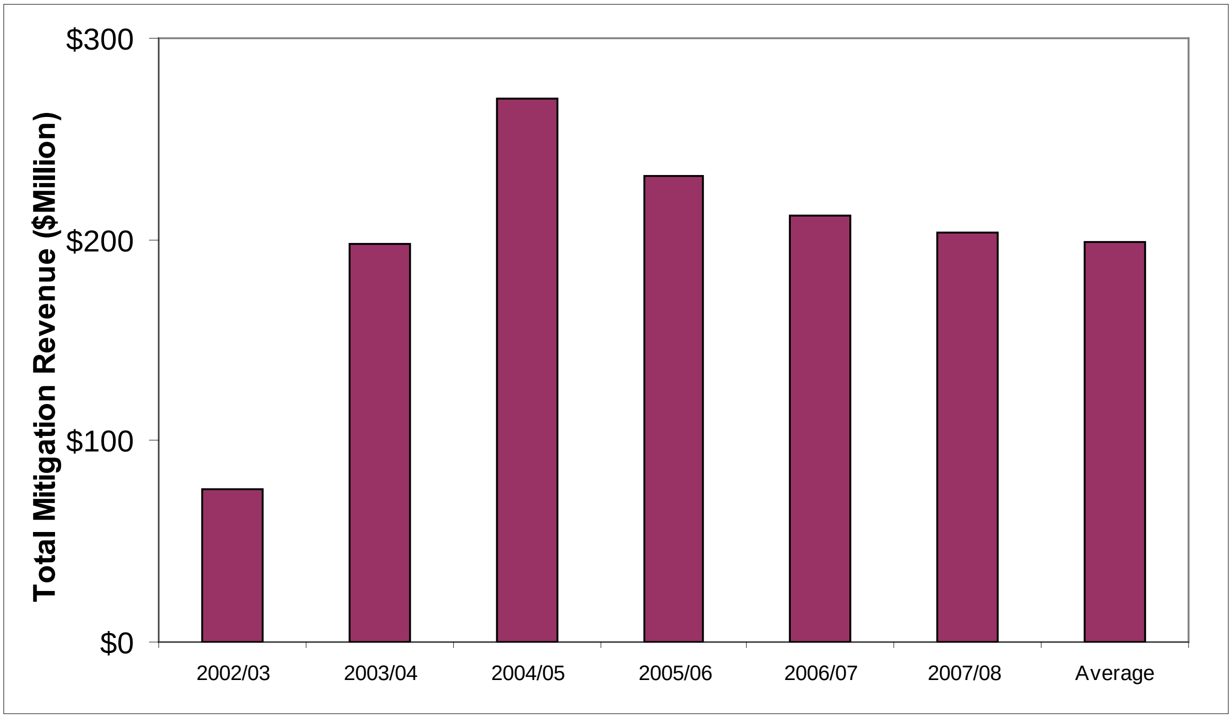
In order to align interests between core customers, Terasen Gas shareholders and employees, an incentive arrangement was established in 1996 to provide a sharing arrangement around this mitigation activity. The current mechanism, the Gas Supply Mitigation Incentive Plan ("GSMIP") has been in place since 2002/03 following a negotiated settlement and has been renewed each gas contract year following approval from the Commission. Over the years, customers have benefited greatly from the resources and expertise the Company committed to create value from the sale of 'excess' resources related to commodity re-sales, unused transportation and storage resources and other revenue generation (such as extracted liquids sales).

SQI's were established as part of the GSMIP mechanism to provide the Commission a means to monitor and evaluate the performance of the Gas Supply functions. These SQI's relate to resource contracting, price risk management, counterparty risk and credit management and commodity supply reliability.

Since 2002/03, Terasen Gas has met all the SQI performance targets while at the same time Terasen Gas has delivered exceptional customer value from mitigation.

Figure C-5-10 illustrates the total mitigation revenue including commodity re-sale revenue, storage, transportation and other margin, mitigation.

Figure C-5-10: Total Mitigation Revenue



Based on the preset formula to determine the eligible margin, core customers have received the majority of the benefits of this mitigation activity in terms of reduced resource costs, with a minor portion averaging just over $1 million per year being allocated to Terasen Gas shareholders and employees.

Terasen Gas is proposing a new three-year incentive mechanism for the period of November 1, 2009 to October 31, 2012 which reflects changes in the way Terasen Gas contracts for supply resources per the Annual Contracting Plan and also recent changes in market conditions, particularly around counterparty risk and credit. Terasen Gas has only provided this discussion for informational purposes in the RRA, as it intends to file with the Commission a separate application for the new three-year incentive mechanism in June 2009.

(4) SUMMARY

The cost of gas includes the energy (natural gas or propane) costs, the midstream related costs and the costs associated with providing gas supply services. Gas is contracted by the Gas Supply department to meet the objectives of safe, reliable and cost effective resources for core customers.

Terasen Gas manages these costs in a prudent manner, which is reflected in the CMAE, included in the cost of gas flowed through to customers via rates. Since 2003, there have been no significant changes in CMAE headcount or costs. Going forward, for 2010 and 2011, Terasen Gas is seeking slight increases in base CMAE primarily related to labour inflation and benefits cost increases plus additional funding for additional legal and consulting expenses. This is required to represent customers' interests in third party pipeline regulatory applications as well as for external regional resource studies or consulting work related to evaluating resource options for core customers, in the interests of continuing to provide reliable and cost effective gas supply.

Terasen Gas is also seeking to reallocate some O&M expenditures to CMAE in 2010 and 2011 (with offsetting reductions in O&M expenditures) to better reflect an appropriate allocation of costs to core customers. This includes direct costs related to the Gas Accounting group and incentive payments to employees within the Gas Supply department. It also includes indirect costs which include shared services provided by other departments that support the Gas Supply department's activities.

Terasen Gas believes these changes to CMAE are prudent and appropriate and necessary for the Gas Supply department to provide reliable supply for natural gas and propane customers and transportation service for industrial and commercial customers for TGI, TGVI and TGW in the future.

With respect to company use gas, Terasen Gas is requesting approval from the Commission for the change in pricing methodology and for the methodology of accounting for volume and cost variances within the MCRA account, as part of the cost of gas. Terasen Gas believes the change in pricing methodology is appropriate given the expiry of the 'netback' contracts and that Sumas pricing at the Huntingdon market hub is a reasonable and appropriate proxy and representative of where the gas is ultimately consumed. Terasen Gas believes accounting for volume variances, whereby actual company use gas volumes may differ from forecast primarily due to changes in weather, core load requirements and pipeline operating conditions, within the MCRA is appropriate because it is consistent with the purpose of the MCRA in managing core load fluctuations.

The forecast company use gas costs are recovered through O&M expenditures and more details regarding these costs are presented in the relevant O&M sections of this Application.

6. Operations and Maintenance Expenditures

a) Introduction

Terasen Gas' O&M expenditures required to operate the business and meet the needs of customers include Distribution and Transmission related costs to maintain and operate Terasen Gas' delivery system; business application software maintenance and IT support costs; Engineering and Operations Support costs; Customer Care and Marketing costs to service the needs of customers; and the costs of the Finance and Regulatory Affairs, and Human Resources and Operations Governance supporting functions.

O&M expenditures are affected by a number of different cost drivers. New cost pressures can come from a variety of influences, including increases in operating activities, inflation on internal labour, contracts and materials, and new business drivers. To ensure an optimal allocation of financial resources at Terasen Gas, O&M budgets are reviewed, updated and approved annually. Forecasted O&M expenditures by departments are developed on a trended and zero-based approach where appropriate. Departments review their existing O&M budgets and identify incremental funding requests with supporting justification provided. Budgeting using this comprehensive approach helps to ensure an appropriate allocation of resources amongst the various departments.

The 2010 and 2011 O&M incremental funding requests represent both cost pressures and savings which the Company believes are required to enable it to continue providing safe, reliable and cost efficient service to customers.

b) 2009 O&M as the Base

In determining the 2010 and 2011 O&M incremental funding requests, Terasen Gas used the most recent 2009 O&M projection as the starting point. Terasen Gas believes this starting point represents a reasonable level of base expenditures given it has been shaped by the benefits associated with performance based incentives. We have demonstrated this in Part III, Section B, Tab 1, where we compared the Company's O&M per customer to other gas utilities in Canada, and also to the 2003 Decision amount, both in dollars and on a per customer basis.

Comparing the O&M per Customer in real dollars from the 2003 Decision to the forecast for 2010 and 2011 demonstrates the culture of cost consciousness that Terasen Gas continues to display into the forecast period. This is especially true after adjusting for exogenous-type factors, i.e. factors beyond the control of the Company, that have been built into the 2010 and 2011 requests.

Table C-6-1: O&M per Customer is Lower in 2010 and 2011 than 2003

	Decision	Projection	Forecast	
	2003	2009	2010	2011
Total Gross Nominal O&M Expenses ($ millions)	$ 181.7	$ 195.1	$ 209.6	$ 219.1
Total Gross Real O&M Expenses ($ millions)	$ 204.7	$ 195.1	$ 205.7	$ 210.8
Average Number of Customers	770,368	833,798	839,949	845,633
Real O&M per Customer	**$ 266**	**$ 234**	**$ 245**	**$ 249**
Exogenous Factors built into 2010 and 2011 O&M:				
Government Policy Changes			(0.6)	(0.7)
Codes and Regulations			(5.3)	(7.4)
Accounting Changes			1.7	2.1
Change in items allocated to Core Market Admin Expense			1.4	1.5
Restated for Comparability:				
Total Gross Nominal O&M Expenses ($ millions)	$ 181.7	$ 195.1	$ 206.8	$ 214.6
Total Gross Real O&M Expenses ($ millions)	$ 204.7	$ 195.1	$ 202.9	$ 206.5
Real O&M per Customer	**$ 266**	**$ 234**	**$ 242**	**$ 244**

Another useful comparison in establishing 2009 as the appropriate base for forecasting 2010 and 2011 expenses, is to consider what the 2010 and 2011 O&M would have been under an extension of the PBR Agreement for two more years, and used the 2009 formula O&M as the base. Under this scenario (calculation shown in Table C-6-2 below), the formula O&M would have been calculated at $210.6 million in 2010 and $217.2 million in 2011, assuming no efficiency factor. This demonstrates that the nominal restated O&M expense forecasts for those years of $206.8 million and $214.6 million respectively are **less than** the amounts that would have been forecast under the extension of the PBR Agreement for two more years.

Table C-6-2: Calculation of Formula O&M for 2010 and 2011

(Amounts in $000s)	**2010**	**2011**
Prior Year Approved Gross O&M*	207,368	212,867
Customer Growth Factor	0.74%	0.68%
CPI	1.9%	2.0%
Formula O&M	212,867	218,593
Pension & Insurance Variance	(1,551)	(695.0)
Ft Nelson	(678)	(696.0)
Calculated Formula O&M	**210,638**	**217,202**

* Adjusted for actual 2008 and projected 2009 average customers

These comparisons demonstrate our intention to maintain the efficiencies gained during the PBR Period while meeting the changing needs of our stakeholders.

c) 2009 vs. 2010 and 2011

(1) OVERALL SUMMARY BY BUSINESS DRIVERS

Terasen Gas proposes the following 2010 and 2011 incremental O&M expenditures by business driver outlined in Table C-6-3 below. For consistency and clarity of discussion, the incremental O&M expenditures for 2010 and 2011 have been categorized into themes similar to that described earlier in Part III, Section A.

Table C-6-3: O&M Incremental Funding to Meet Our Customers Needs

Year	*Prior Year*	Labour Inflation and Benefits	Government Policy	Code and Regulations	Customer / Stakeholder Behaviours and Expectations	Demographics	Accounting Changes	Service Enhancements	Total Incremental	Total Forecast
2010	195,079	2,816	592	5,297	4,526	817	(3,141)	3,604	14,511	209,590
2011	209,590	5,344	113	2,059	599	216	(506)	1,734	9,559	219,149

The highlights of this request are:

- Labour inflation and benefits are for expected wage and benefit increases for our employees.
- Government Policy funding requests are for additional resources needed to respond to changes in government policy regarding energy efficiency and GHG reduction.
- Code and Regulations funding requirements are driven by Terasen Gas' need to comply with existing codes and anticipated new or changed codes.
- Driving the cost pressures in the category of Customer/Stakeholder Behaviours and Expectations are changes in energy use and impact on the environment, management of First Nations relationships and increasing expectations for customer service delivery.
- Demographic challenges regarding Terasen Gas' aging employee workforce require increased efforts to proactively recruit, train and develop, transition, and overall manage our workforce in the coming years.
- Accounting Changes and the need to comply with IFRS will affect the classification and timing of costs.

- Terasen Gas will need incremental funding to address service enhancements to maintain our standing as a respected and trusted operator that provides safe, reliable and cost effective utility service to customers.

Following is a discussion of each category of business driver and the factors and reasons influencing the incremental funding requests identified.

(2) LABOUR INFLATION AND BENEFITS

O&M labour and benefit increases in 2010 and 2011 are forecasted to be $2.8 million and $5.3 million respectively, including seniority related step increases for unionized staff.

Labour Inflation

As outlined in Appendix F-7: Forecast Assumptions, labour inflation in 2010 is forecasted at 3 per cent for all categories of employees: M&E, IBEW and COPE. The IBEW and COPE increases are based on a negotiated contract increase whereas the M&E increase is an estimate. In total, labour inflation accounts for approximately $2.3 million of the $2.8 million forecast increase in labour and benefits.

Labour inflation in 2011 is also forecasted at 3 per cent annually for all categories of employees, accounting for approximately a $2.3 million increase. The IBEW increase is based on a negotiated contract increase whereas the M&E and COPE increases are estimates.

Benefits

Employee benefits costs are reviewed annually for changes. Employee benefits include Workers' Compensation Board, Long Term Disability, Extended Health Benefits and Dental, Group Life, Medical Services Plan, Pension, Canada Pension Plan, Employment Insurance, Employee Savings Plans, Share Purchase Plans and Other Post Employment Benefits ("OPEB") for employees. For budgeting purposes, employee benefit costs are calculated and expressed as a percentage of total available employee labour dollars for determination of labour charge-out rates.

In 2010, benefits costs are forecast to increase, driven primarily by pension costs which are expected to increase significantly. In recent years, Terasen Gas' annual pension expense has been very low compared to historic amounts with the trend starting to reverse as investment returns decline. This trend, coupled with the investment losses incurred within the IBEW and COPE pension plans in 2008, is leading to a forecasted increase in pension expense in 2010 and 2011. TGI is projecting an increase in its pension expense of $2.4 million in 2010 and an additional $0.9 million in 2011 under Canadian GAAP based on available information as of December 31, 2008. The increases in pension are allocated between O&M and capital, based on the chargeable hours recorded against O&M and capital activities.

In 2010, pension and OPEB changes in O&M, net of accounting changes total to an increase of approximately $0.5 million. Pension and OPEB costs are apportioned into a current service component and a retiree component, with the retiree component remaining in O&M and a portion of the current service component eligible for capitalization by including these costs in labour rates that are directly charged to capital. The retiree portions of the pension expense and the OPEB costs that remain in O&M are expected to decrease in 2010 by $2.9 million with $1.7 million due to the accounting change discussed in Part III, Section C, Tab 11, Property, Plant and Equipment – Capitalization Policies on page 479, $0.8 million for reduced actuarial expense for OPEBs and $0.4 million for other adjustments.

In 2011, an increase in benefits costs of approximately $3 million, driven primarily by union employee savings plan and flex benefits changes will lead to an increase in O&M of approximately $2 million based on the estimated split between O&M and capital chargeable hours forecasted.

(3) GOVERNMENT POLICY

As demonstrated in Part III, Section A, Terasen Gas is being impacted by changes to the external environment, specifically, government policy relating to energy efficiency and GHG reduction. As such, customer, government and stakeholder expectations have changed. Some of Terasen Gas' customers including municipalities, health authorities and government housing, commercial and industrial customers are increasingly asking for more detailed reports on their usage of gas over past periods, ranging from one to five years, in order to manage their energy consumption and impact on the environment. In addition, Terasen Gas is required to manage the impact of GHG reduction legislation on its business. Like other environmentally responsible corporate citizens, Terasen Gas must continually review and evolve its environmental governance efforts in order to remain compliant with changing legislation, regulatory requirements, and government initiatives.

To meet these challenges and continue to provide the service demanded by our customers, we will require additional staffing resources, and their associated costs. Specifically, we are requesting approval for an increase in O&M of $592 thousand in 2010 with $402 thousand in the Marketing Department and the remaining $190 thousand in the Human Resources and Operations Governance Department. In 2011, the incremental increase over 2010 is $113 thousand with $83 thousand in the Marketing Department and the remaining increase in Human Resources and Operations Governance. Further details of the increases are provided in the respective department sections following.

TGI believes this request will help to meet the objectives laid out in the BC Energy Plan, to ensure TGI remains compliant with government regulation, and to meet growing customer and stakeholder expectations and should therefore be approved.

(4) CODES AND REGULATIONS

The Utilities Commission Act, Oil and Gas Commission Act, Workers' Compensation Act, Environmental Management Act, Safety Standards Act, fire codes and safety standards, Provincial and Federal Emergency Acts, CSA Codes, and other legislation, regulations and bylaws define TGI's corporate level of reporting and compliance activities. These have been introduced in Part III, Section: A and Terasen Gas' past performance was discussed in Part III, Section B, Tab 1.

To ensure ongoing compliance to existing codes and anticipated new or changed codes, additional operating and maintenance funding is required. There are four main drivers to the increases:

- Inflationary costs (i.e. increased external labour costs, materials costs, etc.);
- Growth (i.e. more services to inspect and maintain, more Rights of Way to clear, more external activity to control and monitor);
- Asset age which increases risk profile (i.e. more frequent inspections, more unplanned maintenance (repair), more replacements); and
- New or changed code requirements.

The reasons for incremental increases, outside of inflationary needs, from the 2009 projection for each of the codes are included in Appendix F-8: Codes and Regulations Details. A summary of associated dollars by code and department is in the tables below.

Table C-6-4: Codes and Regulations Require Additional Funding in 2010

Code ($ thousand)	Distribution	Transmission	Marketing	B&ITS	HR & Gov	Grand Total
BC Safety Authority				410		$ 410
CSA Z246	50	100			10	$ 160
CSA Z662 - Annex M & N	1,412	136	1,000	831	322	$ 3,701
CSA Z662 - Annex A		250		25	430	$ 705
CSA Z1000				11		$ 11
Environmental Management Act					90	$ 90
Power Engineers and Pressure Vessel Safety Act	220					$ 220
Grand Total	$ 1,682	$ 486	$ 1,000	$ 1,277	$ 852	$ 5,297

Table C-6-5: Codes and Regulations Require Additional Funding in 2011

Code ($ thousands)	Distribution	Transmission	B&ITS	HR & Gov	Grand Total
BC Safety Authority			127		$ 127
CSA Z246	(50)				$ (50)
CSA Z662 - Annex M & N	883	1,151	(42)		$ 1,992
CSA Z662- Annex A			100	(90)	$ 10
Environmental Management Act				(20)	$ (20)
Grand Total	$ 833	$ 1,151	$ 185	$ (110)	$ 2,059

Code and regulations compliance forms the foundation of many of our operating programs and activities. Code changes, asset age, asset base expansion and inflation all drive the need for incremental funding to allow the Company to continue to provide natural gas service in the safe and reliable manner that customers have come to expect.

(5) CUSTOMER AND STAKEHOLDER EXPECTATIONS

In Part III, Section A we discussed the impact of government policy, the competitive situation and the economy and how this is not only affecting Terasen Gas directly but how it is affecting customer and stakeholder expectations. We must adapt and change to meet growing customer needs and expectations. TGI must take action to ensure that existing gas customers continue to receive the service they require. TGI must invest in additional human resources to meet growing customer service requirements. And lastly TGI must invest in activities to meet future customer needs. This includes additional sales and account management staff to provide existing and new customers with a suite of energy solutions that not only include gas but also alternative energy solutions.

To meet the changing customer and stakeholder expectations TGI is seeking incremental O&M of $4.5 million in 2010. Of this, the majority (over $4 million) is for additional sales and account management staff, additional staff in government relations, business development and analysis staffing, and additional customer advocacy staff. The remaining amounts are due to increase in staffing in the Regulatory Affairs Department and legal fees required to address regulatory and legislation changes and their impact. In 2011, to meet the customer and stakeholder expectations, TGI requires an additional $0.6 million for additional sales and account management staff in the Marketing Department.

TGI believes that the proposed level of O&M expenses will ensure that Terasen Gas can provide customers with the service they request and require and that Terasen Gas will be able to meet the evolving needs and expectations of communities, stakeholders and policy makers.

(6) DEMOGRAPHICS

Terasen Gas has an aging workforce resulting in a significant attrition risk over the next five years as record numbers of employees become eligible for retirement. This workforce challenge is characterized by a demographic profile which shows that more than 48 per cent of current employees become eligible to retire, with either a reduced or unreduced pension, within the next five years.

Table C-6-6: Large Numbers of Employees Eligible to Retire Within 5 Years

Affiliation	Unreduced Pension Eligibility					
	2009	2010	2011	2012	2013	Total
COPE	60	14	15	14	10	113
IBEW	110	8	15	18	15	166
M&E	28	5	8	7	12	60
Total	198	27	38	39	37	339

Table C-6-7: By Affiliation Employees Eligible to Retire Within 5 Years

Eligbility by Year	COPE		IBEW		M&E		Overall
	Reduced	Unreduced	Reduced	Unreduced	Reduced	Unreduced	
Eligible Prior to 2009	96	42	90	100	24	20	372
Eligible in 2009	-3	18	9	10	10	8	52
Eligible in 2010	0	14	6	8	8	5	41
Eligible in 2011	-3	15	7	15	3	8	45
Eligible in 2012	10	14	1	18	4	7	54
Eligible in 2013	1	10	1	15	4	12	43
Total	101	113	114	166	53	60	607

Note: The number of employees who meet the criteria to retire with an unreduced pension sometime in 2009 are NOT carried forward or included in the numbers for retirement eligibility for 2010 and beyond. Some employees are choosing not to retire when eligible. (Figures do not include executives and are based on HR metrics produced as of December 31, 2008.)

The aging issue is most pronounced with our IBEW workers where 41 per cent of the IBEW workforce is currently eligible to retire with unreduced or reduced pensions.

The Company's retirement risk for 2010 and 2011 is particularly high as a result of some negotiated changes to post-retirement benefits in the new IBEW and COPE Collective Agreements. Generally speaking, unionized employees who retire from the Company and meet certain criteria are eligible for specific health and welfare benefits post-retirement which they continue to receive until their death. During collective bargaining in 2006-2007, the makeup of those post-retirement benefits was changed in a way that many employees deem to be less attractive. These changes take effect January 1, 2011 for IBEW and January 1, 2012 for COPE and create an additional incentive for those employees to retire because in order to remain on the old post-retirement benefits plan, employees who are eligible to retire must do so by December 1 of the year prior.

While the issue of an aging workforce is not a new phenomenon, one factor that has changed significantly is the challenge associated with recruiting qualified employees for many of the specialized positions we require at Terasen Gas. In a labour market where trades, technical and professional skills are in limited supply, and the number of people entering the workforce is still significantly lower than the number of people reaching retirement age, Terasen Gas needs to incur incremental costs over the next two years in order to proactively manage its workforce.

As mentioned in Part III, Section B, Tab 2, there are three areas where the Company requires additional funding over the two-year RRA period to support enhanced efforts to effectively manage the demographic risk. These areas and the associated departments are listed in the following table.

Table C-6-8: O&M Funding is Required to Meet Demographic Challenges

($ thousands)	2010				2011			
	HROG	GS&T	B&ITS	Total	HR	GS&T	B&ITS	Total
Recruiting and On-boarding	50			50				-
Training & Employee Development	226			226	63			63
Transitional Headcount		298	243	541		(31)	183	153
Total	276	298	243	817	63	(31)	183	216

Note: B&ITS - Business and Information Technology Services

Terasen Gas is of the view that these additional costs are reasonable and prudent given the significant implications associated with the demographic challenge.

(7) ACCOUNTING CHANGES

As discussed in Part III, Section A, Tab 11, Canadian accounting standards are now entering a time of unprecedented change. Canadian utilities will be required to comply with IFRS for financial reporting periods commencing on or after January 1, 2011, with comparative figures for 2010 restated to be in compliance with IFRS. Canadian utilities must be ready and able to reflect the 2010 effects of IFRS in both their financial statements and their revenue requirement filings.

A further description of all of the changes related to accounting standards and how they impact areas other than gross O&M is contained in Part III, Section C, Tab 11, Accounting and Other Policies.

Table C-6-9: Accounting Changes Decrease O&M Requests for 2010 and 2011

2010 vs. 2009	**Dist'n**	**GS&T**	**Mktg**	**B&ITS**	**HR**	**Fin/Reg**	**Pres/CEO**	**Total**
Training costs previous capitalized	1,200			1,000				2,200
Feasibility studies previously capitalized				521				521
Inspection costs now capitalized		(1,194)		(60)				(1,254)
Vehicle lease now capitalized	(1,342)	(260)	(20)	(215)	(26)			(1,863)
Changes due to Accounting Standards	**(142)**	**(1,454)**	**(20)**	**1,246**	**(26)**	**-**	**-**	**(396)**
Items properly reflected in CMAE		(225)				(400)	(725)	(1,350)
EEC O&M costs now deferred			(1,596)					(1,596)
External fees previously deferred						201		201
Total Accounting-related Changes	**(142)**	**(1,679)**	**(1,616)**	**1,246**	**(26)**	**(199)**	**(725)**	**(3,141)**

2011 vs. 2010	**Dist'n**	**GS&T**	**Mktg**	**B&ITS**	**HR**	**Fin/Reg**	**Pres/CEO**	**Total**
Training costs previous capitalized	63							63
Feasibility studies previously capitalized			6	51				57
Inspection costs now capitalized		(626)						(626)
Changes due to Accounting Standards	**63**	**(626)**	**6**	**51**	**-**	**-**	**-**	**(506)**

(amounts are in $ thousands)

Note: CMAE – Core Market Administration Expense

Changes to Gross O&M due to Accounting Standards

As a result of changes to Section 3064 Goodwill and Intangible Assets, software-related training costs and costs to investigate the feasibility of various software related options are no longer eligible to be capitalized. In 2009, $1 million of training costs and $521 thousand of feasibility studies in the B&ITS department had been capitalized. These amounts are now required to be expensed as incurred.

International Accounting Standard 16 ("IAS 16") requires that, starting in 2010 for comparative purposes, training costs are specifically excluded from capitalization. In 2009, $1.2 million of training costs were capitalized in the Distribution department, which are no longer eligible for capitalization under IFRS.

However, IFRS recognizes the existence of non-physical components of physical assets, and requires that major inspection and overhaul costs be capitalized and depreciated over the expected time period to the next inspection or overhaul. Both the Transmission and B&ITS (specifically Operations Engineering) departments have major inspections that are now eligible to be capitalized under IAS 16.

Other Accounting-related Changes affecting Gross O&M

- O&M costs in the Gas Supply and Transmission, Regulatory Affairs, and President and CEO departments that are directly in support of the Gas Supply group in supporting core market customers, and are properly recorded as CMAE. Further discussion of these items is included in Part III, Section C, Tab 5.
- Due to IFRS, vehicle lease expenses, previously recorded as an operating lease in O&M and now classified as a capital lease.
- Energy Efficiency and Conservation (EEC) expenditures in Marketing that were previously in O&M and have been approved as part of the EEC deferral account per Commission Order G-36-09.
- In the Finance department, items that had previously been captured in a deferral account during the term of the PBR Period, such as OSC Compliance certification costs, quarterly filing fees, and bond rating agency fees, are now subject to normal accounting treatment as O&M costs.

It is appropriate to reflect these changes to accounting standards and classifications in the Gross O&M costs of the above departments for purposes of the 2010 and 2011 RRA.

(8) SERVICE ENHANCEMENTS

To continue to fulfill our recognized role as a respected and trusted operator providing safe, reliable and cost effective utility service to customers, Terasen Gas forecasts additional O&M funding required for its ongoing operations and activities. These include: increases for contracts to provide services required to support the business operations; maintenance which has been pragmatically deferred during the PBR Period but cannot be deferred any longer; and other increases for such activities as meter exchange appointments, preventive and corrective maintenance and general non-labour inflation for expenses such as cost of gas for own use and electricity to operate compressor stations. These items are described in more detail in the following discussion of the O&M increases by department.

In 2010, Terasen Gas is requesting incremental O&M funding of \$3.6 million, and a further \$1.7 million in 2011 related to these activities.

d) Departmental Overview

The following tables reconcile the O&M incremental funding for 2010 and 2011 by category and by department.

Table C-6-10: 2010 Department O&M Incremental Funding to Meet Business and Customers Needs

Department	*2009 Projection*	*2010 Inter Department Transfers*	Labour Inflation and Benefits	Government Policy	Code and Regulations	Customer / Stakeholder Behaviours and Expectations	Demographics	Accounting Changes	Service Enhancements	Total Incremental	*2010 Forecast*
Distribution	*36,952*	*150*	2,440	-	1,682	-	-	(142)	(28)	3,952	*41,054*
Gas Supply and Transmission	*16,946*	*(83)*	546	-	486	-	298	(1,679)	803	454	*17,317*
Marketing and Development	*66,557*	*(363)*	220	402	1,000	4,026	-	(1,616)	2,023	6,055	*72,249*
Business and Information Technology Services	*39,108*	*60*	1,680	-	1,277	-	243	1,246	3,653	8,099	*47,267*
Human Resources and Operations Governance	*8,445*	*236*	541	190	852	-	276	(26)	216	2,049	*10,730*
Finance and Regulatory Affairs	*9,585*	-	320	-	-	300	-	(199)	(365)	57	*9,642*
President	*17,486*	-	(2,931)	-	-	200	-	(725)	(2,699)	(6,155)	*11,331*
Total (\$thousands)	*195,079*	-	2,816	592	5,297	4,526	817	(3,141)	3,604	14,511	*209,590*

Table C-6-11: 2011 Department O&M Incremental Funding to Meet Business and Customers Needs

Department	2010 Forecast	2011 Inter Department Transfers	Labour Inflation and Benefits	Government Policy	Code and Regulations	Customer / Stakeholder Behaviours and Expectations	Demographics	Accounting Changes	Service Enhancements	Total Incremental	2011 Forecast
Distribution	41,054	-	1,781	-	834	-	-	63	351	3,029	44,083
Gas Supply and Transmission	17,317	-	473	-	1,151	-	(31)	(626)	58	1,026	18,343
Marketing and Development	72,249	-	346	83	-	599	-	6	946	1,980	74,229
Business and Information Technology Services	47,267	-	1,171	-	185	-	183	51	481	2,071	49,338
Human Resources and Operations Governance	10,730	-	537	30	(110)	-	63	-	(13)	507	11,237
Finance and Regulatory Affairs	9,642	-	310	-	-	-	-	-	43	353	9,994
President	11,331	-	726	-	-	-	-	-	(132)	594	11,925
Total ($thousands)	209,590	-	5,344	113	2,059	599	216	(506)	1,734	9,559	219,149

The following sections describe the cost drivers and requirements on a department basis.

(1) DISTRIBUTION

Terasen Gas' customers continue to look to us to provide them with a safe, reliable and cost effective gas service. Distribution is the largest department in the Company in terms of number of employees and plays a major role in prudently managing O&M and capital expenditures to meet the increasing expectations of our customers, regulators and policy makers. Although future Integrated and Alternative Energy Solutions may drive a requirement for maintenance services, there are no Distribution cost-related "asks" for new lines of business for 2010 and 2011. See Part III, Section C, Tab 3, EEC and Alternative Energy Solutions for discussion on proposed deferral treatment of costs and revenues.

The majority of Distribution's resources are focused on operations, maintenance and emergency response activities. However, it should be noted that a significant portion (40 per cent) of Distribution's resources are focused on capital activities such as planning and design as well as installation and renewal of mains, services, meters and other related assets. The Distribution department is organized to maximize synergies between O&M and Capital activities while at the same time maintaining a commitment to providing safe and reliable gas service. This ongoing commitment will serve to benefit stakeholders and customers in the years ahead.

During the first four years of the PBR Period, Distribution maintained the actual level of expenditures (expressed on a per customer basis) well below the level of the 2003 Decision. In 2008 and 2009, cost pressures began to cause substantial upward pressure on O&M per customer and those pressures will continue into 2010 and 2011. In addition new cost pressures have emerged in 2010 and 2011 that will exacerbate the problem.

Table C-6-12: Distribution Forecast O&M 2010 – 2011 vs. 2009P and 2003 Decision

	Decision 2003	Projection 2009	Forecast 2010	Forecast 2011
Distribution Nominal O&M ($ millions)	$ 31.7	$ 37.0	$ 41.1	$ 44.1
Distribution Real O&M ($ millions)	$ 35.7	$ 37.0	$ 40.3	$ 42.4
Real O&M per Customer	*$ 46*	*$ 44*	*$ 48*	*$ 50*

(a) Forecast O&M Expenditures, 2010 - 2011

Looking beyond 2009, Terasen Gas is forecasting the activity levels for Distribution to increase resulting in a corresponding increase in O&M costs. The forecast 2010 and 2011 O&M cost for Distribution are $41.1 million and $44.1 million, respectively. It should be noted that this forecast includes Distribution planned expenditures for shared services provided to TGVI. These costs are prudent and required for Distribution to meet the evolving needs of customers, regulators and policy makers. A forecast of 2010 and 2011 O&M costs is presented in Table C-6-13.

Table C-6-13: Distribution Forecast O&M Expenditures 2009, 2010 – 2011

Function	2009P ($millions)	2010F ($millions)	2011F ($millions)
Field Work	$20.115	$23.170	$25.169
Operations Centre	6.375	7.466	8.032
Asset Mgmt, Regional Mgrs, Process Support	7.113	8.288	9.050
Vice President	4.005	4.418	4.504
Total Distribution (including Vehicle Lease and Fort Nelson)	**37.608**	**43.342**	**46.756**
*Vehicle Lease		(1.612)	(1.977)
**Fort Nelson	(0.656)	(0.676)	(0.696)
Total Distribution (excluding Vehicle Lease & Ft. Nelson)	**$36.952**	**$41.054**	**$44.083**

Notes: * Vehicle lease expenses, previously recorded as an operating lease in O&M are now classified as a capital lease.
** Distribution operates in a manner whereby it treats Fort Nelson simply as a service area within its territory. As Fort Nelson direct costs are included in TGI Distribution detailed budgets they must be removed to create an accurate view of TGI Distribution O&M costs.

(b) Forecast O&M Expenditures by Cost Driver, 2010 - 2011

Looking beyond 2009, a number of cost pressures will result in forecasted increases to O&M budgets. Table C-6-14 and C-6-15 below itemizes the impact of each cost driver against prior year forecasted costs. The major cost escalators are described in greater detail in the subsections that follow.

Table C-6-14: Distribution 2010 O&M Incremental Funding

Department	Labour Inflation and Benefits	Code and Regulations	Accounting Changes	Service Enhancements	Total Incremental	Internal Budget Transfers	Total 2010 Incremental O&M
Distribution	2,440	1,682	(142)	(28)	3,952	150	4,102
Total by Cost Driver ($000s)	2,440	1,682	(142)	(28)	3,952	150	4,102

Table C-6-15: Distribution 2011 O&M Incremental Funding

Department	Labour Inflation and Benefits	Code and Regulations	Accounting Changes	Service Enhancements	Total Incremental	Internal Budget Transfers	Total 2011 Incremental O&M
Distribution	1,781	834	63	351	3,029	-	3,029
Total by Cost Driver ($000s)	1,781	834	63	351	3,029	-	3,029

(c) Labour Inflation and Benefits

Over 73 per cent of the O&M requirements of Distribution relate to labour costs creating a significant exposure to inflationary pressures. Inflationary pressures in excess of CPI will continue into 2010 and 2011.

See Part III, Section B, Tab 02 – the Future for a detailed discussion on this cost driver.

(d) Code and Regulations

Laws, code requirements, and accepted industry operating practices are significant drivers of Distribution O&M costs. As the natural gas industry matures, system age becomes a more prominent consideration with oversight agencies resulting in code enhancements to ensure system integrity is maintained. An example of the significance of changes in laws, standards and codes are the changes to 'CSA Z662 Oil and Gas Pipeline Systems'.

The Canadian Standards Association defines industry standards for a variety of industries across Canada. In particular, Standard 'CSA Z662 Oil and Gas Pipeline Systems' defines how natural gas utilities are to operate from a technical standpoint. The Canadian Standards Association has added the following annexes to CSA Z662 to define what an Integrity Management plan should encompass:

- Gas Distribution System Integrity Management Guidelines;
- Guidelines for Pipeline Integrity Management Programs; and
- Safety and Loss Management.

The Terasen Gas Integrity Management Plan describes:

- Our commitment to keeping pipeline and distribution systems safe, secure and reliable;
- Specific programs and activities to keep distribution systems safe and reliable, and ensuring that they are suitable for continued service;
- Procedures to monitor for conditions that may lead to failures, to eliminate or mitigate such conditions;
- Accountabilities for programs and activities;
- Required records to demonstrate compliance; and
- Formalized employee competency and skill assessments.

Integrity Management is not entirely new to Terasen Gas but the introduction of new CSA Annexes result in a more comprehensive and formalized demonstration of compliance. The operating departments of Terasen Gas will continue to maintain a strong focus on code compliance and will enhance programs in 2010 and 2011 to ensure continued safe and reliable service to our customers.

A detailed discussion on the items noted below can be found in Appendix F-8: Codes and Regulations Details.

Table C-6-16: Distribution Codes and Regulations O&M Cost Drivers for 2010 and 2011 vs. Prior Year

Codes & Regulations Cost Driver	2010 ($ thousands)	2011 ($ thousands)
Security risk assessment	$50	$(50)
Seismic Mitigation	$150	
Integrity management staffing	$215	$185
Class location study	$120	$(60)
Data integrity	$150	
Cathodic Assessment	$80	
Single Point of Failure Analysis	$0	$200
TGVI offset	$(93)	$(33)
Pressure Vessel inspection & maintenance	$50	
Pipeline identification	$100	
Vegetation & Station Grounds management	$175	$50
Bridge and aerial crossing repairs	$30	
Valve maintenance & repairs	$200	
Station Heater Maintenance	$170	
Preventive maintenance	$(117)	$402
Corrective maintenance	$402	$139
Subtotal: Code-Driven	**$1,682**	**$834**

(e) Accounting Changes

Distribution forecasted O&M for 2010 and 2011 is impacted by two accounting charges which are summarized in Table C-6-17 below.

Table C-6-17: Accounting Changes O&M Cost Drivers for 2010 and 2011 vs Prior Year

Accounting Changes	2010 ($ thousand)	2011 ($ thousand)
Training costs to O&M instead of capital (IFRS)	$1,200	$63
Vehicle Lease	$(1,342)	
Subtotal: Accounting Changes	**$(142)**	**$63**

(i) Training Costs

Historically, Distribution imbedded the annual cost of training into the hourly charge-out rate for field employees. As this charge-out rate was applied to both operating and capital work it had the effect of capitalizing a portion of training costs. Distribution field employees charge 42 per cent of their time to capital work; therefore, 42 per cent of annual training costs have historically been capitalized.

The 2010 training budget is $2.8 million. Of this budget 42 per cent or $1.2 million ($2.8 million x 42 per cent = $1.2 million) was previously capitalized and to comply with IFRS accounting standards this amount is now being expensed.

(ii) Vehicle Lease

Vehicle lease expenses, previously recorded as an operating lease in O&M are now classified as a capital lease. A detailed discussion on the items noted above can be found in the earlier discussion in Part III, Section C, Tab 11.

(f) Service Enhancements

Although the customer growth and CPI escalators in the 2004 PBR formula served to offset cost pressures within Distribution, they did not adequately offset all pressures, particularly in the latter years of the 2004-2009 PBR Period. The productivity improvement factor described in the 2004 PBR Period incented Distribution to manage cost pressures and to defer activities and expenditures to the extent it was prudent and safe to do so. Although Distribution continues to be proactive in managing cost pressures, the majority of maintenance activity deferrals or curtailment during the PBR Period can no longer be sustained and emerged as cost pressures in the latter part of the PBR Period as well as into 2010 and 2011 forecasts.

Table C-6-18 below itemizes the Service Enhancements cost drivers compared to prior year projected costs. These cost drivers are discussed in greater detail in the subsections that follow.

Table C-6-18: Distribution Service Enhancements O&M Cost Drivers for 2010 and 2011 vs. Prior Year

Service Enhancements Cost Escalator	**2010 ($ thousands)**	**2011 ($ thousands)**
Electronic Station Charts	$0	$50
Meter exchange	$567	$76
Meter to Cash	$331	$135
Reconnect Fees	($240)	
Emergency Management	$(724)	$136
3rd party damage write-offs	$100	
M&E professional development and M&E relocation	$130	
Communications	$130	
Operations Centre staff	$245	
Line heater fuel	$41	$182
Operations	$122	$54
Distribution Apprentice Training	$(500)	
Incremental Fort Nelson included in above	$(20)	$(20)
Incremental Capital Vehicle Lease Included in above	$(270)	$(365)
Other	$60	$103
Subtotal: Service Enhancements Cost Drivers	**$(28)**	**$351**

(i) Electronic Station Charts

Pressure regulating stations are equipped with chart records that measure and record gas pressures and flows on paper charts. These charts must be changed regularly. We are examining the replacement of this system with electronic charts that may be monitored remotely thereby removing the need to visit the station solely to change charts.

Implementation of the use of electronic charts at stations has the promise of reducing costs associated with chart changing. A study is required to validate the technology and applicability to Terasen Gas facilities.

(ii) Meter Exchange

The forecast level of residential meter exchange activity is driven by the life expectancy of meters and the total size of the meter population. During the PBR Period, Terasen Gas temporarily reduced the number of residential meter recalls to bring the demographics of the meter population in line with a 20 year life expectancy (see Part III, Section B, Tab 1).

Terasen Gas proposes that the residential meter recall schedule target a 20 year meter life span. In addition, a number of poor quality meters are also targeted for recall and retirement. During the late 1990s, certain batches of meters comprised of components constructed with less durable materials were installed within the meter fleet. Although the vendor has since re-designed the meter to address this concern, we believe it is prudent to proactively remove these meters from the fleet to prevent unscheduled failures. As such, the forecasted meter recalls must be increased to 60,000 recalls annually through the period covered by this Application.

Terasen Gas recalls commercial and industrial meters in accordance with Measurement Canada prescribed frequencies, typically every six or seven years for most meter types. Due to a prescribed meter seal life, fluctuations in commercial and industrial customer addition activities from year to year result in a similar subsequent pattern of meter exchanges in future years. Variations of past customer growth has created an echo in the number of industrial meters scheduled for exchange in 2010 and 2011.

We believe the residential and industrial meter fleet management program will ensure customers of Terasen Gas continue to receive service that is both cost effective and reliable.

(iii) Meter to Cash

Meter to cash consists of residential and/or industrial activities related to lock-offs, reconnects, re-reads, high bill investigations and meter investigations. Meter to cash activities grow in step with customer growth although changes to credit and collections processes and other processes associated with technology changes have also resulted in activity level changes. Additional funding is required primarily to support additional meter investigations which are generally initiated by customers.

(iv) Reconnection/Reactivation Fees

TGI plans to increase the reconnection/reactivation charge by $10 effective January 1, 2010. The charge applies to customers who request reinstatement of gas service after being locked-off. The current charge of $55 during business hours and $95 for after hours were established in 2003 and have not been adjusted despite annual increases in labour and vehicle costs due to inflation. Labour inflation has averaged approximately 3 per cent per year over the PBR Period resulting in higher costs to perform these activities.

The new charge will be $65 during business hours and $105 for after hours calls. The additional reconnection revenues expected as a result of this change is $240 thousand.

(v) Emergency Management

Distribution is impacted by variations in synergies as construction and operations activities increase and decrease from year to year. The recent pronounced downturn in new customer additions caused significant loss of synergies and a corresponding increase to first response standby costs in 2008 and 2009 (see Part III, Section B, Tab 1, page 166).

Distribution has reduced the magnitude of this cost pressure in 2010 and 2011 by sharply curtailing work plans previously assigned to installation contractors and by ramping up long term capital programs, specifically hazard mitigation. Distribution will continue to proactively manage this area to minimize financial impacts.

(vi) 3rd Party Damage Write-offs

Terasen Gas incurs costs to repair damages to its system (meters, services and mains) from 3rd party activities. All reasonable attempts are made to recover these costs from the damager (the excavating community, municipalities, and homeowners) where the damager is culpable and identifiable. Collection of these costs is often protracted and involves legal proceedings and payment settlements. The typical cost to make repairs increased in 2007 due to the addition of an apprentice on most repair crews. The crew composition will continue to contain an apprentice for some time as these individuals gain experience in making repairs to the system. Terasen Gas continues to work with the excavating community, municipalities and homeowners to reduce third party damage through specific damage prevention sessions targeting frequent offenders as well as in promoting BC One Call.

(vii) M&E Professional Development and Relocation Fees

Employee development and training is essential to ensure ongoing safe, reliable and cost effective gas service. The demographics of the Distribution M&E workforce requires additional training and employee development costs to replace cumulative years of knowledge and experience as a significant portion of the workforce had reached retirement age. Additionally, as M&E employees retire, increased relocation costs are anticipated to cover the cost of relocating replacements.

Terasen Gas believes that its focus on employee development and training has been a key contributor to the Company's success over the PBR Period. Distribution intends to maintain and enhance its focus in this area to continue its pursuit of Operational Excellence.

(viii) Communications

Communication costs in Distribution are expenditures associated with pagers, satellite phones, cell phones, aircards for mobile laptops, and various other communication devices and systems used across the province. Cost increases are as a result of contract costs, number of users as well as process and technology changes.

(ix) Operations Centre Staff

The process of exchanging residential gas meters requires a brief interruption of gas service followed by pilot light relights for each gas appliance in the home. An increase in residential meter exchange results in a corresponding increase in staffing to make appointments with customers.

To obtain the full benefits envisioned with the implementation of the Distribution Mobile Solution Project (see Part III Section B Tab 1), new staffing is required to develop a Distribution Resource Plan. Key elements of the Distribution Resource Plan are to develop accurate work plans by region and compare to resources available and as work plans change, identify gaps in regional resources early enough to consider all options for mitigation. The Resource Planning Analyst will develop an Annual Resource Plan to optimize synergies for operations, maintenance, construction and emergency standby activities to support our vision of Operational Excellence.

(x) Line Heater Fuel

Line heater fuel is used at pressure reducing stations in the distribution system. The volume of fuel has remained relatively steady and is forecast at 155,000 GJ per year for each of 2010 and 2011. Over the PBR Period, the unit costs for company use gas has steadily risen and Terasen Gas is proposing a revised pricing methodology going forward as part of this RRA (see Part III, Section C, Tab 5, Cost of Gas).

(xi) Operations

A series of surveys are administered and conducted by Distribution to monitor the condition of assets and initiate corrective actions as required. Survey results are monitored closely to: determine asset condition; identify areas of concern; develop and implement mitigation programs; adjust operations frequencies and tasks; and to ensure optimal investment of maintenance resources. As the size of the natural gas delivery system increases through regular customer growth, increased resources are required to conduct the appropriate operations activities.

Operations activities in 2010 and 2011 will ensure Distribution can effectively maintain assets to ensure they are fit for purpose and continue to provide gas delivery safely, reliably and cost effectively.

(xii) Distribution Apprentice Training

Employee development and training is essential to ensure ongoing safe, reliable and cost effective service. The demographics of the Distribution department's workforce has resulted in additional training and employee development costs to replace cumulative years of knowledge and experience as a large portion of the workforce has reached retirement age. Additional Distribution apprentice employees were added mid-2007 and early 2008 to provide for orderly succession planning as retirements increased. Incremental training costs associated with Distribution apprentices are expected to peak in 2009 and are decrease in 2010.

(g) Distribution O&M Summary

The Distribution department will continue to provide the operations, maintenance and emergency response activities critical to providing customers with the safe, reliable, cost effective and environmentally responsible service they expect. Terasen Gas believes the costs outlined in this Application for the provision of these activities are prudent and necessary.

(2) GAS SUPPLY AND TRANSMISSION

The Gas Supply and Transmission ("GS&T") department provides gas supply and transmission system management to ensure reliable, secure and cost effective supplies of natural gas and propane to customers. Despite aging infrastructure, looming retirements, rising gas commodity prices and an environment of increased codes and regulation, GS&T has managed to keep costs, on a real dollar basis, below those granted in the 2003 RRA decision during the PBR Period and for this RRA. Terasen Gas believes the costs presented are prudent and necessary to help to deliver on the goal to ensure safe and reliable gas service for customers.

Table C-6-19 below shows the O&M from the 2003 decision as compared to the 2009 projection and the 2010 and 2011 forecast in nominal and real dollars and real O&M per customer. For the period of the RRA, O&M per customer remains below that of 2003.

Table C-6-19: GS&T O&M Remain Below 2003 Decision Level

	Decision	Projection	Forecast	
	2003	2009	2010	2011
Gas Supply And Transmission Nominal O&M ($ millions)	$ 16.0	$ 16.9	$ 17.3	$ 18.3
Gas Supply And Transmission Real O&M ($ millions)	$ 18.0	$ 16.9	$ 17.0	$ 17.6
Real O&M per Customer	*$ 23*	*$ 20*	*$ 20*	*$ 21*

(a) Forecast O&M Expenditures, 2010 - 2011

Looking beyond 2009, Terasen Gas is forecasting the activity levels for GS&T to increase resulting in a corresponding increase in O&M costs. The forecast 2010 and 2011 O&M cost for GS&T are $17.3 million and $18.3 million, respectively. It should be noted that this forecast includes Transmission planned expenditures for shared services provided to TGVI, cost recovery of which is in the President and CEO's cost center.

A forecast of 2010 and 2011 O&M costs is presented in Table C-6-20 following.

Table C-6-20 – GS&T Forecast O&M Expenditures 2009, 2010 – 2011

Function	2009P ($millions)	2010F ($millions)	2011F ($millions)
Transmission	$15.973	$16.501	$17.400
Gas Supply – Transportation Services	$0.185	$0.192	$0.199
Vice President	$0.788	$0.724	$0.744
Total GS&T	**$16.946**	**$17.317**	**$18.343**

* Excludes vehicle lease costs

(b) Forecast O&M Expenditures by Cost Driver, 2010 - 2011

Looking beyond 2009, a number of cost pressures will result in forecasted increases to forecasted O&M expenditures for Gas Supply and Transmission[182]. These levels of expenditures are required to ensure safe, reliable and cost effective gas service is maintained. Table C-6-21 and C-6-22 below itemizes the impact of each cost driver against prior year forecasted costs. The major cost escalators are described in greater detail in the subsections that follow.

Table C-6-21: Gas Supply and Transmission 2010 O&M Incremental Funding

Department	Labour Inflation and Benefits	Code and Regulations	Demographics	Accounting Changes	Service Enhancements	Total Incremental	Internal Budget Transfers	Total 2010 Incremental O&M
Gas Supply and Transmission	546	486	298	(1,679)	803	454	(83)	371
Total by Cost Driver ($000s)	546	486	298	(1,679)	803	454	(83)	371

182 Core Administration Expense for the Gas Supply department is outlined in Part III, Section C, Tab 5, Cost of Gas.

Table C-6-22: Gas Supply and Transmission 2011 O&M Incremental Funding

Department	Labour Inflation and Benefits	Code and Regulations	Demographics	Accounting Changes	Service Enhancements	Total Incremental	Internal Budget Transfers	Total 2011 Incremental O&M
Gas Supply and Transmission	473	1,151	(31)	(626)	58	1,026	-	1,026
Total by Cost Driver ($000s)	473	1,151	(31)	(626)	58	1,026	-	1,026

(c) Labour Inflation and Benefits

Labour inflation and benefits increases total $0.5 million in 2010 and an additional $0.5 million in 2011.

(d) Code and Regulations

As identified in Appendix F-8: Codes and Regulations Details, the development of TGI's formal IMP gave Transmission an opportunity to review, improve and realign its integrity programs, schedules and spending for optimum results. As a result, TPIP funding requirements decrease over the 2 year Revenue Requirement period, while required funding for other integrity programs increase. The net impact for 2010 is incremental funding of $486 thousand and $1.2 million in 2011.

(e) Demographics

Transmission requires incremental funding to address demographic challenges associated with expected retirements in the 2010/2011 period, a trend impacting the Company as identified on page 353. The funding will be used for knowledge transfer, on-the-job training, and project support.

Transmission is a group of employees with tasks that require a high level of skill and competency that often comes best through direct experience. Retirements involve the loss of decades of intrinsic knowledge and judgment. Transmission has been fortunate in retaining many long-term employees; however, over the Revenue Requirement Period, it is anticipating high turnover due to retirements. In fact, by 2011, approximately one third of TGI Transmission employees will be eligible for retirement with an unreduced pension.

To address these challenges, Transmission proposes to overlap key positions for knowledge transfer, to increase training of junior staff to escalate competency and to update training manuals. The cost of these initiatives has been budgeted at $298 thousand for 2010 with a slight decrease of $31 thousand in 2011.

(f) Accounting Changes

$1.2 million of the $1.7 million reduction is the result of the adoption of IFRS requiring major inspections and overhauls costs to be treated as capital, which is discussed in Part III, Section C, Tab 11, Accounting and Other Policies. As a result, it is anticipated that a large component of TPIP spending in the future will reside in capital budgets. For 2010, $1.2 million moves from O&M to Capital, while in 2011 after rebasing TPIP activities by an increment of $1.1 million in O&M, an additional $626 thousand moves from O&M to Capital.

The TPIP budget has been developed to fund asset assessments and O&M mitigation of corrosion, stress corrosion cracking ("SCC"), and natural hazards (geotechnical, hydrotechnical, and seismic) for Terasen Gas' Transmission pipelines. As the field of integrity management has evolved over the past number of years, so have Terasen Gas' programs and activities to manage and mitigate risk. At the time of Terasen Gas' application for the 2004-2007 PBR Period, a primary focus was on completing baseline in-line inspections ("ILI") for significant transmission pressure pipelines, including retrofits of the Coastal Transmission System to enable pigging. During the 2004-2009 timeframe, Terasen Gas has focused on ILI analysis to optimize re-inspection intervals while also expanding other programs, such as a cathodic protection ("CP") assessment program for non-piggable pipelines.

The programs funded by the TPIP budget are ongoing in nature and will continue into the future. Knowledge of pipeline condition is being enhanced through Terasen Gas' programs, and the proposed budgets have been established at levels Terasen Gas believes are appropriate to complete required activities.

Plans for future TPIP work are evaluated on an ongoing basis using data gathered through TPIP activities. If, for example, digs reveal more or less aggressive corrosion than anticipated, this will be considered along with all other available information for potential adjustment to the timing of the next in-line inspection. The same principle applies to the natural hazards program. Natural forces are not consistent, and some impacts of these forces are more difficult to predict than others. Therefore, it should be noted that all programs funded by the TPIP budget have an element of uncertainty.

Of the remaining $0.5 million reduction in 2010, $225 thousand is for the allocation of Shared Services for CMAE as detailed in the Part III, Section C, Tab 5, Cost of Gas with the remaining $260 thousand for change in accounting treatment from O&M to capital for the vehicle lease.

(g) Service Enhancements

(i) Carbon initiatives

Transmission believes is prudent to continue to undertake initiatives to reduce carbon emissions, aligning with provincial policy initiatives, and with the Terasen Gas' overall Carbon Management strategy. Although Transmission has a very good history of implementing improvements for operating emission reduction, Transmission facilities still account for the majority of company GHG emissions. The optimization efforts to date have been successful, but there are potentially additional opportunities to reduce GHG emissions with changes in legislation. To pursue these initiatives, $100 thousand in funding is required in 2010.

(ii) Transmission Own Use Fuel

Over the PBR Period, the unit costs for company use gas, or own use fuel, have steadily risen due to the increase in market gas prices and introduction of new taxes. Terasen Gas is proposing a revised pricing methodology for company use gas going forward as part of this Revenue Requirements Application (see Part III, Section C, Tab 5, Cost of Gas).

Terasen Gas company use gas is required to deliver natural gas to customers in a safe and efficient manner and it represents a significant cost for Transmission operations. The volume of fuel has increased and is forecast at 110,900 GJ per year for each of 2010 and 2011.

The actual costs for Transmission compressor and LNG plant operations have been increased steadily as a result of increasing fuel costs and new taxes (such as the Ice Levy and Carbon tax). The required incremental funding for 2010 and 2011 over 2009, using the unit costs in Part III, Section C, Tab 5, is $470 thousand and $60 thousand respectively.

(iii) Operations and Maintenance

Additional funding of $230 thousand is required for ongoing operations and maintenance activities for the Transmissions assets. This includes $130 thousand in additional operating costs required for the SCADA system.

(h) GS&T O&M Summary

In summary, outside of inflationary pressures, the main contributors to the increase in 2010/2011 forecast O&M expenditures for GS&T relate to accounting changes, demographics, company use gas (own use fuel) unit costs and code compliance to ensure safe and reliable service.

Having effective gas supply and transmission system management is necessary to ensuring reliable, secure and cost effective supplies of natural gas and propane to customers. The Gas Supply and Transmission department, responsible for managing the supply of natural gas and propane and Terasen Gas' transmission assets, believes the cost presented are prudent and necessary to ensure safe and reliable gas service for customers.

(3) MARKETING AND BUSINESS DEVELOPMENT

As noted in Part III, Section B, Tab 1, the Marketing and Business Development ("MKBD") of Terasen Gas serves as one of the primary interfaces with the public and customers. It consists of the following functions: Customer Information and Education; Customer Solutions and Services; Customer and Business Facilitation; and, Customer Care and Services. Customers require billing and meter reading and we believe they have a right to expect timely and accurate communications. They expect Terasen Gas to advocate on their behalf with stakeholders and government agencies. They also expect the Company to takes appropriate steps to ensure the long term viability of the business and its ability to serve customers effectively.

As noted in Part III, Section A, customer and external stakeholder expectations of Terasen Gas have changed, in some cases significantly, over the period of the PBR Period. Changes in the competitive landscape have increased the risk to Terasen Gas but also create new opportunities. An effective response to these changing circumstances requires an increased level of customer service. It requires investment in investigating and developing new opportunities and services for customers. This increase in costs has been seen in 2008 and 2009 and Terasen Gas sees this continuing in 2010 and 2011. The proposed level of O&M expenses in the RRA for the Marketing and Business Development department will permit us to provide customers with an appropriate level of service, and meet the evolving expectations of communities, stakeholders and policy makers.

Table C-6-23 below shows the O&M from the 2003 decision as compared to the 2009 projection and the 2010 and 2011 forecast in nominal and real dollars and real O&M per customer. For the period of the RRA, O&M per customer remains below that of 2003.

Table C-6-23: MKBD O&M Remain Below 2003 Decision Level

	Decision 2003	Projection 2009	Forecast 2010	Forecast 2011
Marketing Nominal O&M ($ millions)	$ 60.5	$ 66.6	$ 72.2	$ 74.2
Marketing Real O&M ($ millions)	$ 68.1	$ 66.6	$ 70.9	$ 71.4
Real O&M per Customer	*$ 88*	*$ 80*	*$ 84*	*$ 84*

(a) Forecast O&M Expenditures, 2010 - 2011

Compared to the 2009 Projection, O&M costs for Marketing and Business Development are forecasted to increase in 2010 by $5.6 million and $2.0 million in 2011.

(b) Forecast O&M Expenditures by Cost Driver, 2010 - 2011

MKBD will require the forecasted incremental expenditures for 2010 and 2011 which are outlined in the two tables below, followed by a discussion by cost driver of the increases.

Table C-6-24: MKBD 2010 O&M Incremental Funding

Department	Labour Inflation and Benefits	Government Policy	Code and Regulations	Customer / Stakeholder Behaviours and Expectations	Demographics	Accounting Changes	Service Enhancements	Total Incremental	Internal Budget Transfers	Total 2010 Incremental O&M
Marketing and Business Development	220	402	1,000	4,026	-	(1,616)	2,023	6,055	(363)	5,692
Total by Cost Driver ($000s)	220	402	1,000	4,026	-	(1,616)	2,023	6,055	(363)	5,692

Table C-6-25: MKBD 2011 O&M Incremental Funding

Department	Labour Inflation and Benefits	Government Policy	Code and Regulations	Customer / Stakeholder Behaviours and Expectations	Demographics	Accounting Changes	Service Enhancements	Total By Department	Internal Budget Transfers	Total 2011 Incremental O&M
Marketing and Business Development	346	83	-	599	-	6	946	1,980	-	1,980
Total by Cost Driver ($000s)	346	83	-	599	-	6	946	1,980	-	1,980

(c) Labour Inflation and Benefits

For all departments in MKBD, labour inflation and benefits increases total $0.2 million in 2010 and an additional $0.3 million in 2011.

(d) Government Policy

An impact of changes in both energy policy and customer need for more energy knowledge (described previously on page 350) is that customers are increasingly asking for more detailed reports on their usage of gas over past periods, ranging from one to five years. Customers seeking this service are government related bodies such as municipalities, health authorities and government housing, as well as commercial and industrial customers. While some of this information is available online for customers, that information is not sufficiently detailed. It neither contains read dates and degree days, nor is it designed to aggregate consumption from consolidated billed customers.

The Forecasting Analysis and Resource Planning department in MKBD has started to provide customers with one-off usage information. The work is either doing this in house or is completed in conjunction with CWLP to provide extracts. It is currently completed for customers on a best efforts basis when staff have available capacity to complete the work. At present, there is no staff member whose focus is on consumption information requests. The existing staffing level is inadequate to ensure that Terasen Gas can conduct the proper assessments to meet customer needs. As such, we propose adding a staff member in this area to address this need.

In addition to this requirement, we require additional forecasting analysis support for internal and external reporting including, carrying out effective stakeholder consultation and to meeting obligations for regulatory reporting.

To respond to customer needs for more consumption information and additional forecasting analysis support, MKBD requires $402 thousand in incremental funding in 2010 and an additional $83 thousand in 2011. With the new Customer Information System proposed as part of the CCEP CPCN application, some of the consumption information required may be provided by the new system and may possibly reduce the need for an additional person from 2012 forward.[183]

(e) Code and Regulations

One of the Company's main objectives regarding public safety awareness is to support safe, secure and healthy communities by increasing public awareness of gas safety risks and the steps that can be taken to minimize the potential for accidents.

We are proposing to increase the frequency of our current safety communications media plan (radio and print), focused primarily around gas odour and awareness. We request an increase of $1 million for

[183] The CCEP has a planned go-live date of January 1, 2012.

this purpose in 2010. Terasen Gas would continue our existing approach in support of the other safety messages. For background and detailed discussion on this request, refer to Appendix F-8.

(f) Customer and Stakeholder Behaviours and Expectations

As a respected and trusted operator, Terasen Gas believes it must adapt and change to meet growing customer needs and expectations. We must take action to ensure that existing gas customers continue to receive the service they require and that it invests in activities to meet future customer needs. Following is a discussion of the incremental funding TGI requires in order to meet such needs.

(i) Customer Care and Services - Customer Care Contract Management

Customers expect Terasen Gas to provide accurate and timely billing, ensure that meters are read regularly and accurately, provide effective call centre inquiry handling and ensure timely and effective complaint resolution. These activities are performed by the Customer Care and Services group, primarily through the outsourced customer services contract with CWLP and the provision of meter to cash services to CWLP by AUBPOS. In addition, the Customer Care and Services group also manages the BCUC complaint handling process, oversees the mass market bad debt management, Customer Choice program management, performs market research and analysis, and serves customers directly through the construction services call centre. Collectively, this area accounts for the largest portion of the MKBD budget.

TGI has generally met or exceeded targets related to the service quality indicators during the PBR Period, however a number of key indicators did not meet target performance in 2008 and early 2009. In particular, during 2008 and the first quarter of 2009, Terasen Gas has experienced declining performance in key SQI measures that are delivered by AUBPOS under the contract with CWLP. We have also been challenged with the impacts of staff turnover in the AUBPOS Customer Advocacy group, which is focused on addressing and resolving escalated customer issues including complaints to the BCUC.

As a result of the ongoing nature of these challenges, we believe it is necessary, both for Terasen Gas and our customers, to bring additional staff into our contract management team. These additions will increase the employee group from 5.0 to 10.6 FTEs, at a cost of $538 thousand per year going forward. This will enable a higher level of oversight of the CWLP contract in the billing, collections and call centre functional areas to monitor performance and initiate actions to improve that performance. This will also increase the number of Terasen Gas employees dealing directly with customer complaints and billing issues to ensure we have more timely and effective resolution of customer concerns. These changes will also ensure the appropriate level of ownership for key processes and build thorough process knowledge within a broader group at Terasen Gas.

Note that Terasen Gas does not regard the current comprehensive outsourcing arrangement and legacy customer information system platform as a sustainable solution going forward. The Company filed its Customer Care Enhancement Project application on June 2nd, 2009, with the expectation that the new project components will go live on January 1, 2012. Transitioning away from a comprehensive outsourcing arrangement is a critical component of the Company's long-term strategic direction. In the shorter term, as reflected in this Application beginning in 2009 and through the 2010/2011 forecast period, the Company will be increasing its efforts to improve the quality of our customer care activities while bridging to an orderly transition for implementation of the new customer care delivery model effective 2012.

We believe that irrespective of the decision on the CCE Application, these additional resources are required to provide service to levels expected from customers and stakeholders.

(ii) Customer Solutions and Services - Sales, Account Management, and Market Development

As previously noted in Part III, Section A, Tab 2, changing customer requirements driven in part by a changed government policy environment, has affected the nature in which Terasen Gas provides Customer Solutions and Services to its existing customers. For example, it is no longer sufficient for a Commercial and Industrial Account Manager to visit with a customer and speak only about gas. Customers are increasingly looking to Terasen Gas as a source of information and direction on a variety of energy matters. Customers are increasingly looking to find efficiencies for gas, options for alternative energy solutions, partners in alternative energy solutions, detailed information on gas and GHG emissions. As a result, an account manager's duties have expanded, visits with customers are longer, follow-up after visits requires more time, and the account manager's skill set must be expanded. All things being equal, to provide service to the same number of customers, additional account managers are required.

This fundamental change has occurred over only the last five years, and we do not see a return to previous-existing service expectations over the term of the RRA. It will require additional time and resources even to meet the account management needs of existing customers as these customers are now seeking increased levels of service from Terasen Gas. Existing gas customers are also increasingly looking to add or change energy systems to existing building stock, develop new properties with or without gas, and increase their knowledge of energy usage.

In order to meet both growing gas customer needs as noted above and be able to offer additional service offerings including geo-exchange, solar thermal energy, and district/community energy solutions, Terasen Gas seeks approval to increase the number of sales and development staff. These staff will not only sell and develop natural gas offerings but will focus on integrated energy solution offerings that may include any of natural gas, geo-exchange, solar, biomass or other thermal energy sources. The sales and development staff will sell solutions that may increase the natural gas rate base but also add to a rate base for thermal energy delivery. Terasen Gas has already increased staff in this area for 2009 and proposes to continue adding to this area for 2010 with a further slight increase in 2011. This will increase the revenue requirement due to increased labour costs, consulting fees, studies and associated expenses. In aggregate, we require an increase of $3.0 million in 2010 with an incremental addition of $599 thousand in 2011.

(iii) Customer and Business Facilitation

Customer and Business Facilitation includes activities such as community and government relations and policy, and First Nations relations. Staff in this area maintains relations with all levels of government. They advocate on behalf of customers. They analyze and internalize the impact of policy on Terasen Gas and provide input on future policy actions. The group also manages and negotiates operating agreements with municipalities and First Nations groups. Activities in this area are crucial to ensuring that Terasen Gas is able to carry on its business in communities and the areas it currently serves. They ensure that Terasen Gas is visible and its messages are heard. The relationships with communities and First Nations ultimately help to gain support for projects. Existing customers benefit as costs are contained and new customers are added to the system.

As noted in the Part III, Section A the municipal, provincial and federal energy landscape is changing and as such, Terasen Gas must increase its efforts in this area in order to be successful. Specifically, Terasen Gas will be adding resources to these activities to meet increase First Nations requirements, Operating Agreement negotiations, and government policy analysis. Collectively the costs associated with these incremental resources equal $525 thousand for 2010. Terasen Gas believes that these additions will help it be more successful in meeting customers' growing needs while at the same time ensuring that it is also meeting the changing policy environment.

<u>Operating Agreements</u>

Even though Terasen Gas has operating agreements with almost all the municipalities in which it does business, significant time is spent working with individual municipalities to clarify the content of the agreements, the intent of the wording in the agreements and to resolve the payment of any fees associated with agreements.

Terasen Gas was successful in negotiating a significant number of operating agreements over the PBR Period. At the end of 2011, the operating agreements on Vancouver Island will expire and will need to be re-negotiated. In addition there are ongoing requirements to renew TGI agreements as they expire and to ensure that there is a concrete strategy and direction for meeting both the TGVI needs and that of TGI. To meet these needs, additional staffing resources and associated expenses are required. A staffing resource and associated expenses shared between TGI and TGVI will be added in 2010 to meet this need, at a cost of $145 thousand to TGI.

First Nations

As has been shown in Section 3, we believe that over the period of the RRA, there will be a need for greater First Nations engagement. This is primarily driven by fact that the Province of British Columbia and the First Nations Leadership Council have developed a proposal for provincial legislation to recognize aboriginal title in BC and establish a process for negotiation and implementation of shared decision-making and revenue and benefit sharing agreements. The proposed Act would apply to all provincial ministries and agencies and would take priority over all other provincial statutes and policies. This in turn would, and has already started to, change the way that businesses work with and negotiate with First Nations. The provincial legislation to recognize aboriginal title in addition to increased regulatory requirements will result in an increased need for discussions with First Nations each time Terasen Gas proposes to build new infrastructure on Crown lands or through First Nations lands. Lastly, at any given time we are renegotiating agreements with four or more of the 84 First Nations whose land is impacted by Terasen Gas infrastructure. Terasen Gas believes that it requires one additional staff and associated expenses at a cost of $200 thousand, to meet these needs.

Government Policy Analysis and Facilitation

Until the introduction of the 2007 BC Energy Plan, Terasen Gas' interaction with government was primarily with the Ministry of Energy Mines and Petroleum Resources. However, now Terasen Gas interacts with numerous Ministries on both a staff and political level. In order to meet government energy objectives, Terasen Gas must be aware of these objectives and understand both the impact on Terasen Gas and its customers and also determine how Terasen Gas might react to the energy objectives. As such Terasen Gas requires one additional staff and support costs at a cost of $180 thousand in order to meet these changed objectives.

(g) Accounting Changes

The decrease of $1.6 million reflects the Energy Efficiency and Conservation (EEC) expenditures in Marketing that were previously in O&M and have been approved as part of the EEC deferral account per Commission Order No. G-36-09.

(h) Service Enhancements

Additional funding of $2 million in 2010 and $0.9 million in 2011 is to support ongoing activities within MKBD with a significant portion of the increase for the CWLP contract which covers billing, meter reads, and call centre handling. Terasen Gas' contract with CWLP has inflation factors built into the cost structure and therefore is committed to paying CWLP fees for 2010 and 2011. Based on the current customer forecast, increases of $793 thousand in 2010 and $956 thousand in 2011 are forecasted. The CWLP contract increase in 2011 accounts for the entire increase forecasted in this category for 2011.

The remaining $1.2 million of incremental funding include $300 thousand for increased market research and support, $300 thousand for the Construction Services – Contact Centre, $300 thousand for Communications resources and $300 thousand for Business Development support.

(i) Customer Care and Services - Market Research

This group's activities are primarily to support the rest of the Company in the collection and analysis of market information. Examples of research activities or services provided include:

- Large Commercial Customer Satisfaction Study, Small Commercial Customer Satisfaction Study
- Builders and Developers Study, Residential End Use Study ("REUS"), Corporate Image Study, Ad Tracking Study, Customer Satisfaction Tracking Study, Residential Customer Satisfaction Study
- Customer Information System Focus Groups, Stable Rate Completion Study, Safety Awareness Study, Customer Choice 2008 Ad Evaluation Focus Groups, Planners Study

These activities are vital to Terasen Gas' ongoing business activities. They provide the information necessary to ensure that Terasen Gas is understanding and meeting customer expectations, identifying product and service development opportunities, and monitoring the performance and effectiveness of customer information programs. This provides internal departments with the information so that Terasen Gas can adapt to the changing business environment.

We will increase the frequency with which we survey customer usage via the REUS. Previously, Terasen Gas had completed this activity every five years. However, with the recent pace of change in the energy marketplace, five years between studies is too long. Up-to-date customer data is important to inform and develop new programs or service offerings. We will complete smaller, more focused REUS studies on a more frequent basis. This will add to the cost for completing REUS studies.

In addition, we propose to increase spending on energy industry information services, specifically the energy utility industry. Similar to the REUS spending increases, this will help us better understand what core services our customers want, meet regulatory filing information requests and provide internal departments access to information that will help in product and service development. Collectively these changes to information requirements will result in an increase of $300 thousand.

(ii) Customer Care and Services - Construction Services - Contact Centre

This group's activities are to primarily act as the call centre for customers ordering construction services, for what Terasen Gas terms simple Service Line installations. These services include new service installations, requests for service alterations and requests for service abandonment (removals). This group was previously part of the Distribution Operations department. It was moved into the Marketing Department in 2006 to bring groups with a primary responsibility for direct customer interface under common management. The Contact Centre receives on average 60,000 inbound calls a year and makes an average of 36,000 outbound calls for follow up information.

Activities in this department during the 2003-2008 timeframe have changed as the group and its activities have evolved. During the high building volume experienced in 2007, it was determined that capitalization was to be 75 per cent and O&M to be 25 per cent. In 2009, we reassessed the activities of this group and determined that the split between O&M and capital should be 50 per cent Capital and 50 per cent O&M. This change will add approximately $300 thousand to the O&M costs in 2010 over 2009, but reduce capital costs and therefore long term ROE and debt costs paid by customers.

(iii) Customer Information and Education

Customers expect timely and accurate communications from Terasen Gas. Through our Customer Satisfaction research, we have learned that our customers value receiving information from us to help educate them on rates, energy efficiency, the Customer Choice program and other energy options, safety and our involvement in BC communities.

We require additional funding to support Customer Information and Education to meet: the changing energy needs of our growing customer base; governance requirements; the language needs of a diverse demographic customer base; and, the increasing requirements as a result of provincial energy policy.

Terasen Gas has already added two additional staff in 2009 to this area to meet these ongoing needs, and additional incremental funding for these staff requirements is sought in 2010 and 2011. In addition, we require additional funds to support ongoing media monitoring and newswire services to reflect the increased media interest in energy and the greater requirements on Terasen Gas to provide this information. Together this 2010 incremental funding equals $300 thousand, with no further increment required for 2011.

We believe that these additional funds are required to continue to provide customer information and education to our customers and to internal departments of Terasen Gas. Without ongoing investment in customer information and education, Terasen Gas expects customer complaints (those directed internally and also to the BCUC) to increase, customer satisfaction levels to drop and customer awareness of rates, safety, emergencies and related items to decline.

(iv) Business Development Support

Presently, the costs associated with resource planning are accounted for in the Core Market Administration budget within the Gas Supply group. The costs for 1.5 FTE are now being moved out of this budget and into the O&M budget. This will have no long term impact on customer costs as the change is from one cost centre to another. However, the impact to the O&M budget will be an increase of $300 thousand in the Business Development group.

(v) Bad Debt

As was shown in Part III, Section B, Tab 1, the changes in bad debt management processes and the strong economy have led to lower bad debt experience rates over the term of the PBR Period. For the majority of the PBR Period, British Columbia, and the rest of Canada, was enjoying a time of prosperity. However, starting in late 2007, manufacturing and specifically forestry related industries started feeling the pressures of the collapsing US housing market. As noted in the 2008 and 2009 annual reviews, many forestry companies have since scaled back their activities and as a result reduced the number of employees. The financial crisis in late 2008 has also taken its toll. British Columbia, while somewhat sheltered by Olympic activity, has also seen unemployment rates increase from 5.3 per cent in December 2008 to a seasonally adjusted rate of 7.4 per cent in April 2009. With the economy contracting, an increase in bad debt is likely to occur. Terasen Gas believes it is prudent to keep the bad debt experience rate at 0.35 per cent of revenues for mass market customers. At this time, this is forecast to equate to $4.9 million in each of 2010 and 2011.

(i) Marketing and Business Development O&M Summary

The proposed level of O&M expenses in the RRA for the Marketing and Business Development department will ensure that Terasen Gas can provide customers with the service they request and require and enable Terasen Gas to meet the evolving expectations of communities, stakeholders and policy makers.

(4) BUSINESS AND INFORMATION TECHNOLOGY SERVICES

The mandate of the B&ITS department is to provide support services to other departments of the Company. B&ITS is organized into three distinct groups – IT and Business Services, Operations Engineering and Operations Support. The functions and responsibilities of each of these groups were described in the Part III, Section B, Tab 1, Management Excellence section.

During the PBR Period, B&ITS has relied on significant efficiency gains to offset cost pressures, helping to contain its O&M costs. On a real dollar basis, 2009 projected costs, both on a total O&M dollar basis and on a per customer basis are below that provided for in the 2003 decision. However, B&ITS is now at a point where the forecast 2010 and 2011 O&M costs are expected to increase significantly due to a number of drivers.

Table C-6-26: B&ITS O&M will Experience a Significant Increase in 2010

	Decision 2003	Projection 2009	Forecast 2010	Forecast 2011
IT and Business Services Nominal O&M ($ millions)	$ 35.4	$ 39.1	$ 47.3	$ 49.3
IT and Business Services Real O&M ($ millions)	$ 39.9	$ 39.1	$ 46.4	$ 47.4
Real O&M per Customer	*$ 52*	*$ 47*	*$ 55*	*$ 56*

(a) Forecast O&M Expenditures, 2010 - 2011

O&M costs are forecasted to increase in 2010 by $8.2 million and $2.1 million in 2011, with the majority of the increases in IT and Business Services and Operations Engineering.

Table C-6-27: B&ITS O&M Increases by Department

Department	2009 Projection ($millions)	2010 Forecast ($millions)	2011 Forecast ($millions)
IT and Business Services	$ 22.4	$ 27.7	$ 28.9
Operations Engineering	9.2	11.4	12.1
Operations Support	7.5	8.5	8.8
Total B&ITS (including vehicle lease)	**39.1**	**47.5**	**49.7**
Vehicle lease		(0.2)	(0.3)
Total B&ITS (excluding vehicle lease)	**$ 39.1**	**$ 47.3**	**$ 49.4**

(b) Forecast O&M Expenditures by Cost Driver, 2010 - 2011

In order to meet the mandate to provide support services to other departments of the Company, B&ITS will require the forecasted 2010 and 2011 incremental expenditures compared to the prior year forecast. These are outlined in the two tables below followed by a discussion by cost driver of the increases.

Table C-6-28: B&ITS 2010 O&M Incremental Funding

Department	Labour Inflation and Benefits	Code and Regulations	Demographics	Accounting Changes	Service Enhancements	Total Incremental	Internal Budget Transfers	Total 2010 Incremental O&M
IT and Business Services	582	116	76	1,000	3,394	5,168	127	5,295
Operations Engineering	560	1,136	167	363	(200)	2,026	-	2,026
Operations Support	538	25	-	(117)	459	905	(67)	838
Total by Cost Driver ($000s)	1,680	1,277	243	1,246	3,653	8,099	60	8,159

Table C-6-29: B&ITS 2011 O&M Incremental Funding

Department	Labour Inflation and Benefits	Code and Regulations	Demographics	Accounting Changes	Service Enhancements	Total Incremental	Internal Budget Transfers	Total 2011 Incremental O&M
IT and Business Services	334	2	-	-	503	839	-	839
Operations Engineering	482	83	183	51	(22)	777	-	777
Operations Support	355	100	-	-	-	455	-	455
Total by Cost Driver ($000s)	1,171	185	183	51	481	2,071	-	2,071

(c) Labour Inflation and Benefits

For all departments in B&ITS, labour inflation and benefit increases including seniority related step increases for unionized staff total to $1.7 million in 2010 and an additional $1.2 million in 2011. As mentioned on page 349 labour inflation in 2010 and 2011 is forecasted at 3 per cent per year for all categories of employees. In 2010, benefits are forecast to increase, driven primarily by pension costs which are expected to increase significantly as a result of declining investment returns.

(d) Code and Regulations

To comply with existing codes and anticipated new or changed codes, additional funding of $1.3 million in 2010 and $0.2 million in 2011 is required. The codes and regulations, and how they affect our operations, are discussed below.

(i) Operations Engineering

Of the $1.3 million in 2010, the majority $1.1 million is in the Operations Engineering group. Response to changes in codes and regulations is the largest cost driver of forecasted O&M cost increases in Operations Engineering. Changes in the BCSA – Gas Safety Regulation and CSA Z662 are driving significant increases in future O&M costs to ensure regulatory compliance.

BCSA

As of April 1, 2008, the BCSA has changed the Procedures for Excavations section of the Gas Safety Regulation requiring Terasen Gas to provide information requested within 2 business days. Terasen Gas has been working at meeting this requirement since its introduction and will require additional resources. In order to ensure that we meet the two day turnaround requirement, Terasen Gas will be required to increase staffing levels at a cost of $410 thousand in 2010 and an additional $128 thousand in 2011.

CSA Z662

The Canadian Standards Association (CSA), with input from industry, is shifting the long-term direction of Canadian pipeline regulation to make it more performance-based and less prescriptive. This shift is evident throughout CSA Z662 and continued to be reinforced through the introduction of Annex N and M in 2006. In 2007, a new clause was added to the Operating, Maintenance, and Upgrading section of CSA Z662 that moves industry further towards performance based regulation. As a result, we are required to respond to this new regulation and require $150 thousand increased funding in 2010 to implement and manage our coordinated compliance with key sections of CSA Z662 related to performance based regulation.

With the adoption of CSA Z662 Annex N and M, regulators have raised the formality and rigor around competency and training requirements for employees and other workers who impact asset integrity through their work. Clause N7.1 states that "operating companies shall develop and implement competency and training requirements for company personnel, contractors, and consultants to give them the appropriate knowledge and skills for performing the elements of the pipeline integrity program for which they are responsible". Staffs in Operations Engineering have been identified as performing elements of the pipeline integrity program. As a result, increased O&M funding of $109 thousand in 2010 and $20 thousand in 2011 is required for administering the competency and training model to our technical staff.

The adoption of CSA Z662 Annex N also brought more formal and rigorous requirements to the records management practices. As part or our response to this new regulation, we have determined that we will need to incur incremental costs in 2010 and 2011 in order to comply with the specific requirements of Annex N, Section N.6 - Pipeline integrity management program records. $56 thousand is requested in 2010 to transfer the critical cathodic protection records from DNV to the Terasen Gas AMFM system. DNV is the current contractor for managing Terasen Gas' cathodic protection systems in the Interior. Transferring the data will ensure that Terasen Gas has records of all of our cathodic protection systems in the AMFM system and are in compliance with Annex N.6.1(j). In addition, funding of $60 thousand for records support staff will also be required.

Cathodic Protection

TGI will invest in CP and corrosion prevention. While CP has been applied for decades, Terasen Gas and other pipeline operators have continued to take steps to improve comparisons of measured CP system performance against industry established criteria and standards. These changes will improve confidence levels that CP systems are effectively mitigating corrosion and preventing premature degradation of installed pipelines and, at the same time, result in increased workloads and cost.

TGI is seeking a $212 thousand increase in 2010 for the Corrosion group to perform necessary work associated with regular surveys and electric shorts, a one-time additional CP survey and incremental electrical costs associated with the operation of the rectifiers that induce the required cathodic protection. For 2011, there is a $50 thousand decrease as funding for the CP survey in 2010 is not required in 2011.

Right of Way

In order for Terasen Gas to satisfy new requirements and to maintain compliance with existing requirements, the Operations Engineering O&M budget needs to be increased by $108 thousand in

2010 and by $15 thousand in 2011. This increase will allow Terasen Gas to pay rising costs associated with easement or ROW fees, vegetation management, and a formal public awareness program.

Odorant

As a safety measure, we are required under CSA Z662 to odorize the natural gas we distribute to customers. The total annual cost of odorant is expected to increase by $31 thousand in 2010 and by another $10 thousand in 2011 because of the projected increases in the price of the commodity.

(e) Demographics

Both the Operations Engineering and the Facilities departments will require incremental funding in 2010 and 2011 to manage the aging workforce within their respective areas.

Facilities require increased funding of $76 thousand for a transition headcount in 2010 to ensure knowledge transfer and planning for replacement of a retiring employee in 2011. Facing a number of retirements in the next several years, the Operations Engineering department will require increased funding of $167 thousand in 2010 and another $183 thousand in 2011 to be successful and proactive in transferring of knowledge, skill and work from the retiring employees.

(f) Accounting Changes

Accounting changes of $1.2 million in 2010 consist primarily of $1 million in the IT department related to accounting standard changes. As part of Canadian GAAP changes, certain costs that have been traditionally capitalized are now required to be expensed. These include any costs incurred in the development of business cases, training, training material, change management activities and general administration costs. These costs vary from project to project but Terasen Gas feels it is prudent to cap these costs at 5 per cent of the capital spend which would be $1 million for both 2010 and 2011. Terasen Gas is of the opinion that this number is probably optimistic but will commit to managing all expenditures within this cap.

Similarly, $521 thousand is forecasted in 2010 and a further $51 thousand in 2011 in Operations Engineering for costs related to preliminary investigation and training activities which are required to be expensed under the Canadian GAAP changes. This is offset partially by a decrease of $215 thousand for the change in accounting for vehicle leases and a $60 thousand decrease resulting from higher charge-out to capital for meter dismantling activities.

(g) Service Enhancements

In 2010, $3.6 million will be required with another $0.5 million in 2011. These costs are described below.

(5) BUSINESS AND IT SERVICES

Of the $3.6 million increase identified for 2010, $2.8 million is for the IT department which includes $1.7 million for IT contract driven increases. IT contractual obligation increases include annual licensing fees associated with software used to support the business processes and agreements with third parties for the support and maintenance of the Company's applications.

(a) IT Department

IT Contract Increases

Of the $1.7 million for IT contract driven increases in 2010, $372 thousand is attributable to a change in software licensing models from various vendors, $461 thousand for application support, $677 thousand for supporting increased headcount, upgrading capacity for existing infrastructure and IT security, and $190 thousand for pre-buy of software under multi-year support contract and Telus consulting.

SAP is the core business application that supports the Company's financial, supply chain, Human Resources, Pay/time, Work Management, Preventive Maintenance and Meter Management business processes. In the third quarter of 2008, SAP announced it was changing its licensing support structure (called "enterprise" support) which enhances the support model, but at an incremental cost of 5 per cent on all capital investment in SAP products. The implementation of the increase is phased over a couple of years with the intent on reaching full costs for 2012. In 2010, the incremental cost is $244 thousand. Other software vendors such as Oracle and GE Smallworld have implemented other licensing models which resulted in higher costs, albeit not as a significant increase. There are incremental licensing costs based on increased user numbers as well as increases in the US dollar exchange rate. The increase for 2010 is $128 thousand. The overall software licensing is expected to increase another $45 thousand in 2011.

$461 thousand in 2010 is for an incremental two FTEs in support from third parties due to the increase in the number and variety of skills required to support the applications as well as meeting the service level requirements of the operating departments. This is expected to increase another $123 thousand in 2011.

$677 thousand in 2010 is for supporting increased headcount and filling of vacancies that were filled over the last year, increases in infrastructure to support the new applications, upgrades to capacity for existing infrastructure as well as the ever increasing costs of security.

$190 thousand is for Telus consulting and pre-buy of software under multi-year support contracts. Included in the 2010 numbers compared to 2009 is the renewal of license support that Terasen Gas "pre-bought" in 2008. Pre-buy occurs when a vendor offers a multi-year support contract. The effect of this has reduced the 2009 expenses by $90 thousand for software compliance, however the support costs will result in an increase in 2010.

Other IT Increases (total of $1.1 million for 2010)

Five additional FTEs at a cost of $631 thousand will be required in 2010. Two FTEs are required for business intelligence support. Currently Terasen Gas has only one person responsible for the development and support of the SAP reporting platform and one person dedicated to work with the business in requirements support. The additional FTEs are required to ensure that adequate support to the business both in addressing the increased demand for information, as well as risk mitigation in the event that either of the incumbents is unable to work or leaves the organization. The resulting gap of in-house expertise would have to be met with outside consulting at a much higher cost. A third headcount is to provide a second business planning analyst for the same rationale as above. The fourth headcount is for a Project Manager position to manage the development and implementation of IT capital projects. The fifth addition is for IT Technician position to provide support for areas not covered by the Telus contract such as system administration for infrastructure systems, project and documentation support, and request for IT services from the departments.

In addition to the above, $500 thousand will be required in 2010 to support the incremental operating expense associated with new IT capital initiatives. $375 thousand is for Disaster Recovery Planning ("DRP") with an additional $375 thousand anticipated in 2011. The majority of the expenditures are required to address infrastructure and risk mitigation initiatives associated with upgrades in security and in support of business applications (technical upgrades, vendor support issues, etc). This is expected to increase another $600 thousand in 2011 for new IT capital projects.

Terasen Gas is becoming increasingly dependent on information technology to drive efficiencies in the business and offer superior service to its customers. The speed and complexity with which the IT industry moves offers a constant challenge to the IT department to keep up with industry changes. There are ever increasing security threats and increasing requirements for department support services.

We are also impacted by new regulations for cost transparency and the adoption of changing accounting standards.

IT is constantly balancing all of these factors to find the appropriate balance of cost, risk mitigation and service. The forecasted incremental IT expenditures are required in order to manage, maintain, and support the IT infrastructure of the Company.

(b) Facilities

Of the $3.6 million increased identified for 2010 for B&ITS in this category, $572 thousand is for Facilities. We require an additional headcount at a cost of $74 thousand to meet the operational demands for day-to-day break/fix activities required to maintain the aging facilities. Increased building maintenance activities and lease costs total $358 thousand. In addition, the Surrey Operations Centre will need to be reorganized at a cost of $140 thousand to accommodate the expected headcount increases.
For 2011, the $300 thousand decrease is due to removal of the $140 thousand for reorganizing at Surrey Operations Centre and $160 thousand of the building maintenance added in 2010.

(c) Operations Support

O&M costs within Operations Support for Service Enhancements are driven by several critical activities conducted on behalf of Terasen Gas including management of the company's meter fleet and delivery of mechanical, instrumentation, radio network, and supply chain services to the operating groups. As such, future increases of $459 thousand for O&M expenditures are related to the enhancement of these existing services. The enhancement of these services is necessary to ensure continuation of safe, reliable and cost effective service.

Of the $459 thousand increase required, specific items include $160 thousand for tools and equipment maintenance, $110 thousand as a result of declining revenues from 3rd parties for meter server services, and $170 thousand for meter services provided to TGVI. The $170 thousand represents no net increase to overall TGI O&M, as it is a transfer of the recovery for such services from Operations Support to the President and CEO's cost centre under a Shared Service agreement.

In 2011, a $100 thousand increase will be required for mobile radio network costs. Terasen Gas currently owns and operates a mobile radio network throughout its coverage territory within the BC Interior and Lower Mainland but has not deployed this capability along the corridor between Squamish and Whistler or on Vancouver Island. We believe that expanding our mobile communications network throughout the entire coverage territory of Terasen Gas will provide a common platform for emergency communications throughout the province that is essential for operations. The current cellular network used for communications within TGW and TGVI does not have adequate coverage throughout these two regions. Furthermore, the supplier cannot provide assurance that cellular communications will be available in a widespread emergency. As such, the risk profile is significantly increased in these regions as any loss in cellular service during an emergency may result in a reduced ability to respond to immediate threats to the public or employees.

The Operations Support forecasted incremental costs are necessary to allow Operations Support to continue to serve the Operating Groups in a safe, reliable, and cost effective manner.

(d) B&ITS O&M Summary

The proposed level of O&M expenses in the RRA for the Business and Information Technology Services department will ensure that the necessary support services are provided to other departments of the Company.

(6) HUMAN RESOURCES AND OPERATIONS GOVERNANCE

The HROG department is made up of the following functional areas:

1. Human Resources (HR Strategy and Advisory Services, Leadership Development, Employee Training and Development, Recruiting, Labour Relations, Short and Long-term Disability Claims Management, Pension and Benefits, Compensation, Employee Wellness, Payroll, Employee Services and Human Resources Information System ("HRIS"))
2. Employee Training and Development (Trades and Non-Trades Training, Management Training, Engineers-in-Training, Training Records)
3. Environment, Health and Safety (Environmental Affairs, Occupational Health and Safety, Emergency Preparedness, Corporate Security, Public Safety)
4. Engineering Governance (Corporate Standards, Approved Products, Incident Investigations)
5. Enterprise Risk Management and Insurance (Corporate Insurance Programs and Contracts, Disability Management, Enterprise Risk Management, Fleet Services)

Table C-6-30 below summarizes the 2003 decision, 2009 projection and 2010 and 2011 forecast O&M for HROG in nominal and real dollars, and on a per customer real dollar basis. On a real dollar basis, 2009 projected costs, both on a total O&M dollar basis and on a per customer basis are below those provided for in the 2003 decision. With changes in code and regulations and the need for Terasen Gas to remain competitive in attracting skilled workers, HROG O&M costs are expected to increase in 2010 and 2011.

Table C-6-30: HROG O&M Increasing to Respond to Evolving Needs

	Decision 2003	Projection 2009	Forecast 2010	Forecast 2011
Human Resources Nominal O&M ($ millions)	$ 8.1	$ 8.4	$ 10.7	$ 11.2
Human Resources Real O&M ($ millions)	$ 9.1	$ 8.4	$ 10.5	$ 10.8
Real O&M per Customer	*$ 12*	*$ 10*	*$ 13*	*$ 13*

(a) Forecast O&M Expenditures, 2010 - 2011

HROG O&M costs are forecasted to increase in 2010 by $2.3 million and $0.5 million in 2011. As context for the forecast increase in funding in 2010 and 2011, the following is an overview of the various departments within HROG and their goals and objectives in the coming years.

(b) HROG Overview and Priorities

(i) Human Resources - Goals and Objectives

The overall goal of the Human Resources function is to ensure that the Company's workforce, now and into the future, is of a quality and quantity to enable the achievement of the Company's business goals and objectives. Notwithstanding the recent economic downturn, the Company is entering a critical stage in a labour market that is challenged on two fronts, by an aging workforce and a limited supply of younger, skilled workers graduating from trades and technology programs. In order to remain competitive and continue to grow its business, TGI needs to strengthen the foundation of its end to end Talent Management systems and processes. This need lies at the heart of the long-term Human Resources vision to "Retain, attract, develop and motivate the right people to achieve desired business results". Our success in achieving this vision rests on the following four key strategic pillars:

1. Retain, attract and motivate employees;
2. Invest in our employees;
3. Make Terasen Gas a preferred place to work; and
4. Enable business success.

Each of these pillars relies on effective processes, system capabilities, and programs to ensure TGI's people practices support the Company's business goals. In order to achieve this TGI plans to:

- Implement strategically targeted recruiting activities;
- Create a better understanding of career paths and development opportunities throughout the organization;
- Provide clear individual growth opportunities in the form of:
  - Skill based career paths which are developed and communicated for all employees;
  - Career growth and development opportunities which are aligned with the competency framework set out under the Competency and Leadership Development sections below.
- Develop targeted skills and knowledge to ensure all employees are well equipped for their roles by developing and maintaining: competency assessments, knowledge base; appropriate standards; training modules, and a data capture (warehouse);
- Enhance performance management by aligning team and individual goals with corporate goals and strategy; standardizing employee reviews and appraisals, motivating desired behaviours; and ensuring performance and development plans are integrated with competency assessments;
- Provide robust succession management by leveraging system enhancements for capturing succession data to effectively plan talent needs, identifying gaps and retaining the highest performers;
- Offer competitive compensation by tying compensation to performance, benchmarking against external market data, maintaining internal equity, and ensuring total compensation is meaningful and diversified;
- Provide an enhanced course delivery methodology to reflect emerging learning styles including e-learning, and web-based, gaming or simulation-based learning;
- Create and document a process for knowledge asset management and transfer by:
  - Leveraging competency and skills repositories; and
  - Maintaining a standard method of identifying, developing, applying, measuring, reporting, auditing and managing the investments in critical knowledge assets within the organization (i.e. Learning Management System).
- Provide real-time access to information for management and employees;
- Leverage technologies to reduce labour intensive processes such as:
  - Online performance management;
  - Smart forms;
  - Job market data/job evaluations;

- o Employee/manager self-serve; and
- o Enhanced reporting.

In short, TGI must continue to invest in the development of its employees and address the demographic shift that its business will experience if it is to maintain the safe, secure, and reliable service customers expect.

(ii) Employee Training and Development – Goals and Objectives

The Training Department has historically provided training to field employees only, and record-keeping has been limited to attendance records. The newly named Employee Training and Development department is moving toward becoming a full-service employee development group that will work with the business to:

- Help managers understand the development needs of their employees;
- Determine the type of training best suited for the particular need (i.e. internal v. external service provider, instructor-led vs. e-learning);
- Develop learning objectives, standardize course content and secure and catalogue the content for consistency; and
- Deliver training.

The Employee Development group is responsible for providing the following expertise and resources:

- Managing the data in the Learning Management System
- Managing and delivering the training required for trades-related field activities
- Developing curricula and managing the training content
- Determining the best methods for training in areas other than trades-related field activities, and assisting in the development and delivery.

For trades-related training, TGI will continue to provide Instructors because of the uniqueness of the business. As TGI transitions to a full service employee training and development model, the Employee Development group will work with the business to identify who is best suited to provide the instruction. In many cases, the training is best delivered by subject matter experts (often work leaders and/or senior employees). The Employee Development group will provide courses that focus on 'Training the Trainer', and will support these peer trainers to ensure that the content is delivered in an effective manner. In some cases, TGI may need to contract with an external service provider to best meet the Company's training needs. The Employee Development group will ensure consistency in quality and cost for these contract resources.

Competency Management

The main shift in focus for the Employee Development group in particular, and for the Company as a whole, is a move toward managing competencies and away from managing training records. The Company must still maintain a robust system of record keeping, but the emphasis will shift to managing competencies. As discussed in the Codes and Regulations section on page 351, the primary driver for this shift in focus is that the Oil and Gas Commission has adopted new regulations in CSA-Z662 Annex N (Integrity Management Programs). This Annex requires TGI to demonstrate competency for integrity-related tasks (or "covered tasks"). TGI's Competency and Training project is currently developing a technology solution that will allow it to meet the compliance requirements for Annex N. The project is using SAP as a platform to develop a Learning Management System, as well as to define the required competencies for the covered tasks. This Competency Model (or Framework) will eventually be used across all areas of the Company. This Competency Model is based on defining the required competencies for each job, and then assessing employees against the required competencies for their jobs to determine where the gaps are and how best to fill those gaps, including additional training.

With the demographic challenges that face us in the coming years (see Part III, Section B, Tab 2) it is critical that the Company have a system for identifying the competencies required to run its business and for effectively transferring knowledge from current employees to new employees. Our customers will benefit because the new competency model allow the Company to maintain a robust system for ensuring that new workers are knowledgeable and efficient. As more and more new employees are hired to replace retiring employees, Terasen Gas will lose its ability to rely on the years of experience particular employees have gained on the job. The Company must have processes and systems in place that will allow it to:

- Define the required competencies for each job;

- Assess individual employees against those required competencies; and
- Address any deficiencies through appropriate training in a timely manner.

The Company will be required to develop and maintain a Competency program. Managing these competencies will have a significant effect on the way the Company delivers training in the coming years. Once the project is completed, sustaining the Learning Management System and the competency-related processes will require additional human resources.

Leadership Development

Employee development is a key pillar of Terasen Gas' HR strategy. In addition to traditional training and development opportunities for field and office workers, TGI has recently renewed its emphasis on leadership development across the organization by focusing on the development of emerging leaders who have been identified through the succession planning process. Targeted coaching, training, mentorship, and leadership programs are being introduced to build leadership bench strength across the organization. A new Manager-in-Training program is being piloted to expose aspiring managers, both internal and those recruited externally from other industries, to various functional areas of our business to give them a broad overview of our operations and better position them for a career in management.

A leadership development framework is being built on the principles of "Learn, Grow, Lead" as well as development options that focus on Leading Self, Leading the Business, and Leading Teams. Developing emerging leaders is a natural extension of the Company's succession planning process and will be aligned with the following redefined Terasen Core Leadership Competencies:

Business Competencies	**Personal Competencies**
• Business Acumen	- Working Relationships
• Customer Focus	- Decision Making
• Strategic Alignment	- Leading (Self & Others)

Employees also have the opportunity to access a variety of funding support mechanisms to support their personal and professional development including tuition support for undergraduate and graduate degree programs. Employees can also apply for funding through the Training Trust Funds that are in place for each affiliation provided the programs meet the requisite criteria.

By focusing on the knowledge and skills required by our employees, and maintaining its systems for managing these competencies, Terasen Gas will manage the possibility of increased employee turnover in the coming years and continue to meet its goal of Operational Excellence by providing the high level of safety and reliability customers and the public have come to expect.

(iii) Environment, Health and Safety - Goals and Objectives

The EH&S group is made up of the following areas:

- Environmental Affairs, which manages the environmental risks associated with our operations;
- Occupational Health and Safety, which manages employee safety risks and ensures compliance with WorkSafe BC regulations;
- Public Safety Awareness, which educates the public about the properties of natural gas, how to respond to discovering leaks, and how to locate gas lines prior to excavation;
- Emergency Preparedness, which ensures that our emergency response systems comply with applicable legislation and are regularly exercised to maintain employee knowledge;
- Corporate Security, which manages security risks; and
- Business Continuity, which is part of an integrated organizational preparedness program, and a component of the corporate emergency plan.

Generally, EH&S is responsible for the management systems that monitor and support these areas. These systems and programs assist Terasen Gas with ensuring environmental compliance and a safe environment for the public, employees and customers.

(c) Forecast O&M Expenditures by Cost Driver, 2010 - 2011

The 2010 and 2011 HROG forecasted incremental expenditures measured against the prior year are outlined in the two tables below. The tables are followed by a discussion of the increases by cost driver.

Table C-6-31: HROG 2010 O&M Incremental Funding

Department	Labour Inflation and Benefits	Government Policy	Code and Regulations	Demographics	Accounting Changes	Service Enhancements	Total Incremental	Internal Budget Transfers	Total 2010 Incremental O&M
Human Resources and Operational Governance	541	190	852	276	(26)	216	2,049	236	2,285
Total by Cost Driver ($000s)	541	190	852	276	(26)	216	2,049	236	2,285

Table C-6-32: HROG 2011 O&M Incremental Funding

Department	Labour Inflation and Benefits	Government Policy	Code and Regulations	Demographics	Accounting Changes	Service Enhancements	Total Incremental	Internal Budget Transfers	Total 2011 Incremental O&M
Human Resources and Operational Governance	537	30	(110)	63	-	(13)	507	-	507
Total by Cost Driver ($000s)	537	30	(110)	63	-	(13)	507	-	507

(d) Labour Inflation and Benefits

For all departments in HROG, labour inflation and benefits increases by a total of $0.5 million in 2010 and an additional $0.5 million in 2011.

(e) Government Policy

As mentioned on page 350, changes in government policy relating to the environment and GHG reduction are impacting Terasen Gas. To respond to these changes, HROG requires $130 thousand in incremental funding in 2010 for a Sustainability Manager position and $60 thousand for purchase of carbon offsets and funding of assessment efforts. An additional $30 thousand will be required in 2011 to support management of carbon offsets.

(f) Code and Regulations

As indicated in Table C-6-4 and C-6-5, HROG will require incremental funding of $852 thousand in 2010 accompanied by a $110 thousand reduction in 2011 to comply with various code and regulations. Following is a further breakdown of these costs.

Table C-6-33: HROG O&M Increases to Address Code and Regulations

Description of Expenditure	2010	2011
Public Safety Manager	117	
Business Continuity (Manager, Program, Pandemic Planning)	315	(90)
Environmental Program	90	(20)
Security Management Program	10	
Emergency Preparedness Program	115	
Competency Administrator	105	
Web-based Training Modules	100	
Total Code and Regulations ($000s)	852	(110)

(g) Demographics

To support enhanced efforts to effectively manage the demographic risk Terasen Gas faces, HROG requires the following increases in 2010 and 2011.

Table C-6-34: HROG O&M Increases to Address Demographics

Description of Expenditure	2010	2011
Targeted Recruiting and Advertising	50	
Leadership and Program Development	165	(40)
Corporate Events	45	
Instructional Designer		103
Engineer-in-Training	16	
Total Demographics ($000s)	276	63

(h) Accounting Changes

The minor decrease of $26 thousand in 2010 shown in Table C-6-31 above reflects an adjustment for the change in treatment of vehicle lease costs.

(i) Service Enhancements

Outlined in the table below are additional funding required in 2010 and 2011 to review and manage employee benefits and compensation. Other increased expenditures include general administrative expenses and inflationary increases for non-labour expenses.

Table C-6-35: HROG O&M Increases to Manage Workforce

Description of Expenditure	2010	2011
Benefits and Compensation Design and Communication	165	(81)
IBEW Collective Bargaining Consulting	-	40
Other	51	28
Total ($000s)	216	(13)

(j) HROG O&M Summary

In order for HROG to be able to respond appropriately to the Company's changing environment and meet the department's goals and objectives, TGI requires additional funding to support the initiatives outlined above.

(7) FINANCE AND REGULATORY AFFAIRS

The Finance and Regulatory Affairs departments are responsible for providing a range of financial and regulatory services to various departments throughout the Company. These responsibilities must be met in the face of changing financial and accounting standards, as well as changes to legislation and increased regulatory reporting requirements.

In order to successfully meet these requirements and respond to the evolving needs of our customers, regulators and our shareholder, the Finance and Regulatory Affairs departments require the forecasted expenditures for the 2010 and 2011 test years as outlined in this RRA. Terasen Gas believes these forecasted expenditures are reasonable and prudent, and consistent with expenditure levels observed in recent years. Except for required increases to support regulatory requirements resulting from increased stakeholder expectations relating to government energy policy, the forecast O&M expenditures reflect only inflationary increases and accounting treatment changes.

Table C-6-36 below shows the O&M from the 2003 decision as compared to the 2009 projection and the 2010 and 2011 forecast in nominal and real dollars and real O&M per customer. For the period of the RRA, O&M per customer remains below that of 2003.

Table C-6-36: Finance and Regulatory Affairs O&M are lower on a per customer basis than in 2003

	Decision 2003	Projection 2009	Forecast 2010	Forecast 2011
Finance & Regulatory Affairs Nominal O&M ($ millions)	$ 8.6	$ 9.6	$ 9.6	$ 10.0
Finance & Regulatory Affairs Real O&M ($ millions)	$ 9.7	$ 9.6	$ 9.4	$ 9.6
Real O&M per Customer	*$ 13*	*$ 11*	*$ 11*	*$ 11*

(a) Forecast O&M Expenditures, 2010 – 2011

The total forecast O&M for the Terasen Gas Finance and Regulatory Affairs departments in 2010 of $9.6 million is comprised of the following: $7.1 million pertains to compensation and related costs for the 67 full time COPE and M&E equivalent staff. The employee group is a mix of professionals (Chartered Accountants, Certified General Accountants, Certified Management Accountants and MBA graduates) holding management and senior analyst positions, and other non professional staff providing clerical and administrative services. $1.1 million is for BCUC quarterly assessments, $1.2 million relates to audit and filing fees, bank charges, credit rating agency fees and consulting fees, and the remaining $0.2 million is comprised of employee training costs, travel expenses, miscellaneous administrative costs, materials and supplies, and professional membership dues.

(b) Forecast O&M Expenditures by Cost Driver, 2010 - 2011

The primary cost driver for the operating costs of the Finance and Regulatory Affairs departments is labour inflation for the COPE and M&E staff. Labour costs comprise the most significant portion of O&M costs and are subject to contractual and inflationary increases.

The 2010 and 2011 forecasted incremental expenditures measured against the prior year are outlined in the two tables below. The tables are followed by a discussion of the changes by cost driver.

Table C-6-37: Finance and Regulatory Affairs 2010 O&M Incremental Funding

Department	Labour Inflation and Benefits	Customer / Stakeholder Behaviours and Expectations	Accounting Changes	Service Enhancements	Total Incremental	Internal Budget Transfers	Total 2010 Incremental O&M
Finance and Regulatory Affairs	320	300	(199)	(365)	57	-	57
Total by Cost Driver ($000s)	320	300	(199)	(365)	57	-	57

Table C-6-38: Finance and Regulatory Affairs 2011 O&M Incremental Funding

Department	Labour Inflation and Benefits	Customer / Stakeholder Behaviours and Expectations	Accounting Changes	Service Enhancements	Total Incremental	Internal Budget Transfers	Total 2011 Incremental O&M
Finance and Regulatory Affairs	310	-	-	43	353	-	353
Total by Cost Driver ($000s)	310	-	-	43	353	-	353

(c) Labour Inflation and Benefits

For Finance and Regulatory Affairs, labour inflation and benefits increases by a total of $320 thousand in 2010 and an additional $310 thousand in 2011.

(d) Customer / Stakeholder Expectations and Behaviours

In 2010, $300 thousand in funding is required for the addition of two Regulatory Policy Managers to address increasing customer and stakeholder expectations related to government energy policy.

(e) Accounting Changes

In 2010, there is decrease of $400 thousand for the transfer of gas supply accounting to CMAE offset by an increase of $200 thousand for items previously recorded in deferral accounts.

(f) Service Enhancements

BCUC fees are expected to decline by $450 thousand as we move from a formula-based forecast under the PBR Period to an estimate based on historical average. The BCUC fees have been forecast for 2010 using a three year historical average, which for the last number of years has included only three quarters of fees.

Forecasting based on four quarters of fees at the most recent assessment amount would result instead in an increase of approximately $350 thousand in the O&M forecast for Finance and Regulatory Affairs. Terasen Gas has requested a deferral account to capture variances between the forecasted assessment and the actual assessment paid. Should this deferral account be denied, the Company requests an increase in the O&M forecast for Finance and Regulatory Affairs equal to the fourth quarter fees.

For 2011, there is a slight increase due to inflation on expenses and an expected increase in BCUC fees.

(g) Finance and Regulatory Affairs O&M Summary

The Finance and Regulatory Affairs departments require the above levels of forecasted expenditures for the 2010 and 2011 test years. These departments will continue to provide expertise and support in the face of changing financial and regulatory standards and requirements.

(8) PRESIDENT AND CEO

The President and CEO's Office provides overall management and leadership for the Utility. This office ensures that resources are employed efficiently and effectively across all departments to ensure that customers receive value in the rates they pay for the safe, reliable and efficient delivery of natural gas.

Included in the President and CEO Office resources are the President and CEO and Executive Assistant salaries along with their supporting expenses. In addition, the President and CEO Office centralizes certain corporate wide cost items including external legal fees, company insurance premiums, the retiree portions of the pension expense and the OPEB costs, Terasen corporate services fees, industry association fees (i.e. CGA, WEI) and recoveries for Shared Services with its non-regulated businesses, its affiliated utilities TGVI, TGW and also TGI's Core Market Administration Expense.

In order to successfully meet these requirements and respond to the evolving needs of our customers, regulators and our shareholder, the President and CEO Office requires the forecasted expenditures for the 2010 and 2011 test years as outlined in this RRA. Terasen Gas believes these forecasted expenditures are reasonable and prudent, and consistent with expenditure levels observed in recent years. For the period of the RRA, O&M per customer remains below that of 2003.

Table C-6-39: President and CEO Office O&M Declines in 2010 and 2011

	Decision	Projection	Forecast	
	2003	2009	2010	2011
President & CEO Nominal O&M ($ millions)	$ 21.4	$ 17.5	$ 11.3	$ 11.9
President & CEO Real O&M ($ millions)	$ 24.1	$ 17.5	$ 11.1	$ 11.4
Real O&M per Customer	*$ 31*	*$ 21*	*$ 13*	*$ 14*

As discussed in Part III, Section B, Tab 1, costs have declined from that provided for in the 2003 Decision with most of changes occurring primarily as a result of changes in the Shared Services allocation and post employment benefits.

(a) Forecast O&M Expenditures, 2010 - 2011

The total O&M forecast for the President and CEO Office in 2010 of $11.3 million is comprised of the following: $4.4 million for Company insurance premium, $9.0 million for Terasen corporate services fee, $8.5 million credit for Shared Services recoveries, $3.4 million for retiree portions of employee OPEB and pension expenses, $0.6 million for corporate legal expenses, $0.4 million for association fees and $2.0 million for President and CEO Office supporting costs.

The requested 2010 forecast compared to the 2009 projection represents a net decrease of $6.2 million with an increase of $0.6 million in 2011.

(b) Forecast O&M Expenditures by Cost Driver, 2010 - 2011

There are a number of cost drivers for the operating costs of the President and CEO Office. Corporate legal fees are influenced by the level of external legal support required by the different departments in Terasen Gas. The Company's insurance premiums are affected by a number the factors such as the insurance company's insured losses, coverage levels and investment income. Included also is Shared Services between TGI and its affiliates TGVI and TGW and also its parent Terasen with the level of inter-company charge based on the level of activities performed.

The President and CEO will require the forecasted incremental expenditures for 2010 and 2011 which are outlined in the tables below, followed by a discussion by cost driver of the changes.

Table C-6-40: President and CEO 2010 O&M Incremental Funding

Department	Labour Inflation and Benefits	Customer / Stakeholder Behaviours and Expectations	Accounting Changes	Service Enhancements	Total Incremental	Internal Budget Transfers	Total 2010 Incremental O&M
President and CEO	(2,931)	200	(725)	(2,699)	(6,155)	-	(6,155)
Total by Cost Driver ($000s)	(2,931)	200	(725)	(2,699)	(6,155)	-	(6,155)

Table C-6-41: President and CEO 2011 O&M Incremental Funding

Department	Labour Inflation and Benefits	Customer / Stakeholder Behaviours and Expectations	Accounting Changes	Service Enhancements	Total Incremental	Internal Budget Transfers	Total 2011 Incremental O&M
President and CEO	726	-	-	(132)	594	-	594
Total by Cost Driver ($000s)	726	-	-	(132)	594	-	594

(c) Labour Inflation and Benefits

The $2.9 million decrease in 2010 and $0.7 million increase in 2011 are for changes in the retiree portion of pension and OPEB costs.

(d) Customer / Stakeholder Expectations and Behaviours

$0.2 million increase for funding in support of activities for regulated alternative energy services offerings of the utilities.

(e) Accounting Changes

$0.7 million allocation to the Core Market Administration Expense for related back office costs (refer to Part III, Section C, Tab 5 for further discussion).

(f) Service Enhancements

In 2010, the $2.7 million decrease includes a $2.6 million decrease related to increased Shared Services allocation between TGI and TGVI; $0.5 million increase for Terasen corporate services fee (refer to Part III, Section C, Tab 11, Accounting and Other Policies for discussion of Shared and Corporate Services) $0.3 million decrease in insurance expense and a reduction of $0.3 million for supporting costs.

In 2011, the $0.1 million decrease includes $0.4 million decrease related to increased Shared Services allocation between TGI and TGVI; $0.1 million increase for Terasen corporate services fee $0.2 million increase in insurance expense.

(g) President and CEO O&M Summary

The President and CEO Office requires the above levels of forecasted expenditures for the 2010 and 2011 test years to provide overall management and leadership for the Utility.

(h) Terasen Gas O&M Summary

The Company's 2010 and 2011 O&M on a per customer basis is lower than the last Commission decision amount in 2003. The forecasted O&M is lower than the comparable formula-calculated amounts. We take pride in this accomplishment and intend to maintain the efficiencies gained during the PBR Period. The incremental funding requests are required to meet the needs of our customers and stakeholders, and to maintain TGI's profile as an efficient and effective gas utility.

7. Taxes

In carrying out its mandate as a gas service provider, Terasen Gas incurs taxes that are imposed by different government bodies. Terasen Gas manages these expenditures through the tax audit process and various tax planning strategies, as well as ongoing compliance activities. The tax expenses included in this RRA reflect the current substantively enacted tax legislation and have been properly calculated and applied in calculating the Company's revenue requirements.

a) Review History Highlights (2003-2009 Actuals)

Since the beginning of the PBR Period in 2003, there have been reductions in income taxes levied and associated income tax rates, decreases in the rate of Goods and Services Tax ("GST") and implementation of both the ICE Fund levy and the Carbon Tax. The impacts of these changes have appropriately been flowed through to customers through the Annual Review process and associated rates or deferral accounts.

Changes in Income Taxes since 2003 include:

- The Large Corporations Tax ("LCT") which was calculated as a percentage of a corporation's taxable capital employed in Canada, was eliminated effective January 1, 2006;
- The corporate surtax of 1.12 per cent of taxable income was eliminated effective January 1, 2008;
- Federal income tax rates (excluding surtax) have been reduced from 23 per cent in 2003 to 19 per cent in 2009, with further reductions to 18 per cent in 2010 and 16.5 per cent in 2011 reflected in this RRA;
- BC income tax rates have declined from 13.5 per cent in 2003 to 11.0 per cent in 2009, with further reductions to 10.5 per cent in 2010 and 10.0 per cent in 2011 reflected in this RRA.

The combined effect of the elimination of the LCT and corporate surtax, and the declines in federal and BC income tax rates has reduced the tax expense included in revenue requirements by approximately $12 million when comparing 2009 rates to 2003 rates. During the same period, property taxes have increased by approximately $8 million. The annual impacts of these net tax reductions have been returned to customers through the PBR Period.

The ICE levy was implemented September 1, 2007 under the Social Service Tax Act as a temporary tax of 0.4 per cent applicable to purchases of electricity, natural gas and grid propane. The estimated annual cost of the ICE levy to TGI on its own use of energy is approximately $5,500.

The Carbon Tax was introduced in July 2008 and had impacts on the Company's cost structure, reflecting the costs of modifying our billing system to accommodate the tax, as well as increased O&M costs relating to carbon tax on fuel used in vehicles, compressors and line heaters. The 2008 and 2009 impacts of this tax were treated as an exogenous factor, with the impacts deferred and recovered through rates over one to three years. For this RRA, the cost of service impacts of the Carbon Tax have been included in O&M and capital.

The flow through of these taxes to customers during the term of the PBR Period was appropriate, and continues to be the requested treatment for this RRA.

b) Income Tax

Terasen Gas is subject to corporate income taxes imposed by the Federal and BC governments, and as such appropriately includes these costs in calculating the Company's revenue requirements. Current income taxes have been calculated using the flow-through (taxes payable) method, consistent with Commission approved past practice, at the corporate tax rate of 28.5 per cent for 2010 and 26.5 per cent for 2011. The corporate tax rates used in the RRA are based on the Canada Income Tax Act and the BC Income Tax Act substantively enacted legislation.

This information is set out in Appendix F-7: Forecast Assumptions.

As approved by Commission Order No. G-53-94, deferred charges, to the extent they are tax deductible, and deferred credits, to the extent they are taxable, are treated on a net-of-tax basis. Under the net-of-tax method, the gross addition to a deferral account is offset by the tax savings or tax cost (as the case may be) calculated at the prevailing income tax rate for the current year.

c) Property Taxes

Property Taxes are generally the single largest revenue source for municipalities, regional districts, hospital districts and numerous other taxation authorities. Furthermore, approximately 30 per cent of total school tax is collected through property taxes. Shortfalls in economic-based taxes and charges will only create greater pressure and reliance on the property tax to provide the various tax authorities with the necessary funding to balance the budgets. Terasen Gas pays property taxes on its land holdings as well as any improvements, as defined by the Assessment Act.

We have considered the key factors influencing property tax determination and prepared the 2010 and 2011 property tax projections using established practices. We believe that our property tax forecasts accurately and reasonably reflect our future tax liabilities. The following sections describe property tax concepts, our forecasting methodology and projected property tax budget, our management of property tax issues, and justification for the continuation of the Property Tax Variance Deferral Account.

(1) PROPERTY TAX CONCEPTS

The methodology we used to forecast the Terasen Gas 2010 and 2011 property tax liability is consistent with established past practice. Simply put, property tax is a function of corporate revenues earned on gas consumed within municipal boundaries, property assessment values and property class tax rates set by the various taxation authorities.

General taxes collected based on corporate revenue are levied directly by the local government for the provisions of service within the municipality. In BC, utility companies are required to pay 1 per cent (1.25 per cent in the City of Vancouver) of revenues from gas consumed in place of the general portion of taxes for all improvements excluding buildings, which are used solely within a municipality or group of adjoining municipalities for local transmission or distribution. The revenue value used to calculate property tax is based on corporate revenues from two years prior. That is, the component of property tax associated with revenue calculation for the 2010 tax year is based on 2008 actual revenues.

Property assessments reflect the "market value" of each property at the legislated reference date. Valuations are performed largely[184] by BC Assessment and are determined by provisions set out in the Assessment Act. The property assessment value determines how the municipal tax policy will be distributed to individual property owners and the proportionate share of the taxes for a property in relation to other properties within each property class.

The property class determines the tax rate that will be applied to the property based on the "use" of the property as prescribed by legislation. There are currently nine classes of properties defined in the legislation, with the Utility and Major Industry classes typically paying the highest tax rates. Utility tax rates in 2008 were up to 23 times that of residential rates, depending on the municipality. Multiple tax rates apply to an individual tax notice and these may be influenced by one or more of the following four factors:

[184] First Nations are not required to use BC Assessment and some have contracted this service to another party.

1. Municipal tax policy - This value is determined by Council for general municipal taxes and is usually defined as a predetermined percentage of the total tax levy that Council wants to collect from the property class.
2. Provincial tax policy - Provincial tax policy applies to all rural properties and certain tax collectors (i.e. schools, some regional districts, hospital districts) and is based on fixed tax rate ratios.
3. Balancing of the municipal budget - Municipalities are required by legislation to produce balanced budgets and property tax is the mechanism by which balanced budgets are created.
4. Individual property tax collection authorities and their budgets - Tax rates are influenced by individual property tax collection authorities and their budgets.

Property tax is therefore a function of corporate revenue, property assessment and property class tax rate.

(2) PROPERTY TAX FORECASTS

In determining the total Terasen Gas property tax forecasts, each of the three components of property tax was determined as follows.

One key component of the overall property tax is calculated based on revenues. When performing this calculation, it is important to understand that the revenue values used in the calculation are from prior years – not from the year for which the property tax is being determined. For example, when determining the revenue based component of property tax for 2010, the projected 2009 revenue value for Vancouver and the 2008 actual revenue value for the rest of the TGI service territory (excluding Fort Nelson and Squamish) are used. The use of revenue values from different past years introduces a lag and inconsistency effect into this component of the property tax value relative to the overall corporate revenue values.

The element of property tax based on corporate revenue is projected to be as shown in the table below:

Table C-7-1: Revenue based component of property tax will increase in 2010 and then decrease in 2011[185]

($ millions)	2009 Projected	2010 Forecast	2011 Forecast
Property Tax	$15.1	$16.2	$16.1
Annual increase	-	7.3 per cent	-0.6 per cent

[185] Part III, Section C, Tab 13, Financial Schedules 31 & 32

It can be seen from the above table that the annual increase in the property tax based on corporate revenue is forecast to increase by 7.3 per cent in 2010. This increase in the revenue based component of property tax is calculated using projected 2009 revenues for Vancouver and actual 2008 revenues for the rest of the TGI service territory (excluding Fort Nelson and Squamish). Projected 2009 revenues for Vancouver are expected to decrease slightly while actual 2008 revenues increased for the rest of the TGI service territory. The combined effect of these projected and actual revenues is an increase in the revenue based component of property tax for 2010. In comparison, the 2011 property tax is forecast to decrease from 2010. Again, the reason for this property tax reduction is the revenue projections for Vancouver and the rest of the TGI service territory. 2010 revenues for Vancouver are forecast to increase while 2009 revenues for the rest of the TGI service territory are forecast to decrease. The net effect of these forecasts is a reduction in the corresponding property tax component.

To determine the balance of the forecast property tax amounts for 2010 and 2011, we applied the appropriate assessed values and tax rates to Terasen Gas' folio of assets. We identified all the assets for taxation purposes in approximately 1,200 folios and their corresponding assessed values. In aggregate, the total assessed value of all assets for taxation purposes is determined as shown in the following table:

Table C-7-2: Assessed Values used for property tax determination show a marginal increase during 2010 and 2011

($ thousands)	2009 Projected	2010 Forecast	2011 Forecast
Distribution assets	$795.0	$833.9	$850.7
Transmission assets	431.5	435.2	439.4
Gas storage assets	14.1	13.4	13.4
Manufactured Gas Assets	0.4	0.4	0.4
Other	96.4	91.4	93.5
Total	$1,337.4	$1,374.3	$1,397.4

Other than planned build–out of our distribution system, there are no major asset additions that are anticipated to significantly impact the assessed value base of Terasen Gas assets during the 2010 and 2011 period. Terasen Gas has been granted CPCN approval to replace two of its major pipeline crossings in Richmond/Delta under the south arm of the Fraser River. However, this pipeline replacement will not increase the Transmission asset base used for property tax calculations because it is a replacement of an existing asset – not an extension of the pipeline system with a new asset. Only new pipeline system extensions increase the Transmission asset base used for property tax determination.

Subsequently, the individual tax classes were determined for all the assets in each of the folios and the applicable tax rates applied against the assessed values. The individual tax liability associated with each folio is summed to produce the aggregate values shown in the following table;

Table C-7-3: Assessed Value and Rate Class based components of property tax will increase at decreasing rates

($ millions)	2009 Projected	2010 Forecast	2011 Forecast
Property Tax	$31.7	$32.9	$33.9
OGC Fee	$0.1	$0.2	$0.2
Annual increase	7.6 per cent	3.4 per cent	3.0 per cent

The above table shows an increase of 3.4 per cent in 2010 and 3.0 per cent in 2011 property tax based on assessed value and rate class. The 2010 and 2011 increase is driven by annual expansion of the pipeline infrastructure, and higher tax rates expected to offset declines in other municipal revenues sources. In 2011 increases in tax rates are expected to slow somewhat as municipalities adjust their budgets to reflect lower economic activity.

Combining the property taxes based on corporate revenue and that based on assessed value and rate class, the total forecast tax liability is shown in the following table.

Table C-7-4: Total property tax will increase at decreasing rates[186]

Total Value ($ millions)	2009 Projected	2010 Forecast	2011 Forecast
Property Tax	$46.9	$49.1	$50.2
Annual increase	$2.2	$2.2	$1.1
Annual increase	5.0 per cent	4.7 per cent	2.2 per cent

(3) PROPERTY TAX MANAGEMENT

Property taxes are subject to pressure as Municipalities increase their drive to use this tax base to cover increasing shortfalls in their budgets. In response, Terasen Gas has assumed proactive management of property taxes involving more than just assessment reviews and appeals. We take steps to understand Municipal finances and overall tax policies, as well as the political environment. We believe building and

[186] Part III, Section C, Tab 13, Schedules 31 and 32, Line 7, Column (3)

maintaining relationships with the Assessment Authority and those responsible for Tax Policy is critical to mitigate and enhance our ability to understand risks with any degree of certainty. In particular, we are members and active participants in a number of associations in an effort to influence and respond to proposed changes in property tax related matters. The most important of these are:

- The CEPA Property Tax Committee;
- The Canadian Property Tax Association; and
- The Vancouver Board of Trade Local Government and Finance Task Force.

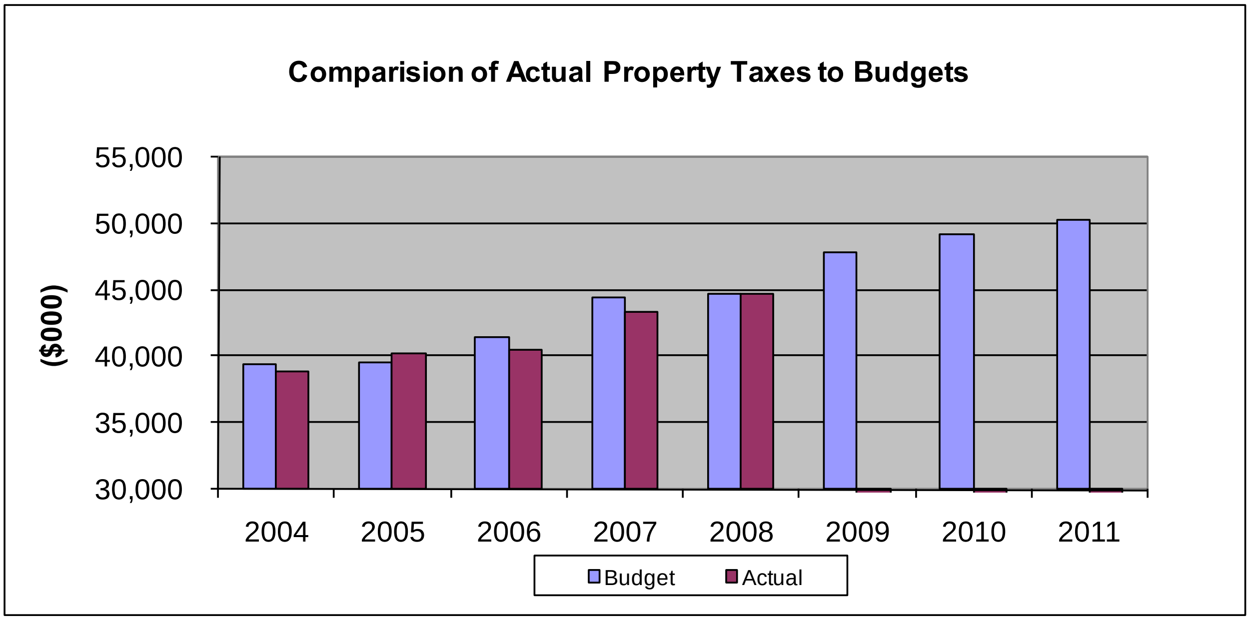
We will continue with our participation in the above associations and pursue proactive management activities because we believe that they provide value to our ability to manage our property tax liability.

(4) PROPERTY TAX DEFERRAL ACCOUNT

Forecasting property tax liabilities carries with it a certain level of risk due to inherent uncertainties associated with the various elements at work (i.e. revenues, government policy, etc.). The uncertainties could result from the timing of property tax related decisions, the magnitude of changes, or political events. Historically, we have experienced the impact of these uncertainties as variances of our actual property taxes against budgeted amounts. Since property taxes are imposed by government, the degree of influence that we can exercise on property tax related matters is limited. Consequently, we believe that the current deferral account mechanism for property tax needs to be continued into 2010 and 2011.

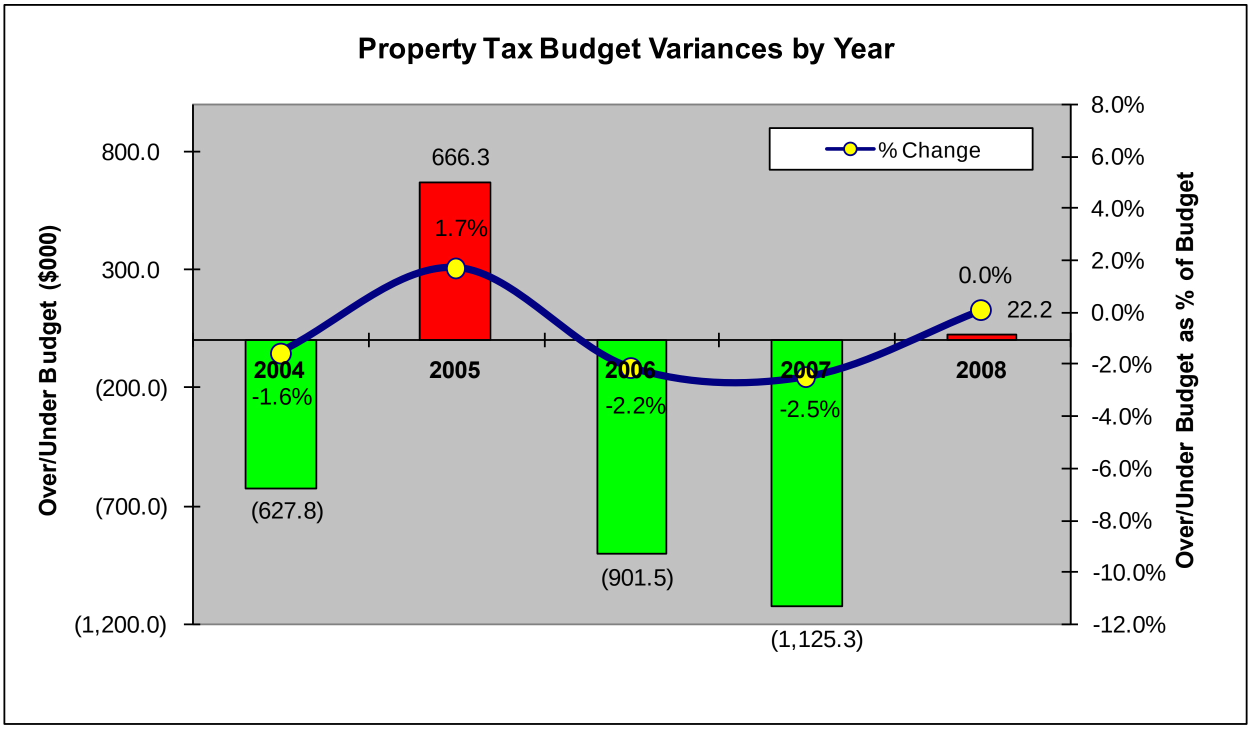
Despite our best efforts to manage property tax to budget, historical information shows that variances against the budget have existed in every year. The following chart shows that our actual tax payments have been close to our annual budget year after year. We were over in some years and under in others and we would expect this over/under pattern to continue into the future.

Figure C-7-1: Actual Property Taxes Have Been Close to Budget Values Year over Year



The following chart shows our annual budget variance as a dollar amount and as a per cent of the total budget. Actual property tax payment has been within a maximum of +/- 2.5 per cent of the total budget representing a maximum variance of approximately $1.1 million

Figure C-7-2: Annual Budget Variances are Random and in the order of Several Hundred Thousand Dollars



The chart above also highlights and confirms two generalities. First, the dollar variance of the property tax budget is in the order of several hundred thousand dollars per year on average. Second, the annual variance can be positive one year and negative in another. Given these two characteristics of the property tax budget variance, it is appropriate that the deferral account treatment for property tax be continued into 2010 and 2011.

d) Carbon Tax

The Carbon Tax was implemented by the Province effective July 1, 2008, and is applicable to the consumption of fossil fuels consumed in the Province. The Carbon Tax represents a cost to the Company on its own consumption of fuel to operate compressors, line heaters, motor vehicles and space heating. The Carbon Tax rate applicable to natural gas effective July 1, 2009 is 74.49 cents per GJ, and will rise to 99.32 cents per GJ on July 1, 2010, and to $1.24 per GJ on July 1, 2011. The impact of this tax in 2008 and 2009 was captured in a deferral account. The estimated cost to the Company in respect of Carbon Tax on own-use fuel is approximately $410 thousand for 2010 and $530 thousand for 2011, and is embedded in O&M and capital in this RRA.

e) BC Social Services Tax ("SST"), Motor Fuel Tax ("MFT") and ICE levy

The Province levies various sales and other taxes, referred to here as provincial sales tax ("PST"), on various goods and services. These taxes include the SST, a tax of 7 per cent on purchases of tangible property and certain services that the Company uses in its operations, the MFT, which applies at a rate of 1.9 cents per 810.32 litres of natural gas used in compressors, and the ICE levy of 0.4 per cent on purchases of energy including electricity and natural gas. Unlike the GST, the SST, MFT and ICE levy are not recoverable and therefore represent a net cost to the Company. The annual cost of SST, MFT and ICE levy borne by the Company can vary widely based on the level of purchases and capital expenditures. The estimated PST cost for 2010 and 2011 is approximately $4.2 million and $4.3 million respectively, excluding PST embedded in gasoline and other vehicle fuels. This cost is embedded in capital and O&M depending on the nature of the property or services acquired.

f) Goods and Services Tax

The GST is a federal commodity tax exigible on goods and services at a rate of 5 per cent. Terasen, as a GST registrant, is entitled to recover virtually all of the GST it pays on its taxable purchases of goods and services. As such, the tax does not represent a net cost to the Company.

g) Tax Issues

(1) RISK OF CHANGES IN TAX LAWS OR ACCEPTED ASSESSING PRACTICES

At any time, the Company can face changes in tax laws or accepted assessing practices in respect of Federal income tax, Provincial income tax, Provincial sales taxes or any other tax that may be imposed. With this RRA, for the 2010 and 2011 forecast period, Terasen Gas is seeking a deferral account to be recovered through rates in 2012 to capture the impact of changes in tax laws or accepted assessing practices, audit reassessments in respect of any tax year, and impacts on taxes of changes in accounting policies, at Federal, Provincial, Municipal or any other level of jurisdiction. In addition, as noted in paragraph (4) below, the income tax deferral account should also capture any changes to the final tax overhead calculation.

(2) TAX BENEFITS RELATING TO PRIOR PERIODS

In 2001 and 2002, after the completion of the Southern Crossing Pipeline, roughly $11 million of costs were incurred for landscaping and restoration of the site. For accounting and regulatory purposes, these costs were capitalized to transmission pipeline. For regulatory tax purposes, the costs were added to Undepreciated Capital Cost ("UCC") as part of Class 1, and customers have been receiving the benefit of the Capital Cost Allowance ("CCA") deductions ever since. To date, customers have received the tax benefits relating to $2.8 million of the total $11 million of costs. For legal entity tax purposes, however, the Company deducted the costs in the years incurred, being 2001 and 2002. The Company's view was that the deduction for tax purposes was appropriate, but there was some uncertainty regarding whether the deductions would be challenged by the CRA. For this reason, and because of the large amount involved, the tax benefits were recorded to the balance sheet until such time as CRA completed its audit of 2002. Ultimately, the CRA audit of 2002 was completed in 2007 and no audit adjustments were proposed.

The Company proposes to make the following adjustments for regulatory purposes, with the view to dealing with the tax benefit that is still on the Company's balance sheet as of December 31, 2008, as well as eliminating the difference in UCC between the Utility and the legal entity. The remaining UCC balance of $8.2 million[187] ($11 million less $2.8 million) is reported as a deduction in the 2009 Timing Difference schedule. The opening 2009 UCC is correspondingly reduced by $8.2 million.

As a result of these adjustments, customers have received the full tax benefit on $2.8 million of costs by way of CCA deductions from 2001 to 2008, and have shared in the remainder of the tax benefits as a result of the 2009 tax deduction. Starting in 2009, the difference between Utility and legal entity UCC in respect of these costs is eliminated.

(3) CHANGES TO CCA RATES

The Federal Budget of 2007 proposed enhanced CCA rates for natural gas distribution pipeline equipment, LNG equipment, buildings, and computer hardware. These CCA rates were approved by the Federal Government in April 2009, but not in time for the Company to recalculate CCA and UCC for purposes of the 2008 Annual Report. As an alternative to reporting the adjustments in the 2008 Annual Report, the Company has adjusted the timing differences on the 2009 Timing Difference schedule by the amount of the increased CCA for 2007 and 2008 of $2.9 million.[188] An offsetting adjustment is made to opening 2009 UCC. The Company has calculated 2009, 2010 and 2011 CCA using the new rates.

(4) CAPITALIZED OVERHEAD STUDY AND IMPACT ON TAXES

As a result of the current overheads capitalized study (discussed in Part III, Section C, Tab 11), the Company has determined that it is appropriate to reduce the tax overhead capitalization rate to 8 per cent of gross O&M from the current rate of 10 per cent of adjusted gross O&M, consistent with

[187] Part III, Section C, Tab 13, Schedule 37, Line 31, Column (2)
[188] Part III, Section C, Tab 13, Schedule 37, Line 27, Column (2)

overheads capitalized for accounting purposes in the RRA. This results in an immediate tax benefit for customers which is reflected in the RRA.

For tax purposes, overhead directly attributable to capital activities is capitalized to UCC; indirect overhead is not. The method of determining overhead to be capitalized for tax purposes is similar to the method of determining capitalized overhead for IFRS purposes, therefore it is reasonable to use the same rate for tax as for accounting purposes. However, the Company is still in the process of assessing the results of the study for tax purposes. The Company proposes that if any further changes are made to the overhead capitalization rate for tax purposes, the impact on CCA will be recorded in the income tax deferral account, and offsetting changes to UCC will be adjusted in 2012.

The reduction to the rate of overhead capitalized for tax purposes is being implemented beginning in 2008. In addition to the lower amount of overhead being capitalized for tax purposes, the Company is adopting a method of allocating overhead to UCC classes that is more consistent with the method used for accounting purposes, which is to allocate primarily to self-constructed assets. Since the tax calculations embedded in the 2008 Annual Report were completed prior to the completion of the capitalized overheads study and therefore use the 10 per cent tax overhead capitalization rate, the Company proposes to make the following adjustment in 2009. The increase in the amount of the tax deduction for 2008, net of the reduction in 2008 CCA, is reported as a $3.3 million[189] timing adjustment in the 2009 Timing Differences schedule. Opening 2009 UCC classes have been adjusted by the difference in CCA and by the change in allocation of overhead. The new lower rate of overheads capitalized for tax purposes is applied in the tax calculation for 2009 and 2010-2011.

(5) FUTURE INCOME TAXES AND IFRS

Effective January 1, 2009, the Company has adopted changes to Canadian GAAP in respect of Section 3465 Income Taxes. This has resulted in the inclusion in rate base of both future income tax liabilities and an equal and offsetting amount for a regulatory future income tax asset, as discussed in Part III, Section C, Tab 11, Accounting and Other Policies. The adoption of IFRS is also discussed in the same section.

For purposes of this RRA, the Company proposes to record in rate base both the Future Income Tax liability compliant with both Canadian GAAP and IFRS, and an offsetting Regulated Future Income Tax asset according to Canadian GAAP.

[189] Part III, Section C, Tab 13, Schedule 37, Line 26, Column (2)

h) Summary of Taxes

Terasen Gas will continue to incur income taxes, property taxes and other taxes that are imposed by different government bodies. Terasen Gas manages these expenditures through the tax audit process and various tax planning strategies, as well as ongoing compliance activities. The tax expenses included in this RRA reflect the current substantively enacted tax legislation and have been properly calculated and applied in calculating the Company's revenue requirements. Any variances from the taxes reflected in this RRA will continue to be captured in a deferral account and flowed through to customer rates.

8. Rate Base

The 2010 and 2011 rate base amounts of $2,536 million and $2,620 million respectively, as determined in Part III, Section C, Tab 13, Schedules 8 and 9 of this RRA, represent the average investment by the Company in utility assets necessary to provide service to our customers, and to meet our obligations under the Utilities Commission Act.

The determination of rate base is a significant step in the calculation of the revenue requirement; it forms the basis for the earned return component of the cost of service. The rate base is comprised of:

- mid-year net plant in-service (gross plant in service, less CIAC, less accumulated depreciation relating to both), adjusted for the timing of completion of major capital projects;
- work-in-progress not attracting allowance for funds used during construction;
- the mid-year balance of unamortized deferred accounts (regulatory assets and liabilities);
- the thirteen-month average of cash working capital and other working capital;
- mid-year future income tax asset and offsetting liability; and
- the LILO benefit arising from LILO agreements with several interior municipalities.

In forecasting the composition and amount of rate base, Terasen Gas has incorporated these underlying principles:

- we must continue to provide the products and services that meet the expectations of our growing customer base;
- we must meet requirements to make improvements related to system integrity and reliability;
- we must invest in systems required to support customer growth;
- we must ensure that the deferred charges we employ are adding value to customers and the shareholder; and
- we must support the government's energy policy and reflect the new energy solutions that the Company has proposed in Part III, Section C, Tab 3, of this RRA.

The following subsections will discuss in detail the various components of rate base, beginning with a discussion of the rate base history throughout the PBR Period.

a) Review History Highlights (2003-2009 Actuals)

Terasen Gas managed rate base prudently and effectively throughout the PBR Period. This is evident by the Company's successful achievement of annual savings relative to the formula-based capital spending allowances in the PBR Agreement[190], while generally continuing to meet service quality indicators and making the necessary investments in plant and equipment to meet the needs of the expanding customer base.

The following table provides a summary of the Terasen Gas normalized actual rate base from 2003-2009:

Table C-8-1: Growth in Terasen Gas Rate Base (2003-2009)[191]

(amounts in $000s)	Normalized						Projection
	2003	2004	2005	2006	2007	2008	2009
Mid Year Net Plant In Service	$ 2,148,301	$ 2,183,500	$ 2,251,298	$ 2,277,975	$ 2,310,133	$ 2,341,921	$ 2,387,253
Adjustment to 13-month average	(6,533)	(7,492)	(5,344)	(1,745)	(2,663)	3,208	(10,554)
Work in progress, no AFUDC	6,565	4,695	14,510	9,927	7,719	7,062	15,627
	2,148,333	2,180,703	2,260,464	2,286,157	2,315,189	2,352,191	2,392,326
Deferred Charges	29,488	23,763	6,274	9,424	(14,754)	(26,223)	(66,709)
Cash Working Capital	(14,434)	(16,452)	(15,410)	(21,611)	(23,624)	(25,044)	(27,183)
Gas In Storage Working Capital	83,461	112,112	151,056	160,586	142,265	164,419	111,734
Other Working Capital	6,699	7,424	8,481	10,469	10,563	12,360	3,967
Other	(4,704)	(1,959)	(2,749)	(2,673)	(3,459)	(3,256)	(1,814)
Utility Rate Base	$ 2,248,843	$ 2,305,591	$ 2,408,116	$ 2,442,352	$ 2,426,180	$ 2,474,447	$ 2,412,321

The mid-year net plant in service is the largest component of rate base, and makes up 86 per cent of the rate base growth from 2004 to 2008. The net plant in service is increased by plant additions related to completed capital projects during the period, and decreased by depreciation expense, representing the consumption of the asset value during the period. Over the PBR Period, regular capital expenditures averaged $80 million per year, contributions averaged $8 million, and capitalized overheads averaged $27 million. The average depreciation rate over the period was 2.7 per cent and the resulting depreciation expense ranged from $80 to $90 million. The Adjustment to 13-month average adjusted for large projects that entered rate base at some point other than the mid-point of the year. Work in Progress showed some variations throughout the years of the PBR depending on what projects were in progress in the year. In 2009, capital spares inventory was reclassified to Work in Progress from Other Working Capital to align with new accounting standards.

The deferral accounts that were in place throughout the PBR Period added value to both the customers and the Company by sharing the risk of variances appropriately between parties and acting as a

[190] See Part III, Section B, Financial Performance section for a discussion of the annual savings achieved
[191] See Appendix I-1 for a copy of Rate Base History

mechanism to dampen rate volatility. The net mid-year balance in deferral accounts has decreased $96 million from 2003 to 2009. The major contributors to this change are an increase in the liability for Other Post Employment Benefits of $24 million, decreases in the margin-related deferrals (CCRA, MCRA and RSAM) of $70 million and earnings sharing credits of $11 million.

The cash working capital throughout the PBR Period was calculated using the net lag days as set out in the 2003 Revenue Requirement application. The trend in the cash working capital, from a rate base reduction of $14 million in 2003 to a reduction of $27 million in 2009, is a result of the increase in operating expenses throughout the period.

The Gas-in-Storage component of working capital was the largest single element of working capital throughout the PBR Period and is influenced by commodity price changes. The gas–in-storage fluctuated from a low of $83.5 million in 2003 to a high of $164.4 million in 2008.

The rate base was calculated during the PBR Period in accordance with the provisions of the PBR Agreement. The rate base for rate setting purposes employed the formula-based approach for annual plant additions and other PBR Settlement provisions pertaining to other rate base components. The actual rate base for each year was determined using accepted methodologies previously approved for Terasen Gas (and other utilities in BC) by the Commission, and formed the basis for the calculation of the actual return on equity. Variations between the actual and approved rate of return on equity were then shared equally between customers and the Company through the earnings sharing mechanism.

b) Rate Base 2010 and 2011

The table below sets out the Company’s rate base for 2010 and 2011, for purposes of determining rates and revenue requirements.

Table C-8-2: Rate Base in 2010 and 2011 is Growing[192]

(amounts in $000s)	**Projection 2009**	**Forecast 2010**	**Forecast 2011**
Mid Year Net Plant In Service	$ 2,387,253	$ 2,438,725	$ 2,481,891
Adjustment to 13-month average	(10,554)	13,537	-
Work in progress, no AFUDC	15,627	15,627	15,627
	2,392,326	2,467,889	2,497,518
Deferred Charges	(66,709)	(27,015)	10,347
Cash Working Capital	(27,183)	(6,778)	(6,133)
Gas In Storage Working Capital	111,734	100,494	114,804
Other Working Capital	3,967	2,945	5,287
Other	(1,814)	(1,648)	(1,482)
Utility Rate Base	$ 2,412,321	$ 2,535,887	$ 2,620,341

Each of the main components of rate base (plant balances, deferral accounts, cash working capital and gas-in-storage working capital) is discussed separately below.

c) Net Plant in Service ("NPIS")

The mid-year NPIS balances of $2,439 million in 2010 and $2,482 million in 2011, Table C-8-2 above, reflects the necessary additions to ensure that Terasen Gas is able to meet the evolving needs of our shareholder and customers. As noted above, the mid-year NPIS is the largest component of rate base and is the sum of the averages of the gross plant in-service (including intangible plant), CIAC and accumulated depreciation.

The 2010 and 2011 NPIS balances reflect the impacts of new accounting standards as discussed in Part III, Section C, Tab 11. Accounting changes that affect the plant balances are:

- $12.0 million of net book value of leased vehicles under capital lease ($26.1 million of original cost less $14.1 million of accumulated depreciation) has been included in the opening 2010 plant, and is being depreciated over the term of the related leases;
- $2.0 million of inspection costs related to transmission pipe has been re-allocated from asset class 465 Mains to sub-class 465 Mains - Inspections, and is being depreciated over the expected time period to the next major inspection;
- The implementation of a change to the treatment of CPCN projects such that they are added into rate base when the asset is available for use, to allow depreciation to commence at that time. This is a departure from the treatment of CPCNs throughout the PBR Period where they were deemed to have an in-service date of January 1 following the year that they went in-

[192] Part III, Section C, Tab 13, Schedules 8 and 9

service consistent with Commission Order No. G-51-03 for the 2004 – 2007 PBR Period, but follows the guidelines contained in the Uniform System of Accounts for Gas Utilities "Gas Plant in Service – this account shall include the investment in property, plant and equipment in service at the date of the balance sheet" and "Gas Plant Under Construction – this account shall include the cost of construction of gas plant not completed or ready for service at the date of the balance sheet".

(1) GROSS PLANT IN-SERVICE ("GPIS")

The ending GPIS balances of $3,449 million in 2010 and $3,536 million in 2011, Part III, Section C, Tab 13 Schedules 8 and 9, Line 3, are made up of opening GPIS plus plant additions, both regular and CPCNs, less retirements. Plant additions are comprised of capital additions plus overheads capitalized, plus AFUDC, and adjusted for opening and closing work-in-progress ("WIP"). Details of capital additions are included in Part III, Section C, Tab 9. Retirements are forecast as a percentage of additions each year. The percentage used is based on a five year historical average for all classes except those subject to Amortization Accounting. For asset classes subject to Amortization Accounting, retirements are forecast based on the year that the asset becomes fully amortized.

Table C-8-3: Terasen Gas Plant Additions 2010 & 2011[193]

Plant Additions ($000's)	2010	2011
Regular Capital Expenditures *	103,965	121,634
Overhead Capitalized	16,767	17,532
AFUDC and WIP Adjustments	4,755	(4,658)
Sub-Total Regular Capital Additions	125,489	134,507
Special Projects & CPCN Additions	27,603	-
Total Plant Additions**	153,090	134,507

* Including Gateway project of $6.8 million in 2010 and $10.4 million in 2011
**Excludes opening adjustment for Capital Vehicle Lease of $26,103

A more detailed reconciliation of capital expenditures to plant additions can be found in Part III, Section C, Tab 13, Schedule 43. The CPCN additions in 2010 relate to the Fraser River South Arm Crossing Upgrade Project of $27.3 million plus an adjustment of $0.3 million relating to the Vancouver Low Pressure Replacement project.

[193] Part III, Section C, Tab 13, Schedule 43

(2) CONTRIBUTIONS IN AID OF CONSTRUCTION

Gross CIAC is composed of opening contributions plus additions and less retirements throughout the year. The year end CIAC amounts of $(184) million in 2010 and $(195) million in 2011 (Part III, Section C, Tab 13, Schedules 8 and 9, Line 9) reflect forecast contributions associated with main extensions, excess service line charges, billable alterations, hazard mitigation work chargeable to customers, and system damage. The forecasted additions are discussed in Part III, Section C, Tab 9. Terasen Gas does not forecast retirements for CIAC, except for software tax savings which are retired based on the year that they become fully amortized.

The opening balance for 2010 includes CIAC related to software tax savings. In this RRA, Terasen Gas is proposing to discontinue the CIAC treatment of tax savings associated with software additions. In addition to being non-compliant with the IFRS standard for PP&E, this treatment no longer has a significant impact on customers' rates due to the uniform magnitude of software investments in each year (forecast software additions are $13.6 million for 2010 and $13.0 million for 2011 per Part III, Section C, Tab 13, Schedules 44 and 46). Terasen Gas proposes to continue to amortize and retire the existing balances associated with software tax savings until a zero net balance is realized.

The CIAC treatment of the tax savings was put in place in the early 1990s when the Company was incurring large expenditures related to new software, to mitigate the uneven effect on customer rates that resulted due to the impact of the two year tax CCA rate (Class 12 at 100 per cent) versus the accounting depreciation period of either five or eight years. This mitigation was accomplished by calculating the tax value of the CCA associated with software (CCA multiplied by the current federal / provincial combined tax rate), accounting for it as a CIAC, and then amortizing it over the same period as the related software. Under this method, there was no CCA calculated on Class 12 or included in the calculation of income tax expense. With this practice being discontinued, the customers will receive the tax expense reduction from the Class 12 assets in the years allowed by the Canada Revenue Agency, instead of being received through reduced amortization over the following 5 or 8 years.

(3) ACCUMULATED DEPRECIATION

The rate base of Terasen Gas includes both the accumulated depreciation of plant in service, and accumulated amortization of CIAC. Both are increased through depreciation and amortization expense, and decreased through retirements.

There are three accounting related changes that have been incorporated into 2010 accumulated depreciation. Two of the changes relate to gains and losses on disposal of assets. One change relates to the commencement of depreciation.

(a) Existing Gains for General Plant Accounts

$7.6 million has been transferred from accumulated depreciation to the IFRS transitional deferral account as an opening balance adjustment for 2010. This amount represents the transfer of the unrecognized accumulated gains of prior years from those general plant balances where Terasen Gas will be adopting a whole life depreciation method for IFRS compliance. The whole life method bases the depreciation rate on the original cost less future net salvage over the estimated average service life of the plant, and does not consider the level of accumulated depreciation when setting the depreciation rate. See Part III, Section C, Tab 11, for a listing of the general plant classes this method is applicable to. These amounts need to be removed from the accumulated depreciation balances to allow for the proper calculation of whole life rates in 2010 and 2011. The transfer of the balances has no impact on the revenue requirements for the forecast years; the future disposition of the IFRS transitional deferral account will be determined at a future date.

(b) Gains and Losses on Asset Disposal

In the past and consistent with accepted regulatory group depreciation methodologies, the accumulated depreciation account has held the gains and losses on disposal of assets. IFRS now requires that gains and losses on disposal of assets must be recognized in income. As discussed under Deferral Accounts below, Terasen Gas is proposing to instead include these asset gains and losses in a deferral account, to preserve the effect of the regulatory treatment. Terasen Gas has not forecast any gains or losses on asset disposal for 2010 or 2011.

(4) COMMENCEMENT OF DEPRECIATION

Prior to 2010, Terasen Gas commenced depreciating assets on January 1 of the year following when the assets went into service. To achieve compliance with IFRS requirements, for 2010 and forward, depreciation is calculated at the time the asset is included in plant and available for use. For purposes of forecasting depreciation expense, it has been assumed that assets related to new plant additions are available for use half way through the year, except for major projects for which the depreciation has been adjusted to reflect the timing of when they are forecast to be available for use.

In addition, the accumulated depreciation balances reflect depreciation expense calculated using the depreciation rates as recommended by the updated Depreciation Study (see Part III, Section C, Tab 11 for further discussion of the depreciation study). The depreciation rate of 3.19 per cent for Distribution CIAC has been determined as the average depreciation rate for asset classes 473 Services, 474/478 Meters, and 475 Mains. The depreciation rate of 2.18 per cent for Transmission CIAC has been determined as the average depreciation rate for asset classes 465 Pipe, 466 Compressor Equipment, and 467 Measuring, Regulating and Telemetry Equipment.

d) 13-Month Adjustment

For large capital projects, the rate base is adjusted to reflect the timing of when these projects go into rate base. The 13-Month Adjustment in 2010 relates to the Fraser River South Arm Crossing Upgrade Project, which is included in rate base January 1, 2010. There are no large projects being added to rate base in 2011; consequently there is no 13-Month Adjustment in 2011.

e) Work in Progress included in Rate Base

Consistent with past practice, Work in Progress included in Rate Base represents construction work in progress for projects that are shorter than three months in duration and less than $50 thousand. Projects over this threshold attract AFUDC, and are not included in rate base until they are available for use, at which time AFUDC is no longer charged to the capital project. The Work in Progress (not attracting AFUDC) included in Rate Base has been forecast at the ending 2008 balance for both 2010 and 2011.

f) Deferral Accounts (Regulatory Assets and Liabilities)

Although IFRS do not currently have a standard that explicitly allows the recognition of rate regulated deferral accounts, an Exposure Draft on Rate-regulated Activities is expected to be issued in July 2009, which if issued as a standard would allow recognition of deferral accounts under certain circumstances.[194] Despite some uncertainty around the recognition of regulatory deferral accounts for financial statement purposes, Terasen Gas is continuing to employ deferral accounts in this RRA. If the final Rate-regulated Activities standard does allow the recognition of these deferral accounts under IFRS, then the accounts discussed below would continue to serve the same purposes as in the past. If these deferral accounts are not recognized under IFRS, then these accounts would also serve to hold the differences between the regulatory accounts and the financial records of the Company.

Terasen Gas has considered the following factors with respect to continuing existing deferral accounts and seeking deferral account treatment in different matters:

- Maintain those accounts that continue to provide benefits as appropriate to customers and our Company in 2010 and 2011;
- Create new mechanisms to address uncontrollable matters appropriately; and

[194] See Appendix H-1 for IFRS Summary

- Create new mechanisms associated with the new business models the Company is proposing in order to offer integrated energy solutions to customers and communities.

As per the Decision attached to Commission Order No. G-7-03 in referencing the approval of individual deferral accounts, the Commission wrote: "The Commission believes that its Orders supporting these requests continue in force until a change is approved by the Commission. For greater certainty, the Commission approves the continuation of amortization rates as previously ordered." Consistent with that Decision, Terasen Gas has continued to employ deferral accounts previously approved by the Commission. The Company is also discontinuing the use of certain deferral accounts that are no longer required. The Company is seeking approval with this Application to add new deferral accounts that result from circumstances that did not exist during the term of the PBR Period.

Table C-8-4: Deferral Balances included in Rate Base benefit Customers[195]

Mid-Year Deferral Balances ($ thousands)	Section Ref	Projection 2009	Forecast 2010	Forecast 2011
Margin Related				
Commodity Cost Reconciliation Account (CCRA)	1(a)	(22,954)	(11,371)	-
Midstream Cost Reconciliation Account (MCRA)	1(b)	6,417	18,212	-
Revenue Stabilization Adjustment Mechanism (RSAM)	1(c)	(10,541)	(10,971)	(6,583)
Interest on CCRA/MCRA/RSAM	1(d)	(2,543)	(1,371)	51
Revelstoke Propane Cost Deferral Account	1(e)	(258)	(19)	-
SCP Mitigation Revenues Variance Account	1(f)	(5,927)	(4,795)	(3,065)
Energy Policy Related				
Energy Efficiency & Conservation (EEC)	2(a)	3,788	15,104	33,460
NGV Conversion Grants	2(b)	131	143	217
Non-Controllable Items				
Property Tax Deferral	3(a)	(738)	(545)	(254)
Insurance Variance	3(b)	(473)	(343)	-
Pension & OPEB Variance	3(c)	(240)	(343)	-
BCUC Levies Variance	3(d)	(279)	(131)	-
Interest Variance	3(e)	(1,743)	(1,708)	(1,043)
Olympics Security Costs Deferral	3(g)	261	1,471	2,016
IFRS Conversion Costs	3(h)	249	494	535
Cost of Current Applications				
2009 ROE & Cost of Capital Application	4	221	397	309
2010-2011 Revenue Requirement Application	4	425	596	199
CCE CPCN	4	95	170	132
Other				
IFRS Transitional Deferral	5(a)	-	(7,603)	26,807
Pension & OPEB Funding	5(c)	(30,598)	(22,314)	(46,691)
Residual Deferred Charges				
SCP Tax Reassessment	6(b)	7,351	7,408	7,408
Deferred Service Line Installation Fee	6(c)	1,443	-	-
Earnings Sharing Mechanism	6(d)	(11,501)	(9,713)	(3,151)
Other	6(a)	706	217	-
Total		**(66,709)**	**(27,015)**	**10,347**

(1) MARGIN RELATED DEFERRALS

Margin related deferrals decrease the volatility in rates caused both by fluctuations in gas prices and by the significant impacts of weather and other factors on use rates.

195 Part III, Section C, Tab 13, Schedules 54 ,55 and 76

Deferring the cost and delivery margin impacts arising from unforecast variations in these factors and recovering them from, or refunding them to customers over a longer period of time is an effective method of reducing rate volatility.

Terasen Gas has included the forecasted balances for the following previously-approved Margin Related Deferrals in rate base.

(a) Commodity Cost Reconciliation Account

The CCRA, approved by Commission Order No. G-25-04, accumulates the costs incurred by Terasen Gas to purchase its portion of the baseload gas requirements, and the revenue collected by Terasen Gas through gas commodity rates. Commodity price-related variances are collected in the CCRA and are taken into account when determining future commodity rate changes. Commodity rates are reviewed every quarter, and typically reset when the commodity recovery to cost ratio, on a 12-month prospective basis, falls outside the 0.95 to 1.05 threshold. Generally, when commodity rates are reset, the new rate is designed to recover or refund, over the next 12 months, any existing CCRA account balance, along with any increase of decrease in commodity costs forecast to occur over the next 12-month period. Any variances that arise in 2010 and 2011 between the forecasted CCRA balances and the actual amounts realized will be subject to deferred interest treatment.

(b) Midstream Cost Reconciliation Account

The MCRA, approved by Commission Order No. G-25-04, captures all the costs the Company incurs in performing the midstream function and the revenue collected by Terasen Gas through midstream rates. In its midstream role, the Company uses its portfolio of pipeline and storage resources, spot and peaking commodity purchases, and sales and mitigation activities as approved in the Annual Contracting Plan to manage load variability. The MCRA accumulates any resulting cost variances, including any volume-related variances due to differences between the forecast and actual consumption. The resulting variances are taken into account when determining future midstream-related rates. Midstream rates are reviewed on a quarterly basis, and, under normal circumstances, midstream rates are adjusted on an annual basis with a January 1 effective date. Generally, when midstream rates are reset for the upcoming calendar year, the new rate is designed to recover or refund, over the next 12 months, any existing MCRA account balance, along with increase or decrease in midstream costs forecast to occur over the next 12-month period. Any variances that arise in 2010 and 2011 between the forecasted MCRA balances and the actual amounts realized will be subject to deferred interest treatment.

(c) Revenue Stabilization Adjustment Mechanism

The RSAM, originally approved by Commission Order No. G-59-94, is a mechanism that stabilizes the Company's delivery margin revenue from the Residential and Commercial customer classes (Rates 1, 1U, 1X, 2, 2U, 2X, 3, 3U, 3X and 23). The RSAM enables the Company to record delivery margin revenue for these customer classes based on the forecast use per customer for each rate class that was used in establishing rates. If weather or other factors result in the customer use varying from forecast, an entry is made to the RSAM account that adjusts revenue collected from customer rates from actual use to what customers would have paid based on forecast use. If actual use is less than forecast, the RSAM deferral account is charged for the variance in use times the delivery rate and the RSAM revenue is credited. Conversely, if actual use is greater than forecast, the RSAM deferral account is credited and the RSAM revenue is decreased. RSAM account balances will continue to be recovered from or returned to customers through Delivery Rate Rider 5 over a three year period. Any variances that arise in 2010 and 2011 between the forecasted RSAM balances and the actual amounts realized will be subject to deferred interest treatment. The 2010 account balance variances and the associated deferred interest will be returned to or recovered from customers through an adjustment to Rate Rider 5 from 2011 to 2013; the 2011 account balance variances and the associated deferred interest will be returned to or recovered from customers through an adjustment to Rate Rider 5 from 2012 to 2014.

(d) Interest on CCRA, MCRA and RSAM

Consistent with past practice, and as approved by Commission Order No. G-7-03, variances from the forecast CCRA, MCRA, and RSAM balances attract interest at the Company's short-term borrowing rate. The booking of interest on variances reduces the likelihood of large carrying cost benefits or losses accruing to either the Company or to customers. Balances in these accounts and variances from the forecast amounts will be recovered from or returned to customers using the same methodology as outlined above for the associated CCRA, MCRA and RSAM accounts.

(e) Revelstoke Propane Cost Deferral Account

The Revelstoke Propane Cost Deferral Account, approved by BCUC Order No. G-72-90, captures the difference between the actual cost of propane and the amount recovered in rates, based on the approved reference price of propane. The propane reference price is reviewed on a quarterly basis, and typically reset when the propane recovery to cost ratio, on a 12-month prospective basis, falls outside the 0.95 to 1.05 threshold. In general, when the propane reference price is reset, the new reference price is designed to recover or refund, over the next 12 months, any existing deferral account balance, along with any under or over recovery of propane costs forecast to occur over the next 12-month period.

(f) SCP Mitigation Revenues Variance Account

The SCP Mitigation Revenues Variance Account, approved by Commission Orders No. G-124-00, No. G-123-01 and No. G-7-03, relates to the use of SCP transportation capacity that has not been utilized by the firm transportation agreement customers and is sold to others, and the third party back-haul movements from Kingsvale to Yahk which relate to transportation service in a West to East direction through the system. These revenue streams are highly uncertain and cannot be locked-in due to the fact they are contingent on the availability of unused firm shipper capacity and the unpredictability of the price differentials at the time the capacity is available. For this RRA, Terasen Gas has forecast an annual amount of $2.4 million in revenues (Part III, Section C, Tab 4, Table C-4-11). Any variation from this $2.4 million in actual revenues received will be captured in the SCP Mitigation Revenues Variance Account. There have historically been two separate deferral accounts capturing the mitigation revenues (SCP Net Mitigation Revenue and SCP West to East Transmission Revenue); the Company is proposing to combine these two accounts into one, and to amortize the balance in this account as at December 31, 2011 over a three year period beginning in 2012.

(2) ENERGY POLICY RELATED DEFERRALS

Energy Policy Related Deferrals assist in capturing costs incurred by Terasen Gas in association with Provincial and Federal energy policies. Deferring and amortizing these costs matches the costs of the programs with the period of time that the benefits are expected to be realized by customers. Terasen Gas has included the forecasted balances for the previously-approved Energy Efficiency and Conservation deferral and the Natural Gas Vehicle Conversion Grant deferral accounts in rate base, as per the Commission's decision in our EEC Application. Consistent financial treatment is sought for incremental EEC expenditures. We also request Commission approval for the establishment of the New Energy Solutions deferral account as described below.

(a) Energy Efficiency and Conservation

These costs will be incurred by Terasen Gas subject to the guidelines of its EEC Application, which was approved by Commission Order No. G-36-09. These costs relate to incentive programs for residential and commercial customers, conservation education and outreach, and other energy efficiency programs. The Commission approved in the EEC Application decision the use of a deferral account for approved expenditures in the 2008-2010 period. It also approved the inclusion of the forecast deferral account balances in rate base on a net-of-tax basis and to amortize these balances in rates over a ten year period.

As discussed in Part III, Section C, Tab 3, we are seeking increases in EEC funding for 2010 for interruptible Industrial customer programs, Innovative Technologies programs, and to provide funding for all EEC programs for 2011. In total, deferral expenditures for 2010 are $25.9 million, consisting of $23.1 million already approved by Commission Order No. G-36-09 plus an additional $2.8 million of new funding. Deferral expenditures for 2011 are $29.6 million, consisting of $23.1 million for programs and amounts consistent with Commission Order No. G-36-09, plus an additional $6.5 million in new programs. Details of these amounts can be found in Part III, Section C, Tab 3, Table C-3-2. Consistent with the EEC Decision, the Company will include the forecast deferral account balances in rate base on a net-of-tax basis for 2010 and 2011, and amortize these balances in rates over a ten year period. Any variances between the forecast level of expenditures and actual expenditure levels will be amortized in rates beginning in 2012.

(b) NGV Conversion Grants

Terasen Gas has continued to use the NGV Conversion grant program, as approved by Commission Order No. G-98-99. The Company records the actual amount of grants in the NGV Conversion Grants deferral account, and amortizes them in rates over five years. Any variances between the forecast level of expenditures and actual expenditure levels will be amortized in rates beginning in 2012.

(c) New Energy Solutions

As discussed in Part III, Section C, Tab 3, we are seeking approval to recover in a deferral account the revenues, ongoing O&M and capital-related costs for investment in energy solutions in NGV and alternative energy. Because the costs and revenues will vary greatly depending on the number and timing of successful projects, we have not included any additions into this account for 2010 or 2011, and instead propose the deferral account would be a non-rate base account attracting AFUDC. The resulting balance in this account at the end of 2011 will be included in rate base, and future treatment of the account will be applied for in the revenue requirement application for that year.

(3) NON-CONTROLLABLE ITEM DEFERRALS

Non-controllable Item Deferrals are employed for items which are either outside of the Company's control or where the Company has limited ability to influence the costs and they are costs properly borne by customers. Deferring the variances from the forecast level of costs for these activities reduces the exposure for both Terasen Gas and ratepayers due to significant variances in these amounts, and serves to avoid windfall gains or losses to the Company or to customers. Terasen Gas has included the forecasted balances for the following previously-approved Non-controllable Item deferral accounts in rate base.

(a) Property Tax Variance

The Company has limited ability to influence property taxes, which are imposed by municipalities and other levels of government, and are influenced by assessed property values, mill rates, and shortfalls in other areas within a municipal boundary. A significant portion of property taxes is tied to the amount of revenues collected within municipalities ("1 per cent in lieu" tax), and fluctuates with commodity-related variations in revenues. Further information on property tax and related risks is found in Part III, Section C, Tab 7, Taxes. The Company will continue to defer the variance between actual and forecast property taxes, as most recently approved by Commission Order No. G–51-03, and amortize it in rates over a three year period. Any variances from amounts forecast will be amortized in rates in 2012.

(b) Insurance Variance

Insurance costs may differ significantly from the levels forecast, due to changes in economic factors outside of the Company's control. Examples of recent events that have had a significant impact on insurance premiums are the extent and severity of hurricane activity in the Caribbean and Gulf of Mexico, California wildfires, and the global financial crisis. The impact of this type of event cannot be incorporated in insurance premium forecasts. A deferral account for these variances was approved by Commission Order No. G-51-03 with amortization over a one year period. The Company has continued with this account and treatment. Any variances from amounts forecast will be amortized in rates in 2012.

(c) Pension and Other Post Employment Benefits Variance

A deferral account for pension variances was approved by Commission Order No. G-51-03, with amortization in the following year. Volatility in the accounting expense related to both pension and OPEB costs is likely to increase with the implementation of IFRS, as market-driven changes are reflected immediately in income. It is therefore critical that variations from forecast are captured in a deferral account, both to avoid large fluctuations in recovered amounts from year to year, and to allow for the uncontrollable nature of these costs. Terasen Gas will continue this deferral account treatment for pensions, and proposes to extend this to other post employment benefit costs, with amortization over a three year period. Any variances from amounts forecast will be amortized in rates in 2012.

(d) BCUC Levies Variance

Variations in BCUC levies from those recovered in rates were approved for deferral account treatment by Commission Order No. G-112-04, with amortization in the following year. The account recognizes that the amount of funding that the Commission requires is dependent on a number of factors that are outside the control of Terasen Gas, and is primarily driven by the number and complexity of applications in any given year. Any variances from amounts forecast will be amortized in rates in 2012.

(e) Interest Variance

Interest rates have historically been difficult to predict; this is particularly so with the current economy. To avoid potential gains or losses on forecasting of interest rates, the Company proposes to continue the Interest Variance deferral account. This account captures the impact on interest expense of interest rates variances (including interest rate variances on customer security deposits) and variances in the timing of long-term debt issues, as compared to forecast. This deferral was previously approved by Commission Order No. G-7-03, amortized in rates over three years. The Company will continue this treatment. Any variances from amounts forecast will be accumulated and amortized in rates in 2012.

As discussed on page 442, Gas in Storage and Other Working Capital, Terasen Gas proposes to create a separate rate base deferral account to capture interest at the unfunded debt rate on variations between the forecasted balances in the gas in storage account that are included in rate base, and the actual balances in the account through the year. The amounts will be amortized in rates in 2012.

(f) Tax Variance

At any time, the Company can face changes in tax laws or accepted assessing practices in respect of Federal income tax, Provincial income tax, Provincial sales taxes or any other tax that may be imposed. With this RRA, for the 2010 and 2011 forecast period, Terasen Gas is seeking a deferral account to be amortized in rates in 2012 to capture the impact of changes in tax laws or accepted assessing practices, audit reassessments in respect of any tax year, and impacts on taxes of changes in accounting policies at Federal, Provincial, Municipal or any other level of jurisdiction. In addition, as noted in Part III, Section C, Tab 7, the income tax deferral account would also capture any changes to the final overhead rate and associated calculation that is adopted for income tax calculation purposes.

(g) Olympic Security Costs

The security costs related to the 2010 Olympic and Paralympic games, approved for deferral treatment by Commission Order No. G-191-08, will be amortized over three years commencing in 2011. Any variances from amounts forecast will be amortized in rates in 2012.

(h) IFRS Conversion Costs

The costs associated with the conversion to IFRS, approved for deferral treatment by Commission Order No. G-191-08, will be amortized over three years commencing in 2011. Any variances from amounts forecast will be amortized in rates in 2012.

(4) DEFERRED COSTS OF CURRENT APPLICATIONS

Terasen Gas will incur costs in 2009 to prepare applications for the Customer Care Enhancement CPCN, for the ROE and Cost of Capital Application, and for the current RRA. Costs incurred consist of legal fees, costs for expert witnesses and consultants, costs related to independent validation of study results, intervenor and participant funding costs, Commission costs, required public notifications, and miscellaneous facilities, stationery and supplies costs. Terasen Gas is proposing to allocate 10 per cent of these costs to Terasen Gas (Vancouver Island) Inc., based on number of customers. Consistent with past practice, Terasen Gas proposes to defer these costs in 2009 for recovery over 2010 and 2011 for Revenue Requirement Application costs, and over five years beginning in 2010 for ROE/Cost of Capital and Customer Care Enhancement application costs. Any variances between the forecasted account balances and the actual incurred costs will be amortization in rates in 2012.

(5) OTHER DEFERRALS

(a) IFRS Transitional Deferral

A number of assumptions have been made in the preparation of this Application about final IFRS and their impacts on Terasen Gas. The Company proposes a deferral account to capture:

- Retained earnings adjustments required on transition to IFRS. At present, the only known retained earnings adjustment is to recognize all cumulative actuarial gains and losses on pension plans in the amount of $57.7 million (see further discussion in Part III, Section C, Tab 11).
- The 2011 impact of a one-time adjustment of $11.2 million to pension expense under IFRS to recognize a market valuation allowance(see further discussion in Part III, Section C, Tab 11).
- The one-time transfer of the existing gain balance of $7.6 million from General Plant as part of the conversion in preparation for IFRS.
- The impact of any difference between the depreciation rates or methodology recommended in this Application and the rates eventually required to comply with IFRS.
- The impact of any difference between the overhead capitalization rate or methodology recommended in this Application and the rate or methodology required to comply with IFRS.

- The rate impact of any other standard where the result of the particular IFRS is varied from what is assumed in the preparation of this Application – see Table C-8-5 below for those standards that are expected to change before adoption.

Terasen Gas requests Commission approval to include the IFRS Transitional Deferral in rate base, with disposition of the actual balances to be determined at a future date.

The following table indicates which standards have changes anticipated before conversion to IFRS in 2011:

Table C-8-5: Standards with Anticipated Changes before Conversion to IFRS

	Changes Likely To Be Available Before the End of 2009	Changes Likely To Be Available In 2010 - 2011
1	Group Cash-settled Share-based Payment Transactions (Q2 2009)	Financial Instruments (2010)
2	Joint Ventures (Q3 2009)	Fair Value Measurement Guidance (2010)
3	First-time Adoption of IFRS (Q3 2009)	Income Taxes (2010)
4	Related Party Disclosures (Q3 2009)	Rate-regulated Activities (2010)
5	Discontinued Operations (Q4 2009)	Earnings per Share (2010)
6	Consolidation (Q4 2009)	Management Commentary (2010)
7	Emissions Trading Schemes (Q4 2009)	Derecognition of Financial Assets (2010)
8	Liabilities (Q4 2009)	Financial Statement Presentation (2011)
9	Financial Instruments - Characteristics of Equity (Q4 2009)	Insurance Contracts (2010)
10		Leases (2011)
11		Post-employment Benefits (2011)
12		Revenue Recognition (2011)

(b) Gains and Losses on Asset Disposition

IFRS require that gains and losses on disposal of assets be recognized in the income statement. Terasen Gas proposes to defer the amount of these gains and losses during the term of this Application, for recovery in future years. This will have the same result as current practice, which is to record gains and losses in accumulated depreciation, and recover through future depreciation rates. The Company does not forecast gains or losses on asset disposals, however we request Commission approval for any gains and losses incurred during 2010 and 2011 to be included in this rate base deferral account. The amortization period for these amounts will be determined in the next RRA.

(c) Pension and Other Post Employment Benefit Funding (OPEB) Differences

Terasen Gas records the difference between amounts funded by ratepayers for OPEB and amounts actually paid out by the Company in a deferral account, on a net of tax basis. This treatment was approved by Commission Order No. G-135-99.

Terasen Gas accepts that amounts funded by ratepayers through both pension and OPEBs through the collection of actuarially-determined expense amounts in rates, but not yet paid out by the Company, should be included in deferrals and be a component of rate base. It also follows that any amounts funded by the Company in advance of being funded by ratepayers would also be included in a rate base deferral.

In the past, the OPEB deferral account has been treated on a net-of-tax basis instead of adjusting for the difference between the OPEB expense and OPEB payments as a timing difference in the calculation of income taxes, as is done for pension expense. Terasen Gas is proposing to discontinue the net-of-tax treatment for the OPEB funding differences effective 2010, and instead add back the OPEB expense as well as the pension expense and deduct the payments in the calculation of income tax expense. This will also achieve consistency in treatment between Terasen Gas and Terasen Gas (Vancouver Island) Inc.

In summary, Terasen Gas has included the pension and OPEB funding differences in rate base. The existing net-of-tax balance of the OPEB will be carried forward as a starting point for 2010, but future additions to both accounts will be on a pre-tax basis with the timing of tax deductions recognized in the calculation of income tax expense. Terasen Gas requests approval to expand the OPEB funding deferral account to also include pension funding differences, and include the additions to this account in rate base on a pre-tax basis.

(d) Customer Care Enhancement Costs

In the CCE CPCN Application filed on June 2, 2009, Terasen Gas requested approval for the creation of a non-rate base deferral account attracting allowance for funds used during construction (AFUDC), and approval to record all incremental costs associated with the Project that are incurred prior to the Project implementation date of January 1, 2012, for the purposes of permitting cost recovery. With this RRA, we are also requesting that the deferral account capture any amounts related to the timing of when the CCE project is available for use and when it is actually added into rate base. If the project is available for use prior to January 1, 2012, for the intervening months, depreciation expense and CCA impacts will be recorded, and AFUDC treatment will continue but only on the monthly depreciated net book value of the project.

(6) RESIDUAL DEFERRALS

(a) Accounts Amortized in 2010

A number of deferral accounts were created for a specific purpose during the term of the last PBR Period, and have an opening balance in 2010 which the Company proposes to amortize in rates in 2010. Terasen Gas will be discontinuing the use of these deferral accounts after the amounts are amortized in 2010.

Four deferral accounts will have no further additions after December 31, 2009. The Company proposes to amortize the remaining balance in rates in 2010:

- Corporate Capital Tax Assessments balance of $3 thousand credit
- Carbon Tax Implementation balance of $95 thousand credit
- TGS Amalgamation balance of $132 thousand
- TGS O&M Variance balance of $352 thousand

Two deferral accounts have a projected balance at December 31, 2009 which will be amortized in rates in 2010. Any future costs related to these two items have been forecasted in the Company's O&M for the two forecast years:

- Carbon Tax Cost of Service balance of $44 thousand credit
- OSC Certification Compliance Costs balance of $91 thousand

Terasen Gas currently has a deferral account for Rate 14/14A Bad Debt, established by Commission Order No. G-64-04. In its Application regarding Rate Schedule 14A for the 2009/2010 gas contract year, Terasen Gas proposed to eliminate the existing Bad Debt Allowance Deferral account. In its decision in Order No. G-44-09, the Commission ordered that the disposition of the remaining balance in the Bad Debt Allowance Deferral account will be dealt with in the review of revenue requirements for 2010. Accordingly Terasen Gas requests as part of this RRA that the forecast December 31, 2009 balance in the deferral account of $140 thousand credit be closed into the existing Allowance for Doubtful Accounts.

Both accounts are included in rate base, so there will be minimal impact to rates resulting from this change.

(b) Southern Crossing Pipeline Reassessment

Terasen Gas continues to hold an amount for reassessment of provincial sales tax related to the SCP project in a rate base deferral account, as approved by Commission Orders No. G-160-06 and G-153-07. The Company is appealing the reassessment, but has remitted a net payment of $7.1 million to prevent further accrual of interest, which will be refundable with interest in the event Terasen Gas is successful on appeal. Terasen Gas will continue to collect in a rate base deferral account, the net payment along with costs of appeal, currently estimated at $0.3 million. When the appeal is resolved, the Company will seek a Commission order with respect to the disposition of the deferral account.

(c) LILO Reassessment

On June 10, 2009, Terasen Gas was notified of a potential tax reassessment related to the LILO agreements first entered into by the Company in 2001. The first of these agreements was made with the City of Kelowna, with subsequent LILO agreements with the municipalities of Prince George, Vernon, Nelson and Creston. The Company understands the CRA has ruled that a portion of the lease payments made by Terasen Gas represent consideration for the cancellation of the municipalities' purchase options and should be treated as such. If this treatment is sustained, it appears that the tax deduction of a portion of the lease payments will be extended to a longer period, as opposed to being deductible as incurred.

Since 2001, customers have benefited from the LILO arrangements, both through their share of the financial benefits, and by continuing to have natural gas distribution service within the affected municipalities under the jurisdiction of the BCUC.

The Company is not able to assess the full tax impact until the CRA ruling is reviewed. Due to the significant uncertainty around any potential tax liability, Terasen Gas believes it is appropriate that a non-rate base deferral account attracting AFUDC be created, to record any resulting payments and associated legal costs, for disposition pursuant to a future direction from the Commission.

(d) Deferred Service Line Installation Fee

Subsequent to the System Extension and Customer Connection Policies Review in late 2007, Commission Order No. G-153-07 approved a deferral account to capture the Service Line Installation Fee which was no longer collected from customers beginning in 2008. Terasen Gas requests Commission approval to net the $1.443 million balance in this deferral account against the Distribution Contributions in Aid of Construction as of January 1, 2010.

(e) Earnings Sharing Mechanism

Under the terms of the current PBR Agreement, Terasen Gas is to share pre-tax earnings variances between the authorized level of earnings as determined annually under the settlement and the actual earnings of the utility on a 50:50 basis with its customers. As discussed in Part III, Section C, Tab 2 Revenue Requirements, Terasen Gas proposes to return the projected balance of the Earnings Sharing deferral account at the beginning of 2010 to customers through Rate Rider 3 over the two year term of this RRA, along with the end-of-term capital incentive mechanism amount. Any variances between the projected amount and the amount determined based on final rate base and earnings figures for 2009, will be adjusted through the rider in 2011. Supporting calculations can be found in Part III, Section C, Tab 13, Schedule 70.

Terasen Gas believes that the deferral accounts requested above serve to add value to customers and our shareholder and appropriately address uncontrollable matters and future responses to Energy Policy.

g) Cash Working Capital

Cash Working Capital is defined as the average amount of capital provided by investors in the Company to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The periods are usually expressed in terms of lead or lag days, and are supported by a Lead Lag Study. Cash working capital of $6.8 million credit in 2010 and $6.1 million[196] credit in 2011 has been included in rate base.

Assurance that the Cash Working Capital requirements of the Company are accurately stated is best obtained through an updated Lead Lag Study most recently updated in 2009.[197] Using the results of this Lead Lag Study, Terasen Gas believes that the Cash Working Capital presented in this RRA for 2010 and 2011 is an accurate reflection of the Company's requirements.

Prior to 2009, the last Lead Lag Study performed by Terasen Gas was in 1991. As part of the 2004-2008 Multi Year PBR Application, the Revenue Lag Days of the 1991 Study were amended to reflect the

[196] Part III, Section C, Tab 13, Schedules 8 and 9, Line 20, Column (5)
[197] See Appendix I-2 for a copy of Lead Lag Study

repatriation of Lower Mainland customers from BC Hydro in 2002. No other changes have been made since that time.

A brief recap of the 2009 Lead Lag Study process and results follows.

Lead Lag Study Process

- The study used 2007 as a Test Year which was the most recent full year of available data.
- The study is similar in scope and methodology to its predecessor study performed in 1991.
- The study has undergone a review by KPMG Management Consultants.
- The results of the study have been compared to the amended results of the 1991 study.

Lead Lag Study Results

- When applied to 2010 and 2011 forecast data the 2009 Lead Lag Study results in a Net Lag of 0.6 and 0.8 days[198] respectively. This compares to the amended results of the 1991 Lead Lag Study which when applied to the 2009 Decision resulted in a Net Lead of 5.0 days.
- This difference of 5.6 for 2010 and 5.8 days for 2011 is made up of an increase in Revenue Lag Days of 3.8 and a decrease in Expenditure Lead Days of 1.8 and 2.0 respectively.
- The increase in Revenue Lag Days is primarily attributable to the increased usage of on-line bill payment by Terasen Gas customers over the past several years. On-line banking enables a customer to choose future dates of payment for settling their bills. This simplifies the process of delaying bill payment until payment due date.
- The decrease in Expenditure Lead Days is primarily attributable to Carbon Tax becoming a more significant component of total expenditures and having proportionately lower lead days.

When applied to the revenues and operating expenses for 2010, this change in net days results in an increase of approximately $20 million in cash working capital ($14 million from revenues and $6 million from expenses).

The working capital requirements that have been included in this RRA appropriately reflect the most recent Lead Lag Study results and represent the amounts required to compensate Terasen Gas for the timing differences between when expenditures are required to provide service and when collections are

[198] Part III, Section C, Tab 13, Schedule 58, Line 15

received for that service. TGI, therefore, requests approval of the adoption of the cash working capital lead lag days as set out in the Lead Lag Study (Appendix I-2).

h) Gas-in-Storage and Other Working Capital

The main component of other working capital is gas-in-storage inventory. The forecasted 13 month average balances are $100.5 million in 2010 and $114.8 million in 2011 (Table C-8-2). The forecasted amount of Gas in Storage is subject to significant risk, both in terms of forecasting volumes that will be held in storage, and in terms of forecasting future commodity prices. For purposes of this RRA, the forecasted volumes and prices are consistent with the assumptions used in forecasting the gas costs and the balances of the CCRA and MCRA deferral accounts. Both of these accounts are subject to interest treatment on variations between the forecasted balances in the accounts that are included in rate base, and the actual balances in the accounts through the year. With this RRA, Terasen Gas is proposing to extend this interest treatment to the gas in storage inventory balance. The booking of interest on variances reduces the likelihood of large carrying cost benefits or losses accruing to either the Company or to customers. Any amounts deferred during 2010 and 2011 will be added to rate base and amortized in rates beginning in 2012.

Consistent with Commission Order No. G-112-04, customer security deposits are no longer included as a component of the working capital calculation. They are treated as part of the unfunded debt, and the difference between the interest rate applicable to security deposits and the unfunded debt rate is included in the deferred interest variance account.

i) Lease-in–Lease-Out Benefit

The LILO Customer Benefit captures the benefit to customers of the Company's LILO agreements. The benefit represents the depreciated value of the original customer benefit calculation for each LILO agreement, calculated as 50 per cent of the net present value of Terasen Gas' benefit on an after tax basis, as agreed to in Commission Order No. G-108-01.

j) Summary

Terasen Gas must be accorded the opportunity to earn a return on its investment in rate base. The rate base amounts that have been forecast for 2010 and 2011 incorporate required expenditures to meet the expectations of our growing customer base, make improvements related to system integrity and reliability, invest in systems required to support customer growth, ensure that the deferred charges we employ are adding value to customers and the shareholder; and finally support the energy policy and reflect new energy solutions.

9. Capital Expenditures

The Company's capital expenditures involve small and large projects of many types required to: maintain the safety and integrity of the distribution and transmission facilities; meet increasing regulatory requirements and public expectations; enable the Company to provide service to new customers; respond to the information needs and inquiries of customers; and provide the information and systems necessary to support the business.

As part of this Application and discussed later on in this section under CPCN, Terasen Gas is proposing a change to the CPCN filing threshold, from $5 million to $20 million. Increasing the threshold level for CPCN filings would have the effect of increasing regular base capital in all categories of expenditures on a relative basis when comparing 2010/2011 to years 2009 and prior when the CPCN threshold was set at $5 million.

To continue to provide safe, reliable, and cost-efficient service to customers, Terasen Gas proposes the following 2010 and 2011 capital budgets (excluding AFUDC and CPCN projects) as outlined in the table below.

Table C-9-1: 2010 – 2011 Proposed Capital Expenditures[199]

	2009 Projection	2010 Forecast	2011 Forecast
Category A			
Mains	8.9	8.3	8.8
Services	15.0	13.8	15.1
New Meters & Meters Recalled	14.0	19.7	20.7
Total Category A Nominal	**37.9**	**41.8**	**44.6**
Total Category A Real	**37.9**	**41.0**	**42.9**
Category B			
Transmission Plant	11.3	12.2	25.2
Distribution Plant	8.7	8.4	6.8
Total Category B Nominal	**20.0**	**20.6**	**31.9**
Total Category B Real	**20.0**	**20.3**	**30.7**
Category C			
IT	16.0	18.0	18.0
Non-IT	14.9	16.8	16.7
Total Category C Nominal	**30.9**	**34.8**	**34.7**
Total Category C Real	**30.9**	**34.1**	**33.3**
Total Nominal	**88.8**	**97.2**	**111.2**
Total Real	**88.8**	**95.4**	**107.0**
Figures exclude AFUDC and Capitalized Overheads			
Average Customers	833,798	839,949	845,633
Total Nominal $/Customer	**106**	**116**	**131**
Total Real $/Customer	**106**	**114**	**127**

Note: Expenditures in $million; Real totals in 2009 values

Terasen Gas believes the overall forecasted capital costs are prudent and required to meet the evolving needs of customers.

As indicated in Part III, Section B, Tab 1, Table B-1-26, the total approved capital spending in the 2003 Decision was $86 million on a nominal dollar basis or $97 million on a real dollar basis. Capital spending on a per customer basis was set at $111 per customer on a nominal dollar basis or $125 on a real dollar basis. Excluding the effects of the change in the CPCN filing threshold, the 2010 and 2011 proposed capital budgets compare well to the amounts approved by the 2003 Decision. On total expenditure basis, 2010/2011 proposed capital expenditures (real dollar) is approximately $93 million[200] per year compared to $97 million as provided for in the 2003 Decision. On a per customer basis, 2010/2011

[199] Total nominal dollars per Part III, Section C, Tab 13, Schedule 43, Line 4

[200] Excludes $2 million in 2010 and $16 million in 2011 of Category B Transmission expenditures that would have been classified as CPCNs.

expenditures per customer (real dollar) is approximately $110 per customer compared to $125 as provided for in the 2003 Decision.

The following is a discussion of the categories of capital with the supporting rationale outlined for the 2010 and 2011 budget.

a) Budget Rationale

(1) CATEGORY A - CUSTOMER DRIVEN CAPITAL – MAINS, SERVICES AND METERS

Category A capital expenditures include the installation of new mains, services and meters and expenditures for gas meters utilized for meter exchange activities to serve the existing customer base.

The primary drivers for the Category A type of expenditures are the number and type of new services and mains. These in turn are driven by customer additions, which are dependent on new housing, development activity and market capture. A secondary driver for Category A expenditures is the number of meters exchanged or recalled each year which is determined by the age of the meter fleet in service and Measurement Canada Standards.

Below is a summary of the anticipated Category A expenditures for 2010 and 2011.

Table C-9-2: 2010 – 2011 Forecast Mains, Services & Meters Capital Expenditures

	2009 Projection	2010 Forecast	2011 Forecast
Mains	8.9	8.3	8.8
Services	15.0	13.8	15.1
New Meters & Meters Recalled	14.0	19.7	20.7
Total Nominal	**37.9**	**41.8**	**44.6**
Total Real	**37.9**	**41.0**	**42.9**
Average Customers	833,798	839,949	845,633
Total Nominal $/Customer	**45.5**	**49.8**	**52.8**
Total Real $/Customer	**45.5**	**48.8**	**50.8**

Note: Expenditures in $million; Real totals in 2009 values

(a) Mains

Forecast new mains activity, together with unit costs and capital expenditure levels are summarized in Table C-9-3, below.

Table C-9-3: Forecast Mains Activities, Unit Costs & Expenditures

	2009 Projection	2010 Forecast	2011 Forecast
Activities (metres)	115,305	105,504	110,213
Unit Costs ($/metre)	$ 77	$ 79	$ 80
Expenditures ($millions)	$ 8.9	$ 8.3	$ 8.8

Forecast mains activity levels, forecast mains unit costs and capital expenditure forecasts for mains are described in the following three sections.

(i) Mains Activity Levels

The forecast level of mains activity is derived indirectly from the customer additions forecast. Customer additions determine the forecast quantity of Service additions based on a three year (2006-2008) historical ratio of 0.78 Services per Gross (new) customer addition. In turn, the forecast mains activity level is determined by using a three year (2006-2008) historical ratio of 15 metres of new main per new Service addition. A three year historical ratio is used to smooth out the minor annual fluctuations in the ratio as well as to recognize any trends materializing in the past three years of actual data.

Projected new mains activity levels for 2009 are 115,300 metres based on the 2009 forecast new customer additions and the forecasting methodology described above. Using the same methodology, in 2010 and 2011, new mains activity has been forecast at 105,504 and 110,213 metres, respectively.

(ii) Mains Unit Costs

The forecast unit costs for 2010 and 2011 reflect in part the pressures Terasen Gas has experienced over the past five years, including managing the demographic challenge (recruiting, training and outfitting apprentices to replace retiring workers), managing construction with a multitude of municipalities, inflationary increases in wages, vehicles, contracts and materials. Other factors which negatively impacted overall unit costs during this period are location of pipe, travel times and contractor mobilization in the Interior and pavement etc. and traffic control requirements in the Lower Mainland. Forecast unit costs also reflects the recent shift of more of this type of work activity to Terasen Gas crews. Terasen Gas maintains workforce levels sufficient to respond to emergencies. Consequently, Terasen Gas unit costs are historically higher than contractors due to having to periodically interrupt projects to respond to emergencies. 2010 and 2011 forecast unit costs are based on 2009 projections and reflect inflationary increases for both the Terasen Gas and contractor workforces. The composite inflationary increase used for 2010 is 2 per cent and for 2011 is 2 per cent.

(iii) Mains Expenditures

The new mains expenditures forecast for 2010 and 2011 are $8.3 and $8.8 million respectively. Total new mains expenditures are largely variable and rise and fall with activity levels. The forecast decreased activity levels of 105,504 metres in 2010 and 110,213 metres in 2011 (see Table C-9-3) are reflected in the aggregate expenditure requested. Experience with unit costs achieved under the PBR Period and recently during the economic downturn, together with a shift in this work activity to Terasen crews and forecasted increases in labour and vehicle rates, form the basis for the forecast unit costs. The forecast unit costs when applied to the forecast activity level drive the overall new mains expenditure requirement.

Terasen Gas believes these expenditures are prudent and reasonable in providing for distribution main extensions to serve new customers and effectively use emergency response personnel time that would otherwise be idle.

(b) Services

Service expenditures in Category A consist of a variety of service types for new customers. These include new and conversion DP and IP services to single and multi-family dwellings, gas stub service from the main, services installed from the stub, vertical header subdivisions (a vertical service line system within a building such as a high-rise) and DP and IP new or conversion service header mains and DP and IP service header laterals. Service header mains are distribution mains installed on private property (i.e. multi-family strata owned complexes).

There are two basic considerations in understanding the forecast service expenditures level. These are level of activity (number of services installed, number of service header mains installed) and aggregate unit cost to install the service (dollars per service) and/or service header main (dollars per metre).

Forecast services and service header mains activities, together with unit costs and capital expenditure levels are summarized in Table C-9-4, below. Forecast services activity levels are discussed in Section (i) below with forecast services unit costs reviewed in Section (ii), and capital expenditure forecasts for services described in Section (iii).

Table C-9-4: Forecast Services Activities, Unit Costs & Expenditures

	2009 Projection	2010 Forecast	2011 Forecast
Net Customer Additions	6,120	5,600	5,850
Gross Net Customer Additions	9,600	8,784	9,176
Ratio of Service Additions to Gross Customer Additions	0.78	0.78	0.78
Activities:			
Service (risers)	7,510	6,872	7,178
Service Header Mains (metres)	34,589	31,821	33,100
Unit Costs:			
Services - All Workforces (per riser)	1,650	1,662	1,736
Service Header Main - All Workforces (per metre of Main)	76	77	77
All Services $ per Service (riser) - All Workforces	2,000	2,014	2,105
Expenditures ($millions)			
Services	12.4	11.4	12.6
Service & Vertical Header Mains	2.6	2.4	2.5
Services Total (Pre-CIACs)	15.0	13.8	15.1

(i) Services Activity Levels

The 2010 and 2011 forecast level of services activity is derived directly from the gross customer additions forecast, as discussed in Part III, Section C, Tab 4, Table C-4-1. Using a current three year historical average (2006-2008), the ratio of Service Additions to Gross Customer Additions calculated is 0.78. A three year historical ratio is used to smooth out the minor annual fluctuations in the ratio as well as to recognize any trends materializing in the past three years of actual data. Service additions are forecast to decline with the forecast reduction in customer additions. Service header mains are forecast to decline from 2008 levels at the same percentage rate as the Service additions decline (28 per cent).

Projected service additions activity levels for 2009 are 7,510 services and are based on 2009 forecast new customer additions and the forecasting methodology described above. Using the same methodology, in 2010 and 2011, new service activity has been forecast at 6,872 and 7,178 services, respectively. The service header mains forecast for 2009 is 34,589 metres and was reduced from 2008 activity levels by the same percentage as the services activity reduction (-28 per cent). The same methodology was applied to 2010 and 2011 where the service header mains forecast is 31,821 and 33,100 metres respectively.

(ii) Services Unit Costs

Aggregate service unit cost, which is the second consideration in establishing the forecast expenditure requirement for new services, is calculated by taking all services costs and dividing by the number of risers (services) installed. For more detailed discussion of historical unit costs, please refer to Part III, Section B, Tab 1, Table B-1-29.

The forecast unit costs for 2010 and 2011 reflect the pressures Terasen Gas has experienced over the past five years under the PBR Agreement: the rebuilding of crews in 2007, the downturn in the economy in late 2008 and lower services activities in 2009. These factors have resulted in a higher percentage of services work being completed by the Terasen Gas workforce. In the absence of work, the install contractors are going through a period of significant layoffs.

Forecast unit costs are based on 2009 projections and reflect inflationary increases and accounting changes (i.e. IFRS) for both Terasen Gas and Contractor workforces and equipment. The inflationary increases projected are 1 per cent for 2010 and 5 per cent for 2011. The inflation amount in 2011 is higher than the Terasen Gas field contractual wage increase of 3 per cent as a result of expected changes in employee pension and benefits and vehicle inflation.

(iii) Services Expenditures

Service expenditures for 2010 and 2011 are forecast at $13.8 and $15.1 million respectively. Total services expenditures are largely variable and rise and fall with activity levels. IFRS accounting changes (primarily the treatment of training and vehicle depreciation costs), discussed in Part III, Section C, Tab 11, account for a reduction of expenditures by $0.6 million annually for 2010 and 2011.

The forecast decreased activity levels, together with recent unit cost history adjusted for inflation and IFRS accounting changes form the basis for the aggregate expenditure requested. TGI believes these expenditures are prudent and reasonable in providing services and service header mains to service new customers.

(c) Meters – New and Replacement

The two main considerations in understanding the forecast meter expenditure level are: (1) the level of activity (meters purchased and installed or exchanged) ; and (2) the unit cost to purchase, fabricate and install the meter (dollars per meter). A summary of 2009 projections as well as 2010-2011 forecast new and replacement meter activities, unit costs, and expenditures follows in Table C-9-5, below. The level of activities combined with the unit cost form the basis for the total expenditures.

Table C-9-5: Forecast Meters Activities, Unit Costs, Expenditures

	2009 Projection	2010 Forecast	2011 Forecast
Activities			
Meters - New	6,120	5,600	5,850
Meters - Exchange	46,700	60,255	60,175
Meters - Total	52,820	65,855	66,025
Unit Costs ($/meter)			
Meters	265	299	314
Expenditures ($millions)			
Meters - New	1.5	1.5	1.6
Meters - Exchange/Other	12.5	18.2	19.1
Meters - Total	14.0	19.7	20.7

(i) Meters Activity Levels

The forecast level of meter activity is typically derived from the sum of the customer additions and the meter exchange forecasts. The meter forecast for new customers is derived directly from the forecast of customer additions using a one to one ratio. The forecast level of meter exchange activity to service existing customers is driven by life expectancy of meters and the total size of the meter population.

In the past four years, there were two specific drivers that significantly influenced the meter recall schedule for Terasen Gas. Prior to 2006, Terasen Gas managed the residential meter fleet to a 28 year life span enabled by one maintenance and recondition operation at the midpoint of this 28 year life. This resulted in a meter recall frequency of 14 years. Communications with vendors, ongoing discussions within the Canadian Gas Association Measurement Committee and the Company's own internal analysis, provided Terasen Gas the confidence to target a 20 year life span for the residential meter fleet without a mid-life recondition operation. This allowed Terasen Gas to temporarily reduce the number of meter recalls from between 40,000 to 50,000 meter recalls annually to a range between 25,000 to 35,000 recalls annually over the period 2006 - 2008. The reduction in the number of recalls brought the demographics of the meter fleet in line with a 20 year life expectancy, which provided both customers and the shareholder with the cost benefits of previous investments in the fleet.

Beginning in 2009, the number of meter exchanges has increased as it is no longer viable to maintain the lower exchange levels due to the aging meter fleet. In addition, during the late 1990s, certain batches of meters comprised with components constructed with less durable materials were installed within the meter fleet. Although the vendor has since re-designed the meter to address this concern, TGI believes it is prudent to proactively remove these meters from the fleet to prevent unscheduled failures. As such, in order to address the aging fleet and remove from service the meters with a predicted shorter life span, the forecasted meter recalls must be increased to 60,000 recalls annually through the period covered by this application. We believe this meter recall frequency reflects the long term objectives of the fleet management program and will ensure the customers of Terasen Gas will continue to receive service that is both cost effective and reliable.

(ii) Meters Unit Costs

Meter unit cost, which is the second consideration in establishing the forecast expenditure requirement for meters, is influenced by the type, size, and design of the meter, installation, fabrication and exchange conditions and the timing of bulk meter purchases. A blended unit cost of all customer types is used for meter exchanges and installs. Meter unit costs can range from $75 to $100,000 depending on the customer requirements. The meter unit cost consists of approximately 50 per cent labour and 50 per cent non-labour costs.

Unit costs for meters for 2010 and 2011 are based on 2009 projections adjusted for increased regulator replacement program expenditures, IFRS accounting changes, inflation on labour (2 per cent in 2010 and 6 per cent in 2011) and materials (2 per cent). Meter material costs have been relatively stable with CPI type inflation however Terasen Gas labour rates are fluctuating in both 2010 and 2011 due to wage rate increases of 3 per cent, pension and benefit changes and the impact of IFRS accounting changes.

(a) Meters Expenditure Levels

The Meters expenditures forecast for 2010 and 2011 are $19.7 and $20.7 million respectively. Meters expenditures are largely variable and rise and fall with meter exchange and customer additions activity levels. The forecast decrease in customer additions activity levels and the forecast increase in meter exchange activity levels are reflected in the aggregate expenditure requested. Included in the Meters expenditure requirement is an amount of $2.1 million for Terasen Gas' ongoing regulator ever-greening program. In 2003, Terasen Gas began a program of replacing regulators at the same time as the meter exchanges were completed at the customer's premise. TGI believes these expenditures are prudent and reasonable in providing meters to serve new and existing customers.

(d) Category A Summary

The forecasts for 2010-11 have been developed in a manner consistent with recent historical data and are based on projected customer additions and current unit costs escalated by inflation. The ratios of mains and service lines used to develop the forecast activity are consistent with 2006-2008 averages. The number of meter exchanges has increased from the PBR Period as it is no longer viable to maintain the lower exchange levels due to the age of the meter fleet and anticipated early failures for some batches of meters purchased in the 1990's.

Customer additions, which drive main, service and meter activity, are expected to decline in 2009 with forecasted numbers 34 per cent lower than the 2008 actuals of 9,256. This declining trend is expected to continue into 2010/2011 as customer additions decline further to approximately 5,600 for 2010 (39 per cent lower than 2008 actuals) and 5,850 for 2011. For further information on forecast customer additions see Part III, Section C, Tab 4, Table C-4-1.

As previously noted, a portion of the costs of Category A activities is paid directly by new customers. CIAC are funds received from customers and developers to offset Category A expenditures when the main extension fails Terasen Gas' economic test or when the estimated service line installation cost is greater than the Service Line Cost Allowance. This fee is treated as a CIAC. CIAC are not included in the Category A capital forecasts but are accounted for separately. CIAC additions for Category A capital for 2010 - 2011 are forecast at $1.0 million and $0.7 million, respectively. The detailed forecast CIAC for 2010/2011 can be found in Table C-9-12.

The Category A capital costs forecast for 2010 and 2011 represent the level of this type of capital required to provide safe, reliable and efficient service to new and existing customers of Terasen Gas. TGI seeks approval of a Category A capital plan of $41.8 million in 2010 and $44.6 million in 2011 in order to provide the products and services that new and existing customers expect.

(2) CATEGORY B - TRANSMISSION AND DISTRIBUTION SYSTEMS INTEGRITY AND RELIABILITY

The capital expenditures within Category B include gas system improvements to add capacity to the distribution and transmission system in order to meet customer growth and to ensure the safety and reliability of the system. Projects of a special nature, generally those with project budgets greater than $5 million, have typically been reviewed by the Commission through a separate CPCN process.

For Transmission, the key tool used to determine the capital requirements is the Company's long range (typically 20 years) capacity addition plan, using a system hydraulic process. It accounts for the hourly demand variations of heat sensitive load, the amount of line pack available within the transmission system, as well as any midstream benefit. Long range planning for transmission facilities is necessary to account for the long lead times for typical large infrastructure projects (i.e. regulatory approvals, public consultation, conceptual design, detailed engineering, and construction schedules). The plan optimizes the transmission capacity additions to meet the forecasted demand from core marketing customers under design temperature conditions and firm transportation from industrial customers. It is updated annually and reported in the Company's Resource Plan.

Similarly, for Distribution, the key tool used to determine the capital requirements necessary for these facilities is the Company's five-year infrastructure plan. This plan is developed using a detailed network analysis process that incorporates the needs of each community with different weather patterns, growth rates, geographic location, and specific customer attributes and is updated annually. The planning cycle starts with gathering pressure information from hundreds of points throughout the system, which is then adjusted for weather differences. Computer programs are used to analyze the flows on gas distribution grids and the transmission system to model growth and to develop a plan that minimizes the long-term costs of meeting customer needs while meeting appropriate codes and standards. After flow requirements are understood, the other components of the system (such as gate stations, odourant facilities, metering, etc.) are analyzed to ensure everything meets the design conditions. Once the network analysis of the distribution system is complete, specific projects to meet the load growth are determined, evaluated and prioritized. The evaluation is centered on ensuring that undue risk is not taken with regard to meeting peak day obligations or compromising system integrity. Where possible, procedures such as manual control are examined as a way to defer the requirement for projects. The final output of the review is the five-year integrity infrastructure plan which is then used to create the five-year budget for Category B expenditures.

(a) Category B Expenditures 2010-2011

The forecast expenditures for Distribution and Transmission plant are outlined in Table C-9-6 below. The forecast of Category B expenditures for 2010 -2011 was based on identifiable projects and the five year infrastructure plan and represents a prudent and reasonable level to provide reliable service.

Table C-9-6: Forecast Transmission and Distribution Plant Expenditures

	2009 Projection	2010 Forecast	2011 Forecast
Transmission Plant under $5 million	11.3	10.0	9.2
Transmission Plant over $5 million	-	2.2	16.0
Distribution Plant under $5 million	8.7	8.4	6.8
Total Nominal	**20.0**	**20.6**	**31.9**
Total Real	**20.0**	**20.3**	**30.7**
Average Customers	833,798	839,949	845,633
Total Nominal $/Customer	**24.0**	**24.6**	**37.7**
Total Real $/Customer	**24.0**	**24.1**	**36.3**

Note: Expenditures in $million; Real totals in 2009 values

The Category B expenditures for 2010 - 2011 presented in this Application are higher than the average spending during the 2004 – 2009 PBR Period, and that provided for in the 2003 Decision, primarily as a result of the Company's proposed change to the CPCN filing threshold, from $5 million to $20 million. As highlighted in Table C-9-6, line item Transmission Plant over $5 million, changing the CPCN filing threshold will lead to an increase in expenditures reported in Category B for 2010 and 2011 respectively of $2 million and $16 million per year, expenditures that otherwise would have been reported under CPCN status. Details of these projects are outlined under Section (ii) Transmission Category B Capital below.

Excluding the effect of the proposed change to the CPCN filing threshold, the anticipated level of Category B expenditures for 2010 and 2011 is comparable to prior year actuals and the 2003 Decision. TGI believes it is also a prudent and reasonable amount of capital investment, particularly when considered in terms of the nature of the Terasen Gas system and its age. Terasen Gas services a large and diverse customer base with approximately 21,000 km of distribution and transmission pipeline system, hundreds of gate stations, eight compressor stations and a LNG facility. Much of the infrastructure is over forty years old and requires a significantly higher level of expenditures when compared to new facilities to ensure that the Company meets its commitment to public safety, and its obligation to provide reliable service.

(i) Distribution Category B Capital

Investments in Category B Capital are required for the distribution system to maintain a high degree of system availability while protecting the public, customers and employees. Category B type of expenditures mitigate the risk of loss from system outages and business interruptions. Safety, reliability and growth expenditures are becoming increasingly important as insurance deductibles have escalated substantially for system outages and business interruption.

Table C-9-7 below summarizes Category B – Distribution plant for 2010 and 2011. The forecast was developed as discussed earlier, based on specific identifiable projects in the forecast period, together with the five-year infrastructure plan. System improvements, required for customer growth are projected to be $2.2 million in 2010 and $1.9 million in 2011. Station telemetry and odorant upgrades, required by customer growth and changes to facility requirements (security, seismic, operating, safety) amount to $3.2 million of Category B expenditures in 2010 and $3.9 million in 2011. The remaining integrity and reliability related dollars of $3.1 million and $1.0 million are required for miscellaneous cathodic protection, valve sectionalization and distribution lateral projects in 2010 and 2011.

Table C-9-7: Forecast Distribution Plant Expenditures

	2009 Projection	2010 Forecast	2011 Forecast
System Improvements	4.0	2.2	1.9
Station Upgrades	3.8	3.2	3.9
Miscellaneous	0.9	3.1	1.0
Total Nominal	**8.7**	**8.4**	**6.8**
Total Real	**8.7**	**8.2**	**6.5**
Average Customers	833,798	839,949	845,633
Total Nominal $/Customer	**10.4**	**10.0**	**8.0**
Total Real $/Customer	**10.4**	**9.8**	**7.7**

Note: Expenditures in $million; Real totals in 2009 values

The forecast total of $8.4 million and $6.8 million for 2010 and 2011 respectively, which is lower than the past five years historical average of $9.9 million and comparable to the $8 million provided for the 2003 Decision, represents a prudent level when considered in terms of customer growth forecasts, the age of the system, provincial geography, public and consumer expectations for safety and reliability, environmental and legislative impacts and new provincial carbon emission reduction initiatives.

(ii) Transmission Category B Capital

The transmission-related capital expenditures within Category B include system capacity improvements to meet core customer growth, and expenditures related to ensuring safety and reliability of the transmission system, as well as to minimize impact to the environment. Most of the Category B projects cover a range of projects with values less than $1 million each, with some exceptions where mentioned.

Table C-9-8 below summarizes Category B – Transmission plant for 2010 and 2011. The proposed annual budgets for Category B Transmission expenditures are $12.2 million and $25.2 million, including $10 and $9.2 million in expenditures for projects under $5 million, for 2010 and 2011, respectively.

These amounts are higher than the $8.5 million annual average expenditures from 2004 to 2009, but the marginal increase over the 5-year average amount is only due to the inclusion of major inspection costs and capitalization of compressor overhauls as the result of IFRS requirement discussed in Part III, Section C, Tab 11, Accounting and Other Policies. Terasen Gas expects that ongoing Category B type of these expenditures will remain relatively constant into the future.

Table C-9-8: Forecast Transmission Plant Expenditures

	2009 Projection	2010 Forecast	2011 Forecast
Pipeline	6.9	7.3	19.0
Compression	1.6	1.2	1.3
LNG	0.2	0.5	2.1
Miscellaneous	2.6	3.2	2.7
Total Nominal	**11.3**	**12.2**	**25.2**
Total Real	**11.3**	**12.0**	**24.2**
Average Customers	833,798	839,949	845,633
Total Nominal $/Customer	**13.6**	**14.6**	**29.8**
Total Real $/Customer	**13.6**	**14.3**	**28.6**

Note: Expenditures in $millions; Real totals in 2009 values

Pipeline expenditures for upgrading and replacing pipeline assets are anticipated to be $7.3 million in 2010 and $19.0 million in 2011. This includes two significant projects: Kootenay River Crossing Replacement and Huntingdon Alternative Interconnection for Security of Supply.

The 8 inch aerial crossing of the Kootenay River at Shoreacres, a component of Castlegar-Nelson 6 inch pipeline, is reaching its structural life expectancy. The options being considered to replace the existing crossing include a pipeline route, a horizontal directional drilling pipeline crossing, and a replacement aerial crossing. The replacement is expected to be in-service in 2011 with an order of magnitude cost estimate at $6.2 million.

The Huntingdon-Sumas hub is a composite of interconnecting facilities from the Westcoast Pipeline, Terasen Gas and Williams Pipeline. The Terasen Gas' Huntingdon Flow Control Station (Huntingdon) located at the hub is the single supply point to over 570,000 gas customers located in the Lower Mainland, Sunshine Coast and Vancouver Island. A single event failure at this supply point in a relatively short duration (3-4 hours) would create a significant gas service interruption which potentially could take weeks to recover. For example, Terasen Gas nearly experienced a large outage in November 2008, when it was forced to shut-in all gas supply to the Lower Mainland and Vancouver Island for nearly 3 hours with no alternative, due to damage at a single-point of failure at Huntingdon. To minimize these risks, the proposed interconnection, consisting of a new interconnect with the Westcoast Pipeline upstream of Huntingdon, a new pipeline from the new interconnect to the Coastal Transmission System downstream of Huntingdon, and a measurement and flow control facility, is to provide an alternative supply route to the gas customers in the event of a failure at the Huntingdon-Sumas hub. The proposed alternative interconnection is estimated at $12.2 million and is expected to be in service in 2011.

Pipeline relocation and road crossing upgrade costs are estimated at $1.2 million and $1.1 million for 2010 and 2011, respectively. Some portion of the actual expenditures may be recovered depending on third parties involved, and subject to negotiation, legal proceedings, and insurance claims. Natural hazards from geotechnical and hydrological sources are proactively managed and areas of potential high risks are to be systematically remedied at an annual expenditure of $0.6 million. The potential of washouts of pipelines from spring freshets and winter storms is a recurring concern in system reliability, and a contingency allowance of $1.0 million is planned to facilitate the subsequent reactive remedial work from a major washout.

Expenditures for Compression are anticipated to be $1.2 million in 2010 and $1.3 million in 2011. These projects will reduce the risk of having inadequate capability to meet core loads during peak season due to obsolete control components and will increase unit availability and reliability for long term gas nomination customers.

LNG expenditures include upgrades to existing LNG storage facilities such as piping, insulation, heat exchangers, valves, regulators, controllers, and other components to ensure safe and efficient operations. These expenditures are anticipated to be $0.5 and 2.1 million in 2010 and 2011 and include upgrades to boil-off compression at the Tilbury LNG Facility, and a new LNG road tanker and a high volume gas fired LNG vaporizer for the temporary supply of natural gas for planned or emergency work while maintaining gas service to customers. Not included in the forecast are expenditures related to the purchase of land adjacent to the Tilbury LNG plant. The Company intends to file a CPCN Application with the Commission for approval of this purchase in 2009.

Expenditures in the Miscellaneous category include a combination of projects to ensure the integrity and reliability of the Transmission system including cathodic protection, minor pipe replacements, and upgrades to the SCADA system used to monitor and control the operation of the Terasen Gas system to meet its customer gas requirement. To accommodate technology and business changes, the system must be regularly enhanced to meet the changing business and operating requirements as the SCADA system must operate reliably and without interruption.

The proposed level of expenditures is considered prudent and is required to ensure that Terasen Gas' commitments to public safety, code requirements, environmental performance and its obligation to provide reliable service are met.

(3) CATEGORY C - ALL OTHER PLANT

Capital expenditures for all other plant are included in Category C and split between IT and "Non-IT". Non-IT expenditures include costs associated with plant, labour, and equipment required for the alteration and replacement of gas mains, gas services, and pressure regulator stations; the acquisition or leasing of land; facilities including station buildings, facilities equipment; telecommunications infrastructure; specialized tools and equipment; and radio system upgrades. IT expenditures include costs associated with information technology hardware, infrastructure, and software requirements.

(a) Category C Expenditures 2010 - 2011

Table C-9-9 below summarizes Category C – All Other Plant for 2010 and 2011.

Table C-9-9: Forecast All Other Plant Expenditures

	2009 Projection	2010 Forecast	2011 Forecast
IT Projects	16.0	18.0	18.0
Non-IT Projects	14.9	16.8	16.7
Total Nominal	**30.9**	**34.8**	**34.7**
Total Real	**30.9**	**34.1**	**33.3**
Average Customers	833,798	839,949	845,633
Total Nominal $/Customer	**37.0**	**41.4**	**41.0**
Total Real $/Customer	**37.0**	**40.6**	**39.4**

Note: Expenditures in $millions; Real totals in 2009 values

In 2010, of the $41.4 million in total expenditures, $21.6 million or 52 per cent will be incurred in maintaining the integrity of the distribution infrastructure, acquiring real property and supporting facilities, upgrading communications and telemetry systems, and providing tools and equipment. The remaining capital, 48 per cent or $19.8 million, will be incurred for the replacement, acquisition, and implementation of IT hardware, software, and related infrastructure. The expenditures are discussed further below.

(b) IT Capital

IT expenditures in Category C excluding those approved through CPCNs are categorized into three areas:

- new implementation for business units;
- technology sustainment and upgrading; and
- security / risk mitigation

A key driver of IT expenditures is changing business process needs. The operating departments within Terasen Gas continually seek to identify more efficient or effective processes as well as to permit the Company to preserve efficiencies that have been attained. As a result, investments in information technology and supporting applications are required. In addition, IT capital expenditures are also made to allow the operating departments to comply with changing regulations and external requirements that demand compliance.

A second requirement for IT expenditures is the need to sustain and upgrade hardware and software. Keeping up with evolving technologies is a struggle for all companies. New infrastructure and new application versions have become commonplace throughout the IT industry. At times, the turnaround from new to discontinued application versions can be as short as 18 months. Larger application vendors (i.e. GE Smallworld and SAP) have scheduled version updates that incorporate new changes and additional functionality to the application, incorporate correction patches into the core system and take advantage of improvements in infrastructure. Many software and hardware vendors typically abandon older versions and withdraw support as their new version becomes available. Consequently, continuous sustainment investments must be made to replace these older applications and technologies. This sustainment cycle also requires the upgrading and replacement of desktop computer technologies in order to operate more advanced versions of the software applications.

The focus on IT security has increased steadily. A dramatic shift in security threats began early in 2001. This is primarily due to the increased use of Internet e-mail functionality and the escalating threat of external hackers. These security threats have increased to exploit weaknesses in all areas of network and software applications. The increased use of the Internet to support business processes requires additional investment in the protection of those processes and associated data. IT security must now be implemented with a depth model that uses many layers of differing protection but still offers the capability to support business requirements.

Recent events have also caused all companies in North America to evaluate their DRP. Historically, the Company had utilized a point solution strategy where certain key applications had remote fail-over capability. While this provided capabilities for a single application, it did not provide the breadth of a true DRP required for business continuity. Under the ownership of KMI, the Company had intended to utilize many of the resources made available by KMI for a more comprehensive and cost-effective DRP strategy. With the sale of Terasen to Fortis, these plans are no longer viable and the Company must now make the investment to mitigate the risk to the business and its customers.

The demand for IT capital investment is significant. It is the IT department's experience that the demand outpaces the Company's capacity to execute. It is also the Company's experience that not all projects that are implemented at the end of the year were identified during the prior year budgeting process. The capability of the business units to invest resources required to successfully implement new solutions must be balanced against operational demands.

Terasen Gas has implemented and continues to refine a governance structure to ensure that the demand for capital investment is prioritized, justified and authorized in a prudent manner. The current governance structure for investment of IT capital starts with the written justification or business case. The level of detail is commensurate to the level of complexity of the project. For projects such as annual refresh of desktops or servers, a simple one justification is deemed sufficient. In cases where the project impacts multiple business units or is of significant spend, greater levels of detail are required. Once the business case is approved by the respective vice president as a business unit priority, it is submitted to the Utility Operating Committee Capital Management group. This group consists of the key representatives from IT, Finance, Regulatory, Distribution, Transmission, Marketing, and Engineering Services. It is the responsibility of this group to review the business cases and collectively determine the appropriateness of the cost against the value and business priorities.

Terasen Gas believes the trend of higher investment in IT spend will continue to put demand on resources. In light of this trend, Terasen Gas is currently examining the scope and effort of implementing additional business processes and tools (i.e. portfolio management and benefit realization tracking) to these key assets. The capital request for IT investment is forecast at an amount in 2010 and 2011 that TGI can prudently execute while meeting the top priorities of the business.

The Company is forecasting an increase of $2 million in 2010 from the 2009 total of $16 million to a total of $18 million per year for each of 2010 and 2011. The currently identified projects for 2010 and 2011 have a combined cost of approximately $45 million. The discrepancy between the identified capital expenditures to date and the proposed capital budget of $18 million per year is due in large part to where each project is in terms of its respective justification development. Some projects are well understood, such as desktop refresh, and some are still in the initial concept development stage. It is Terasen Gas' experience that not all projects that are identified at the point of budget creation prove to withstand the further scrutiny of the business case development and prioritization process.

It is also Terasen Gas' experience that up to 30 per cent of projects that are approved by year end were not identified at the point where the initial budget was created. Business priorities change throughout the year as the company responds to changing internal priorities or external demands. It is critical that the Company have the flexibility to adapt its plans to these changing demands.

Another factor to be considered in determining the proposed budget is the Company's ability to execute on IT projects. For projects that require significant business involvement, the business must prioritize between IT project commitments and other business imperatives. Over the years, Terasen Gas has invested time and effort on technology that enables operational efficiencies and the integration of business processes spanning multiple business units. Consequently, TGI has to ensure that all affected groups are coordinated and have the same ability to commit resources to projects that impact them all. As a rule, Terasen Gas does not have the staffing levels in the operating departments to undertake multiple significant projects in IT, their own business initiatives and continue to provide quality service to its customers simultaneously.

TGI feels it is the responsible position to manage to a realistic ability to execute as opposed to budget on the assumption that all identified projects will be approved and executed. The forecasted expenditures are in line with historical spend. The incremental $2 million from 2009 to a total of $18 million per year in each of 2010 ad 2011 reflects the costs anticipated with the investment required for DRP.

(c) Non-IT Category C Capital Expenditures

The Non-IT Category C forecast for 2009 is $14.9 million with the proposed requirement for 2010 and 2011 being $16.8 and $16.7 million, respectively. Terasen Gas considers the proposed levels to be prudent and reasonable for projects and equipment in this category.

Table C-9-10: Forecast Non-IT Capital Expenditures

	2009 Projection	2010 Forecast	2011 Forecast
Main & Service Renewals/Alterations	5.0	7.3	7.6
Other Non-IT	9.9	9.5	9.1
Total Non-IT Projects	14.9	16.8	16.7
Average Customers	833,798	839,949	845,633
Total Nominal $/Customer	**17.8**	**20.0**	**19.7**
Total Real $/Customer	**17.8**	**19.6**	**18.9**

Note: Expenditures in $millions; Real totals in 2009 values

The Non-IT capital forecast is developed from an assessment of historical expenditure levels together with an allocation of funds for specifically identified projects and equipment.

The projected expenditure for Mains and Services Replacements and Alterations for 2010 is $7.3 million and for 2011 is $7.6 million, levels that are consistent with 2008 actuals of $7.5 million. Both the mains and services alterations component of this expenditure, generally driven and paid for by third parties and infrastructure construction activity, is projected to decrease in 2009 leading to an overall forecast of $5.0 million in this category. The results of the annual leak survey and the documented history of leak occurrence drive the determination of the appropriate level of expenditure for mains and services replacement on any particular section of the distribution system.

Terasen Gas is taking a number of steps where prudent to manage, mitigate, and avoid Non-IT Category C costs, including mains and services replacement expenditures, which consume a significant portion of the Category C budget. In its efforts to minimize unit costs while maintaining high standards of system reliability, Terasen Gas utilizes various alternative excavating techniques and trenchless technologies, as well as various alternative approaches to crew structure and job logistics. Furthermore, Terasen Gas continues to install new mains and services using polyethylene pipe which lasts longer than steel and is less subject to corrosive activity.

The projected expenditures for Other Non-IT projects for 2010 and 2011 are $9.5 and $9.1 million, respectively. These expenditures include purchases for tools and equipment, office furniture and equipment, and facilities. The projected tools and equipment expenditures of $3.6 million for 2010 and $3.5 million in 2011 are associated with replacing and upgrading existing equipment, together with additions to provide for technological and methodology changes. Maintaining the emergency response capability has required Terasen Gas to outfit more employees with broader tool sets, including pipe locators and temporary repair tools (squeeze-offs). In the Distribution area, ongoing changes in station components, such as gauges and telemetry, have driven the need to acquire up-to-date tools to measure and assess station flow indicators. The projected expenditures for the improvement or replacement of structures, office furniture, and equipment replacement are $3.2 million and $3.4 million.

Hazard mitigation activities, such as service overbuilds, exposed services, protection posts, venting hazards and others, are another major component of Other Non-IT Category C capital. Hazards are identified during leak surveys, meter reading or as a result of observations by Terasen Gas employees. Most hazards are created as a result of customer activities, i.e. building over the meter set or running line of the service. Each reported hazard must be validated, prioritized and scheduled for correction.

The centralized identification, tracking and management of hazards are relatively new at Terasen Gas, having been in place for approximately six years. As a result of the current downturn in the economy, Terasen Gas has the workforce capacity to increase the number of hazards addressed annually. Escalation of the hazards mitigation program will result in a reduction of risks to the public as well as Terasen Gas plant and employees. For 2010 and 2011, the requirement is $2 million annually. Terasen Gas must continue to meet all regulatory requirements including repairing hazards created by customer activities. TGI considers the annual amount being requested reasonable and prudent to mitigate identified hazards.

As the Distribution system ages and grows and additional hazards are identified, expenditures in Category C will increase. The pace of technological change continues to trigger expenditures to respond to and keep pace with industry and public expectations. Inflationary pressures from labour, materials and services continue. The forecast of $16.8 and $16.7 million for 2010 and 2011, respectively, for Non IT Capital represents a prudent level when considered in terms of customer growth forecasts, the age of the system and structures, provincial geography, public and consumer expectations for safety and reliability, and tool and equipment requirements.

(4) CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

Under the PBR Agreement, large capital expenditures over $5 million (excluding AFUDC) require additional approval from the Commission through a CPCN application process that discloses the project description and justification, establishes the timetable for the project, and details the legal, environmental, and other regulatory requirements. During the PBR Period, the Company has filed CPCN applications for projects exceeding $5 million (excluding AFUDC) and excluded these expenditures from the capital formula. The projects were added to rate base at the start of the year following when the project was put into service.

With the adoption of IFRS, Terasen Gas proposes a change to this accounting treatment in 2010 to allow future projects to be added into rate base when the project is put into service. IAS 16 requires that property, plant, and equipment ("PPE") commence depreciation when it is available for use. To allow depreciation to commence, the asset must be included in rate base. Therefore, the Company believes that it is necessary to include assets in rate base once the project is in service and available for use.

Terasen Gas also respectfully requests the approval to increase the CPCN filing threshold from $5 million to $20 million to improve regulatory efficiency and refocus resources to serve the requirements of new and existing customers. The Company will continue to act in the best interest of customers and demonstrate diligence through its approval process. TGI also believes that a $5 million dollar threshold is too low because it would capture projects that are generally not of a complex or significant nature and that do not warrant the cost and administrative burden on all parties of a separate CPCN Application. TGI believes that the threshold should be raised to $20 million to restrict CPCN Applications to projects that are relatively more complex and significant. All of TGI's capital projects would still be transparent to the Commission, customers and stakeholders in TGI's Revenue Requirements and Resource Plan applications. The Commission would have the discretion to require TGI to file a CPCN Application for any project, regardless of its cost. In addition, to the extent that capital projects between $5 and $20 million arise in 2011 and 2012 that have not been forecasted and incorporated into rates, such projects would not earn a return for the period the capital is in service during the 2010/2011 forecast period.

By increasing the threshold level for CPCN filings, this has the effect of increasing regular base capital (Categories A, B, C) expenditures on relative basis when comparing 2010/2011 to years 2009 and prior when the CPCN threshold was set at $5 million.

Considering a $20 million threshold, the table below identifies the forecast costs for major capital projects subject to CPCN applications for 2010 to 2011.

Table C-9-11: Forecast CPCN Expenditures ($millions)[201]

	2009 Projection	2010 Forecast	2011 Forecast
CPCNs			
Vancouver Low Pressure Replacement	0.3	-	-
Fraser River South Arm Rehabilitation	25.0	0.5	-
Anticipated CPCNs			
Okanagan Reinforcement Project	0.5	0.5	0.5
Customer Care Enhancement Project	7.5	49.7	57.8
Total Nominal	**33.2**	**50.7**	**58.3**
Total Real	**33.2**	**49.7**	**56.0**
Average Customers	833,798	839,949	845,633
Total Nominal $/Customer	**39.8**	**60.3**	**68.9**
Total Real $/Customer	**39.8**	**59.2**	**66.3**

Note: Expenditures in $millions; Real totals in 2009 values

(a) Fraser River South Arm Rehabilitation

As a component of the Coastal Transmission System, the Fraser River South Arm Crossings, comprised of a 24 inch and a 20 inch pipeline trenched across the river bed are potential for failure from a major seismic event. With the decision from BCUC granting a CPCN as per Order No. C-2-09, Terasen Gas is

[201] Total nominal per Part III, Section C, Tab 13, Schedule 43, Line 18

proceeding with the installation of horizontal directional drill pipelines of the same size and at the same location to replace existing buried crossings. The project is estimated to cost $27.3 million and is expected to be in service by 2010.

(b) Okanagan Reinforcement Project

The Interior Transmission System ("ITS") which transports gas to the Thompson, Okanagan and Kootenay regions in the interior of B.C. requires a system capacity addition as early as 2016 to meet demand due to forecast core customer market growth. In addition, FortisBC has indicated in the current draft of its 2008 Resource Plan that it is considering the addition of a gas fired generation facility in the Kelowna area possibly by the winter of 2014, which would accelerate the reinforcement schedule of the ITS. The option of the addition of a pipeline loop from Penticton to Naramata and a unit addition at Kitchener-B Compressor Station, and the alternative of a 1.0 Bcf peakshaving LNG facility to be located in the Northern Okanagan are under consideration. The $72.0 million in the budget reflects the total estimated cost for the pipe and compression option only.

(c) Customer Care Enhancement Project

Since 2002, Terasen Gas has procured its customer care services including the call centre, meter reading, billing and collection activities through a Business Process Outsourcing ("BPO") agreement with CWLP, providing value to customers over the years. However, changes in the outsourcing services marketplace; changes in Terasen Gas' business environment driven by public policy on energy use and the environmental impacts; increased complexity of billing requirements; and evolving customer expectations necessitate that Terasen Gas review its customer care model and arrangement to ensure they provide the services required to meet the needs of customers going forward.

Areas under review include ensuring greater flexibility to respond to changes in the business environment, ensuring the Customer Information System application and hardware provide the functionality required, and having process ownership and accountability for key customer contact points, key business processes and supporting technologies. A CPCN application for this initiative was filed in June 2009.

(d) Advanced Metering Project

As a follow-up to the Customer Care Enhancement CPCN, Terasen Gas is assessing the value proposition associated with implementing Advanced Metering technology as an opportunity to provide customers with information to manage their energy consumption and to meet future meter reading requirements of Terasen Gas. The timing for filing of a CPCN application is dependent upon the results of the business requirements and technology evaluation.

(5) MAIN EXTENSION TEST

As presented in the "Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Main Extension Report for 2008 Year End" ("2008 Main Extension Report"), the main extensions installed in 2008 are economical and do not harm existing customers.[202]

Since January 1, 2008, both TGI and TGVI are required to meet an aggregate PI threshold of 1.1 for main extensions. The results presented in the 2008 Main Extension Report demonstrate that on a portfolio basis, the main extensions installed in 2008 are economical and do not harm existing customers because the average actual PI for TGI is 1.2, higher than the threshold of 1.1. Therefore, we believe no change is required to the main extension policy and the aggregate PI threshold of 1.1.

We will continue to provide an annual main extension report and if appropriate will propose changes to the main extension policy.

(6) CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)

The table below summarizes Terasen Gas' CIAC anticipated CIAC recoveries for 2010 – 2011.

Table C-9-12: Forecast Contributions in Aid of Construction[203]

	2009 Projection	2010 Forecast	2011 Forecast
Category A - Customer Additions	(3.2)	1.0	(0.7)
Category B - System Reliability & Integrity	(0.8)	(2.7)	(0.9)
Category C - IT and Non-IT	(2.6)	(2.0)	(2.0)
Category D - CPCN	-	-	-
Category F - Retirements	(0.2)	(0.3)	(0.3)
Total Nominal	**(6.7)**	**(4.0)**	**(3.9)**
Total Real	**(6.7)**	**(3.9)**	**(3.7)**
Average Customers	833,798	839,949	845,633
Total Nominal $/Customer	**(8.1)**	**(4.7)**	**(4.6)**
Total Real $/Customer	**(8.1)**	**(4.6)**	**(4.4)**

Note: Expenditures in $millions; Real totals in 2009 values

[202] See Appendix E-2 for a copy of 2008 Main Extension Report

[203] Total nominal per Part III, Section C, Tab 13, Schedules 52 and 53, Line 12, Column (4) less Gateway Project contribution amounts of $6.8 million in 2010 and $10.4 million in 2011 (Tab 13, Schedule 43, Line 5)

CIAC for 2010 and 2011 are based on recoveries for the projected customer additions and anticipated receivable work. Contributions of $4.0 and $3.9 million in 2010 and 2011 are anticipated to be lower than the average contributions of $8.1 million over the 2003 – 2008 period due to the elimination of the SLIF in 2008. Due to the PBR extension for 2008 - 2009, recognition of the SLIF elimination is being deferred until 2010 resulting in an understatement of CIAC in 2010.

Contributions for Category B are anticipated to be $2.7 and $0.9 million in 2010 and 2011. The recoveries in this category were budgeted based on historical levels of receivable work for Transmission crossing replacements and identified recoverable projects. Higher CIAC is anticipated in 2010 for an identified third party lateral relocation project at Logan Lake.

Contributions for Category C are anticipated to be $2.0 million in 2010 and 2011. The recoveries in this category were budgeted based on the anticipated receivable work for third party alterations.

(7) ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

The AFUDC rate is based on the Company's WACC. Therefore the allowance return is calculated by multiplying the project financing costs by the Company's WACC.

Table C-9-13: Forecast Allowance for Funds Used During Construction

	2009 Projection	2010 Forecast	2011 Forecast
Allowance for Funds Used During Construction	1.1	2.1	5.1
Total Nominal	**1.1**	**2.1**	**5.1**
Total Real	**1.1**	**2.0**	**4.9**

Note: Expenditures in $millions; Real totals in 2009 values

b) Summary

The proposed 2010 - 2011 capital budget reflects the appropriate level of capital expenditures needed to ensure the safety and reliability of the gas distribution system and provide service to new and existing customers. Terasen Gas believes the forecasted capital costs are prudent and required for Terasen Gas to meet the evolving needs of our customers and shareholder. Terasen Gas requests the approval of these capital expenditures.

10. Capital Structure

a) Introduction

Terasen Gas must be provided with an opportunity to earn a fair return on the capital employed in the Company's ongoing activities. The opportunity to earn a fair return is a fundamental component of the "regulatory compact" between the Company and customers, with customers obtaining the benefit of safe, reliable and cost-effective service. Presently, the deemed capital structure is 64.99 per cent debt and 35.01 per cent equity. On May 15, 2009 the Company filed its ROE and Capital Structure application ("ROE Application") with the Commission requesting an increase in the ROE to 11 per cent, and an increase to the deemed equity structure from the current 35.01 per cent to 40 per cent. Principally, the request to increase both the ROE and equity structure has been made so that the Company can continue to address the needs of its stakeholders. To do so it must continue to maintain the financial integrity necessary to access debt and equity markets for funding and provide investors and creditors with reasonable rates of return that are commensurate with the Company's risks relative to its utility peers and low risk industrial companies. If approved, the ROE would be effective July 1, 2009 and the capital structure of the Company will be adjusted with effect from January 1, 2010. The 2010 and 2011 revenue requirements included in this Application have been calculated using the currently approved equity thickness of 35.01 per cent and approved ROE of 8.47 per cent.

Debt consists of Long-term Debt and Unfunded Debt. The Company's long-term debt is public debt and is widely held by institutional investors. Unfunded Debt is primarily provided by way of issuance of commercial paper backed by a syndicated revolving credit facility provided by a group of major Canadian Banks. Terasen Gas is a wholly-owned subsidiary and receives its equity funding ultimately through Fortis.

b) Review of History Highlights (2003-2009 Actuals)

The Company has managed all its debt and equity financing activities throughout the PBR Period in a prudent and effective manner and since November 2005 in a manner consistent with the ring-fencing provisions imposed by the Commission. A summary of the long-term debt, unfunded debt and equity highlights from 2004 to 2009 are summarized below.

(1) LONG TERM DEBT

From the beginning of 2004 to the end of 2009 the Company has increased its long-term debt from $1,165.4 million to $1,504.3 million, an increase of $338.9 million or 29 per cent. It has raised $1,120 million through the issuance of medium term note debentures ("MTN" program). The maturities ranged from two years, with a floating rate coupon that reset quarterly, to thirty years, with coupons from 5.55 per cent (September 2006) to 6.55 per cent (February 2009). Over the same period, the Company repaid $781.1 million in maturing debt.

The Company issues its MTN Debentures under a Base Shelf Prospectus. The current Base Shelf Prospectus was established pursuant to Commission Order No. G-66-08 issued April 2008, and is valid for a period of 25 months, approving the issuance of up to $600 million of MTN Debentures. At the time of this filing, the Company has issued $350 million in debentures and is authorized to issue a further $250 million in debentures.

(2) UNFUNDED DEBT

The Company maintains a $500 million revolving credit facility to fund working capital, including gas supply inventory, and capital expenditures. Funding is normally obtained through commercial paper issuance with terms typically from one to three months. The average borrowing rates for each of 2004 to 2008 were 2.17 per cent, 2.78 per cent, 3.99 per cent, 4.70 per cent and 3.38 per cent, respectively. Terasen Gas, on average, will maintain unfunded debt in the range of 5 per cent to 15 per cent of total debt, although this will vary throughout the year. At December 31, 2008 the Company had short term debt outstanding of $239 million.

(3) EQUITY

From 2003 to 2009, equity has increased from $742 million to $859 million, reflecting both growing rate base and an increase in the deemed equity component of rate base.

After the acquisition by KMI in 2005, the Commission imposed a number of conditions intended to ring-fence the Company from its parent companies to preserve the integrity of its capital structure. These restrictions included a prohibition on the payment of dividends unless the Company has in place at least as much equity as that deemed by the Commission for rate-making purposes. The ring-fencing was reaffirmed after the acquisition by Fortis in 2007.

Effective January 1, 2006 by Order No. G-14-06, the Commission approved a change to the deemed equity component of the Company from 33 per cent to 35 per cent. Effective January 1, 2007 and approved by Commission Order No. G-160-06, the amalgamation of Terasen Gas (Squamish) Inc. (“TGS”) with Terasen Gas adjusted the deemed equity component to its currently approved level of 35.01 per cent.

c) *Long-Term Debt*

In this RRA, the Company has projected an issue of $100 million in MTN Debentures in December of 2009 and a further $100 million in 2011 to fund rate base additions over the next 2 year period. The amount is set out in Part III, Section C, Tab 13, Schedule 66.

d) *Unfunded Debt*

The Company obtains short term funding primarily through the issuance of commercial paper to Canadian institutional investors. The Company backstops the issuance of commercial paper by maintaining a $500 million committed credit facility, which provides the Company with crucial liquidity should there be constraints in the capital markets that make obtaining cost-effective financing for its working capital and debt issuance requirements temporarily unavailable.

The recent financial crisis clearly highlights the importance of the current committed credit facility. In the fall of 2008, the global credit crisis effectively restricted both short and long term issuance in the Capital Markets for an extended period of time. The Company was able to fund through its committed credit facility during this period, until a return to more normal market access. The fallout from the crisis has resulted in the failure of several financial institutions. This has contributed to a restriction of available lenders in the Canadian bank market and has led to a tightening in the supply of bank credit facilities. The Company was proactive in extending its credit facility to 2013, positioning it well to manage through market disruptions during this period of economic uncertainty.

e) *Equity*

The Company maintains a 35.01 per cent equity structure as deemed by the Commission for rate-making purposes. Its equity structure is typically maintained by making adjustments through the amount of dividends declared to its parent company on an annual basis. These adjustments reflect the equity related portion of additions to rate base.

In the May 15, 2009 ROE Application submitted to the Commission, the Company is seeking a change to the Benchmark ROE and its capital structure.

f) *Forecast of Relevant Interest Rates for 2010 - 2011*

The Company uses independent interest rate forecasts to determine its future interest expense. The rates used for short-term and long-term debt are averages of individual rate forecasts from leading economists. The economists are independent, and are from Canadian chartered banks and the Conference Board of Canada.

Due to the global credit crisis in the fall of 2008, the Bank of Canada ("BOC") has decreased the overnight rate to historic lows, consistent with the monetary policy of the United States and other G20 countries in Europe and Asia. The current overnight rate is 0.25 per cent. It and all other short-term rates that use the overnight rate as a proxy (i.e. Prime bank lending rate) are expected to remain at low levels for the next 12-18 months. It is not anticipated that there will be a full economic recovery prior to 2011. Short term rates are not expected to return to recent historical averages until the economic recovery takes hold.

Surveys of leading economists expect the Prime bank lending rate to remain on average at 2.5 per cent for 2009, and then increase to 6.0 per cent by 2012. In arriving at the Company's short-term borrowing rate forecast for 2010 and 2011, the Company has considered its historical short-term borrowing differential between the Prime bank lending rate and the rate issued under the commercial paper program at that time. Over the last 12 months, the Company's commercial paper has been issued at an average of 1.61 per cent below the Prime bank lending rate. To be conservative the Company has used a lower rate differential of 1.25 per cent in its projections, which it believes is appropriate given the current low interest rate environment.

Table C-10-1: Determination of short-term interest rates for 2010 and 2011

	2010	**2011**
Prime Rate	3.50%	5.75%
Short-Term Debt Rate Spread	-1.25%	-1.25%
Short-Term Debt Rate	**2.25%**	**4.50%**

The Company is forecasting the cost of fixed-rate, long-term borrowing on new debt to be in the range of 6 per cent to 7 per cent over the 2010-2011 period. Given the Company's new MTN issues from 2004 to 2009 were funded at rates between 5.55 per cent and 6.55 per cent, the higher predicted range is an appropriate estimate in the current economic environment. The higher forecasted cost of debt is a result of the Company's credit spreads remaining wider than recent historical averages, resulting in an overall increase in rates on new issues during this period.

g) Interest Expense Forecast

The following table highlights long-term and short-term interest expense for 2010 and 2011:

Table C-10-2: Terasen Gas Interest Expense 2010 & 2011 Forecast ($000's)[204]

	2010	2011
Long Term	108,533	112,204
Short Term	1,521	3,226
Total Interest Expense	110,054	115,430

The interest expense reflects the Company's projected new issues, projected borrowing costs on new issues and short-term interest rates.

h) Allowed Return on Equity

The ROE and the return associated with debt comprise the earned return component of the cost of service and correspondingly, have a direct impact on the revenue requirement.

The 2010 and 2011 revenue requirements have been calculated using the currently approved equity thickness of 35.01 per cent (Commission Order No. G-160-06) and approved ROE of 8.47 per cent (Commission Order No. L-55-08). Both the equity thickness and ROE are subject to change and are dependent on the outcome of the recently filed ROE Application. Adjustments to the equity thickness and ROE will result in changes to the revenue requirement and to delivery rates in each forecast year that are different than those proposed in this Application.

The ROE Application requests the Commission abandon the ROE formula and establish a new Benchmark ROE as well as an increase to the deemed equity in the capital structure. The approval of the ROE Application as filed would result in equity thickness and ROE rates as presented in the table below and an impact to the cost of service of approximately $49.2 million in 2010 and approximately $46.0 million in 2011:

Table C-10-3: ROE Application Proposal

	2010	2011
Return on Equity per cent	11 per cent	11 per cent
Equity Thickness	40 per cent	40 per cent

[204] Section C, Tab 13, Financial Schedules 62 & 63

The 2010 and 2011 rate proposals will be revised to reflect the outcome of the ROE Application, when the Decision is issued.

i) Summary

The Company continues to prudently manage its capital structure and address its financing requirements, to meet the needs of its various stakeholders. The Company maintains adequate credit facilities to provide sufficient liquidity to meet its ongoing working capital requirements and address any concerns that may result from tighter credit markets and the global recession. The Company is an active participant in the debt capital markets and has fostered strong relationships with its lenders. It has taken a reasoned and prudent approach to funding its long term debt requirements. Through the ROE Application, the Company is seeking a higher deemed equity structure and a new and higher Benchmark ROE. The higher equity component and greater return on equity will better align the risk and return profile of the Company and its stakeholders.

11. Accounting and Other Policies

Accounting and other policies adopted by Terasen Gas, such as depreciation studies and rates, levels of capitalized overheads, corporate and shared services agreements, and transfer pricing policies, have a significant impact on the timing and amount of costs and revenues included in this RRA. The policies described in the following sections reflect the most appropriate methodologies for cost recovery in 2010 and 2011, while incorporating the latest updates from accounting standard setting bodies, and considering general principles of regulatory cost allocation. As displayed in the following table, the impact of all of these accounting changes on our revenue requirements is significant in 2010, as we move to adopt IFRS-compliant policies.

Table C-11-1: Accounting Changes Impact our Revenue Requirements (amounts in $ millions)

		2010 Increase/(Decrease) over 2009			
Ref	Description	O&M	Dep'n	PP&E	Rev Req
b-1	Training costs previously capitalized	$ 2.2	$ (0.1)	$ (2.1)	$ 2.0
b-1	Feasibility studies previously capitalized	0.5	(0.0)	(0.5)	0.5
c-4.4	Capitalization of current service portion of pension and OPEBs	(1.7)	0.0	1.7	(1.6)
c-7	Inspection costs now capitalized	(1.3)	0.0	1.3	(1.2)
c-7	Commencement of depreciation		1.9	(1.9)	2.6
d	Depreciation study impacts		20.8	(20.8)	28.5
e	Reduction in overhead capitalized	11.2	(0.2)	(11.0)	10.6
f	Shared services with TGVI	(2.9)			(2.9)
h	Corporate services with Terasen Inc	0.5			0.5
		$ 8.5	$ 22.5	$ (33.4)	$ 39.0

		2011 Increase/(Decrease) over 2010			
Ref	Description	O&M	Dep'n	PP&E	Rev Req
c-9.1	2011 Pension and employee future benefits - annual expense	$ (2.0)		$ (1.4)	$ (2.0)
d	Depreciation study impacts		0.4	(0.4)	0.5
f	Shared services with TGVI	(0.4)			(0.4)
h	Corporate services with Terasen Inc	0.1			0.1
		$ (2.3)	$ 0.4	$ (1.8)	$ (1.7)

a) Canadian Generally Accepted Accounting Principles

Terasen Gas reviews changes to Canadian GAAP each year for implications on internal accounting procedures, published financial statements, and regulatory accounting records. The two changes to Canadian GAAP that are of relevance for regulatory accounting records and that were effective January 1, 2009 have been reflected in this RRA.

(1) SECTION 3064 GOODWILL AND INTANGIBLE ASSETS

Section 3064, Goodwill and Intangible Assets, which replaces Section 3062, Goodwill and Other Intangible Assets, and Section 3450, Research and Development Costs, establishes standards for the recognition, measurement and disclosure of goodwill and other intangible assets. The new standard is essentially the same as International Accounting Standard 38, Intangible Assets. As a result of adopting this standard, the Company has reclassified the net book value of land and transmission rights, certain computer software costs and franchise costs from PPE to Intangibles in its published financial statements. For regulatory purposes, these amounts continue to be shown as PPE, but have been shown as a separate section on the Plant and Accumulated Depreciation Continuity Schedules (Part III, Section C, Tab 13 Schedules 44, 46, 48, 50). Another requirement of Section 3064 is that training costs and feasibility study costs that had previously been capitalized, are no longer permitted to be capitalized. For 2009 Terasen Gas has continued to account for these as capital consistent with their treatment under the PBR Period. Terasen Gas is proposing to expense these training and feasibility study costs starting in 2010 for revenue requirement purposes.

(2) RATE REGULATED OPERATIONS

Effective January 1, 2009, the Accounting Standards Board amended:

> (i) CICA Handbook Section 1100, Generally Accepted Accounted Accounting Principles, removing the temporary exemption for rate-regulated entities from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation; and
>
> (ii) Section 3465, Income Taxes, to require the recognition of future income tax liabilities for rate regulated entities, as well as permitting the recognition of an offsetting regulated asset for amounts expected to be included in approved rates charged to customers in the future.

With the removal of the temporary exemption from Section 1100, although some assets and liabilities arising from rate regulation continue to have specific guidance under the CICA Handbook, for those that do not, Section 1100 directs the Company to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Section 1000, Financial Statement Concepts. The Company's regulatory assets and liabilities qualify for recognition as assets and liabilities under Section 1000. Therefore, there has been no effect on the Company's financial statements due to the removal of the temporary exemption.

The adoption of the changes to Section 3465 Income Taxes has resulted in the inclusion in rate base of both a future income tax liability and an equal and offsetting amount for a regulatory future income tax asset.

Terasen Gas does not anticipate any other changes to Canadian accounting standards that would impact regulatory accounting records prior to adoption of International Financial Reporting Standards.

b) International Financial Reporting Standards

Terasen Gas' financial records are maintained in accordance with GAAP and are audited by an independent public accounting firm. As GAAP moves from Canadian standards to IFRS we must meet the requirements of the new standards.

There are several reasons why it is critical that Terasen Gas adopt IFRS for both financial and regulatory reporting purposes.

- To reduce the costly administrative burden of reconciling differences between the financial reporting results under IFRS and the regulatory reporting results. Some of these costs would be incurred on a one-time basis (development of parallel ledgers) and others would be ongoing in nature (staffing levels and IT maintenance costs), with the ongoing compliance costs increasing as the complexity of the reconciliation process escalates over time.
- To reduce the costs for additional audit and verification required when the amounts that are recorded for regulatory purposes are not captured in the audited financial statements.
- To improve transparency by harmonizing the results presented to the Commission and customer representatives with the results presented to shareholders and investors, and thereby achieve a better balance of the interests of all stakeholders. Additional material required for presentation to investors to aid in understanding of the economic impacts of rate regulation will come at an additional cost.

Terasen Gas recognizes the need to balance the above goals with the requirement to avoid volatile rate impacts. Where harmonization of regulatory accounting with IFRS has significant impacts to customers, an appropriate mechanism to deal with those impacts would be through the continued use of deferral accounts. Therefore, the Company proposes to implement deferral accounts where appropriate, and also to limit all regulatory and IFRS differences to those that can be captured and tracked in deferral accounts for the following reasons.

- An IFRS exposure draft on Rate-regulated Activities is expected to be published in July 2009. Indications are that this exposure draft will permit the recognition of regulatory deferral accounts in IFRS compliant financial statements under certain circumstances. However, it is uncertain if this recognition principle will be extended to regulatory amounts embedded in accounts other than deferrals.
- There is an expectation that the exposure draft will require that a "two-step" approach be taken in recognizing the effects of rate regulation, where items would be first recorded according to IFRS, and then as a second step adjusted for the effects of rate regulation. Confining rate impacts to deferral accounts will simplify this second step.
- Should the exposure draft not be accepted as a standard, holding all regulatory to IFRS differences in deferral accounts will allow all of the other underlying records of the Company's assets to be consistent for both rate-setting and financial reporting purposes, and minimize the work required to reconcile the IFRS compliant financial statements to the regulatory accounting records.

(1) BACKGROUND

IFRS adoption will be required for Terasen Gas effective January 1, 2011, with comparative amounts for 2010 restated to be compliant with IFRS, and transitional adjustments for items in accordance with IFRS 1 - First Time Adoption of IFRS. Therefore, the proposed impacts of the various standards on the Revenue Requirements Application are the following:

- The 2011 IFRS cost of service impacts which are recovered through rates in 2011;
- The 2010 IFRS cost of service impacts, which can either be recovered through rates in 2010 or deferred and recovered through future rates; and
- The IRS transitional adjustments which are deferred and recovered through future rates.

Where the IFRS changes are compliant with Canadian GAAP, Terasen Gas proposes to recover the 2010 impacts in 2010. Where the IFRS changes are not compliant with Canadian GAAP, Terasen Gas proposes to record the 2010 impacts as transitional adjustments and recover them through future rates. With the exception of the IFRS conversion costs and any ongoing reconciliation and audit requirements, the changes from Canadian GAAP to IFRS do not affect total costs to be recovered from ratepayers; but absent the potential mitigating effect of deferral accounts, the standards do change the timing of when those costs would be recovered.

The following sections summarize Terasen Gas' approach to each of the IFRS changes that are expected to affect revenue requirements. This section should be read in conjunction with the document "International Financial Reporting Standards (IFRS): A Summary of Anticipated Impacts of Transition to IFRS on Rate Regulated Utilities in British Columbia", included as Appendix H-1. For ease of reference, the numbering of sections below is consistent with that document.

(2) REGULATORY ASSETS AND LIABILITIES (DEFERRAL ACCOUNTS) UNDER IFRS

Terasen Gas proposes to continue recording items in deferral and variance accounts where those items have the potential to be a material amount, and where the variances are largely determined by influences outside the control of the Company. See Part III, Section C, Tab 8 Rate Base for a listing and description of proposed deferral accounts.

Terasen Gas will continue to monitor the status of the Exposure Draft on Rate-Regulated Activities, and will reflect any impacts of changes between the expected and final versions in an IFRS Transitional Deferral Account, also described in Part III, Section C, Tab 8 Rate Base.

(3) PROPERTY, PLANT AND EQUIPMENT - VALUATION

3.1 Initial Adoption of IFRS

To continue to achieve consistency between IFRS and regulatory records, and since the historical carrying value as recognized by the BCUC represents the economic value of the assets, we will elect to use the proposed IFRS 1 exemption which will allow us to use historical carrying value as the opening PPE balance as of January 1, 2010.

There are two uncertainties around the IFRS 1 proposed exemption as currently drafted:

- in order to elect historical cost, the current wording requires that it be "impracticable" to determine fair value or restate historical cost; and
- the IFRS 1 exemption as written does not extend to intangible assets that had previously been classified as PPE under Canadian GAAP (primarily computer software and land rights).

Recent discussions of the IASB indicate that both of these issues should be resolved with the final form of the IFRS 1 exemption.

Although we do not anticipate any retained earnings adjustments to result from the initial adoption of IFRS as it relates to PP&E, any unanticipated adjustments would be captured in the IFRS Transitional Deferral Account.

3.2 After Transition to IFRS

After transition to IFRS, Terasen Gas proposes to continue recording its PP&E at historical cost less accumulated depreciation. This is unchanged from current practice.

(4) PROPERTY, PLANT AND EQUIPMENT - CAPITALIZATION POLICIES

Terasen Gas proposes to capitalize costs in accordance with IFRS, which will overall result in a reduced amount of costs being capitalized.

4.1 Overheads capitalized

Terasen Gas proposes to reduce the amount of overheads capitalized to reflect only costs that meet the definition of "directly attributable", and that exclude administrative and general overhead. See a complete discussion of the overheads capitalized on page 489.

4.2 Capitalization of borrowing costs

Terasen Gas proposes to continue to capitalize AFUDC on assets that take a substantial period of time to get ready for use. We expect this to be an acceptable practice under the anticipated Exposure Draft on Rate-Regulated Activities.

4.3 Capitalization of depreciation on assets used in construction

Terasen Gas proposes to capitalize depreciation on those assets, such as backhoes and other heavy duty equipment, used in construction of utility assets, as part of the cost of constructing those assets. This item does not result in any change for Terasen Gas, since capitalization of depreciation on vehicles has always been captured as part of the labour loading rates.

4.4 Capitalization of the current service cost component of pensions and employee future benefits

Terasen Gas proposes to continue to capitalize an appropriate portion of the current service component of pension expense, and additionally to capitalize an appropriate portion of the current service component of other employee future benefits, by including these costs in labour rates that are directly charged to capital. Currently the full amount of OPEB costs are being expensed.

The net impact of these four changes is an increase in O&M and a corresponding decrease in capital (rate base). The result is that net rates will rise in the short term as costs that have traditionally been borne by ratepayers over the life of the asset would now be borne entirely in the year they are incurred. This initial rise in rates will be offset by subsequent reductions in rates as a result of lower depreciation charges, return on rate base and taxes in later years.

(5) PROPERTY, PLANT AND EQUIPMENT - OTHER ITEMS

5.1 Gains and losses on disposal of assets

Due to the significant uncertainty around whether IFRS will allow gains and losses on disposal of assets to follow current regulatory practice of being charged to accumulated depreciation instead of being immediately taken into income, Terasen Gas proposes to record gains and losses on disposition or retirement of PP&E in 2010 and 2011 in a deferral account for disposition as part of the next revenue requirements application. This will maintain a consistent rate base treatment for these items with the current practice.

5.2 Customer contributions

Terasen Gas proposes to continue its current treatment of customer contributions (contributions in aid of construction) as a credit to rate base, and amortization of the contributions recognized as a reduction in depreciation expense over the life of the asset. Terasen Gas considers this to be the appropriate period over which to recognize the contributions under the IFRS guidelines. The resulting classification differences (credit to rate base versus a liability, and depreciation offset versus revenue) will be a reconciling item between financial statement classification and regulatory accounting classification.

5.3 Asset Retirement Obligations

Terasen Gas does not believe it has any material asset retirement obligations that will be required to be recognized under IFRS. The Company is of the view that a constructive obligation may exist with respect to decommissioning costs that will be incurred when a major portion of our network may reach the end of its useful life. We may therefore be required to recognize that obligation as a provision on our balance sheet in accordance with International Accounting Standard 37 when we have an estimate of when a major portion of our network may reach the end of its useful life. However, because our network is essentially operated in perpetuity, the date upon which it will be taken out of service is generally not determinable. Therefore the present value of that obligation will be immaterial.

In the case of interim component replacements made over the course of our network's useful life, the cost of removing and replacing these components does not represent a provision to be recognized in accordance with International Accounting Standard 37. The Company is of the position that these costs should be capitalized which is consistent with past practice at Terasen Gas.

The Company collects non-ARO costs related to removal and decommissioning from current customers for future removal of today's assets, as these amounts represent costs of operating the system today. These estimates are currently being recovered as a component of depreciation rates. Terasen Gas proposes to continue this recovery methodology as well as the current regulatory classification as a component of accumulated depreciation. For financial statements purposes, the Company will classify these amounts as a regulatory liability against which future removal costs will be charged.

(6) PROVISIONS, LEGAL AND CONSTRUCTIVE OBLIGATIONS

Terasen Gas includes a working capital allowance in rate base, calculated according to accepted regulatory practices. The Company does not anticipate that the IFRS standard on provisions, legal and constructive obligations will have an impact on its working capital or rate base calculations.

(7) DEPRECIATION

IFRS requirements are largely the same as current GAAP requirements, with the following exceptions:

- IFRS specifically requires that depreciation of assets commences when the asset is available for use;
- Accounting for components is more rigorously followed under IFRS. To the extent asset classes include components with different lives that would materially impact depreciation, these components must be separately depreciated; and
- IFRS recognizes both physical and non-physical components, with the result that the costs of major overhauls or inspections embodied in an asset need to be split out and depreciated over a shorter life than the actual physical asset.

Terasen Gas has engaged Gannett Fleming, Inc. to conduct a depreciation study of its assets, incorporating the anticipated requirements of IFRS. See the discussion on the depreciation study and the recommended depreciation rates on page 484.

Terasen Gas proposes to incorporate the results of this depreciation study in this RRA, and as a result adopt IFRS as it relates to depreciation expense. This includes:

- Recognizing that depreciation expense commences when assets are available for use, instead of at the beginning of the following year as is the current practice;

- Creating new asset sub-classes for major overhauls and inspections, with separate depreciation rates;
- Continuing the use of the Average Service Life for those asset classes where group depreciation methods are deemed appropriate;
- Using the amortization accounting method for those general plant categories where this method is acceptable; and
- Recognizing the accounting impacts of the disposal of individual assets where reasonable and appropriate.

Terasen Gas seeks approval to change depreciation methodology and rates, to reflect the new IFRS reporting standards.

(8) INCOME TAXES

Currently, Terasen Gas uses the taxes payable (flow-through) method to calculate income tax for regulatory purposes. In accordance with Canadian GAAP, a future income tax liability and offsetting regulatory future income tax asset is also recognized.

Depending on the outcome of the proposed IASB exposure draft on Rate-regulated Activities, to the extent this resulting asset meets the recognition criteria under the new standard, the current treatment would continue.

For purposes of this RRA, Terasen Gas has assumed that the current treatment would be acceptable under IFRS, and proposes to record in rate base both the Future Income Tax Liability compliant with both Canadian GAAP and IFRS, and an offsetting Regulated Future Income Tax asset according to Canadian GAAP. Once the exposure draft for Rate-regulated Accounting is released, Terasen Gas will consider whether an application to the BCUC is appropriate to reflect a revised approach.

(9) PENSION AND EMPLOYEE FUTURE BENEFIT COSTS

9.1 Initial Adoption of IFRS

Terasen Gas proposes to recognize all cumulative actuarial gains and losses on transition, and proposes to defer the retained earnings impact of this change in its IFRS Transitional Deferral Account. The January 1, 2011 amount estimated by our actuaries at December 31, 2008 and included in this RRA related to the initial adoption of IFRS for pension and employee future benefit costs, is a retained earnings charge of $57.7 million. Regulatory deferral treatment of this amount will neutralize the otherwise negative impacts of this retained earnings adjustment on Terasen Gas' shareholder, on related debt covenants and on the Company's ability to pay out dividends. Since the offsetting entry to this charge is a credit to the unfunded pension and other post retirement benefits liability (pension and OPEB deferral), which is also included in rate base, there is no impact of this entry on customer rates in 2011.

9.2 Actuarial gains and losses

For purposes of this RRA, Terasen Gas is proposing to continue to amortize these amounts to income using the corridor method. Although the final decision on the method chosen will not be determined until sometime in 2010, Terasen Gas does not forecast future actuarial gains and losses to occur, so the choice of method would not impact what has been included in this RRA related to actuarial gains and losses.

9.3 Past service costs

Terasen Gas proposes to recognize past service costs in accordance with IFRS, which will generally result in immediate recognition since past service costs would already have vested.

9.4 Return on plan assets

For pension accounting, Terasen currently utilizes market related fair values which result in a smoothing of assets over a three year period. The smoothing of the fair value of pension assets also results in a smoothing of the pension expense especially during time of significant volatility in market returns. As a result of the adoption of IFRS, the Company can no longer utilize market related fair values and is required to recognized a one time charge as a result of the change from market related value of assets to fair values. Terasen Gas proposes to defer this adjustment and recover it from customers along with the amount resulting from initial adoption of IFRS in the IFRS Transitional Deferral Account.

9.5 Summary of Pension and Employee Future Benefit Changes

Terasen Gas proposes to continue to estimate pension and employee future benefit costs as per actuarial assumptions, and include those costs in revenue requirements. Where significant fluctuations in expenses occur from those that have been anticipated, the Company proposes to defer those amounts.

(10) LEASES

While the IFRS standard on Leases (IAS 17) is very similar to the current Canadian standard, a pending change to the standard will result in substantially all leases being treated as capital from the lessee's perspective. Given this pending change, and the goal of minimizing differences between financial and regulatory records under IFRS in the area of PP&E, Terasen Gas is proposing to harmonize the treatment of the vehicle lease as capital for both financial and regulatory purposes. The vehicle lease will continue to be treated as an operating lease for regulatory income tax calculation purposes. The result of this change is that the vehicle lease is removed from operating expenses. The net book value of the leased assets is added to PPE with depreciation being calculated annually, and the capital lease liability is included in long-term debt with associated interest expense. The impact of the accounting change to rates is immaterial at less 0.1 per cent in 2010.

We will continue to monitor the status of IFRS and the implications of any new or revised pronouncements on our Revenue Requirement Application.

c) Depreciation Study and Rates

As outlined in previous years' applications, Terasen Gas has identified the need for changes to its existing depreciation rates. Since the previous Commission decision in 2003 which approved depreciation rate changes to a few asset classes, Terasen Gas has completed another depreciation study of its utility rate base assets. This practice of periodically reviewing and updating depreciation lives ensures that the depreciation rates are appropriate. Reviewing depreciation rates on a regular basis is a requirement of the new IFRS standards.

Terasen Gas considers the results of the recent study as being reasonable and representative of the asset service life profiles for the Company, and will also enable the Company to comply with new IFRS requirements. The study has been prepared by Gannett Fleming Valuation and Rate Consultants Inc. ("Gannett Fleming"), a leading Depreciation, Valuation and Ratemaking consulting firm in North America. The results in comparison to the prior study are consistent, highlighting the ongoing differences between the Company's actual historical depreciation rates and those that are being recommended in the current study.

Terasen Gas proposes the adoption of the recommended depreciation rates effective January 1, 2010, as outlined in the current study, appropriately allocating the consumption of the asset's useful lives over time and incorporating the requirements of IFRS.

(1) OVERVIEW

In 2000, a similar depreciation study prepared by Gannett Fleming in 1998 was reviewed with Commission staff, with a summary of the study circulated to interested parties. A proposal for increases in some depreciation rates was included in the Annual Review of November 2000, but because of large commodity-related rate increases at that time, the proposal was not implemented. In its 2004 – 2008 multi-year PBR Application, Terasen Gas sought and received Commission approval through Commission Order No. G-51-03 to implement the depreciation rate changes for some asset classes, specifically Meters, Meter Installations and Regulators, and Computer Software.

Terasen Gas recently retained Gannett Fleming again to conduct a depreciation study of its utility rate base assets. The study which is included in Appendix H-2 has been prepared based on gas plant-in-service as of December 31, 2007 for Terasen Gas' utility assets. Terasen Gas considers that the study results continue to be applicable for the 2010 and 2011 forecast period as Gannett Fleming estimates the rates calculated in the depreciation study are reasonable for a period of three to five years. Terasen Gas has internally updated the plant balances in the depreciation study and recalculated the revenue requirement impacts of implementing the study.

Gannett Fleming has estimated the depreciation rates using various statistical methods and informed judgment based on their extensive experience in the natural gas industry. Straight-line depreciation is developed for the assets in a particular class beginning with the original cost, the estimated average and remaining service life characteristics and then accounting for the accumulated depreciation already booked in that class and the applicable net salvage costs.

(2) HIGHLIGHTS

Overall, Gannett Fleming's recent study results are consistent with the prior year's study, highlighting that Terasen Gas' depreciation rates need to be increased. Gannett Fleming advises that overall, in their view, the largest factor driving the proposed changes in depreciation rates is the continued use of the pre-1998 depreciation rates. Gannett Fleming recommends that the depreciation rates as outlined in the refreshed depreciation study be implemented in order to reverse the trend of the growing accumulated depreciation deficiency that exists in most of the accounts.

The categories that account for the majority of the expected increase in depreciation expense are Distribution Mains, Meters, Meter Installation and Regulators and Distribution Services, with the Distribution Services category accounting for nearly half of the expected increase. Distribution Services plant represents approximately 20 per cent of Terasen Gas' depreciable plant.

In determining the projected depreciation rate for Distribution Services plant, Gannett Fleming analyzed the retirements, additions and other plant transactions for the period 1959 through 2007, conducted interviews with Terasen Gas operating and engineering staff, and compared Terasen Gas' retirement records to other industry peers. The retirement analysis indicates a significant rate of retirement activity as the Distribution plant reaches 45 years of age, with large retirements through to age 70. To date, over $44 million of retirement activity has been experienced. The recommended depreciation rate including the Service Life and Net Salvage components for Distribution Services plant is 3.3 per cent compared to the current depreciation rate of 2.00 per cent as indicated on line 25 in Table C-11-2 below.

(3) IMPLEMENTATION OF RECOMMENDATIONS

Implementation of the recommended rates, which are set out in Table C-11-2 below, that were developed using the Average Service Life ("ASL") depreciation methodology and are expected to be compliant with IFRS requirements, would increase the average composite depreciation rate for Terasen Gas plant from approximately 2.7 per cent to 3.4 per cent [refer to line 62 of Table C-11-2], with the annual depreciation expense increasing by approximately $21 million. Since depreciation expense is not tax deductible, the Company's revenue requirement increases by approximately $29 million. This excludes the effects on depreciation expense of additions to PP&E, the proposed IFRS changes related to the commencement of depreciation and differences in classification of items as capital or expense, discussed earlier in on page 485 under Depreciation. For a summary of the total revenue requirement impact of depreciation changes see Part III, Section C, Tab 2, Revenue Requirements, Table C-2-1.

Table C-11-2: Impact of Implementing Recommended Depreciation Rates

Line #	Class	Description	Current Rate	Recommended Depreciation Rate	Depreciation Based on Current Rate	Depreciation Based on Recommended Rate	Increase + / Decrease -
	NATURAL GAS & PETROLEUM PIPELINE SYSTEMS						
1	40100	Franchises and Consents	1.00%	19.76%	992	19,609	18,617
2	40200	Intangible Plant	1.00%	2.14%	6,876	14,714	7,838
3	40210	Plant Acquisitions and Adjustments	1.00%	23.66%	625	14,777	14,152
4	43200	Mfg. Gas Structures	1.50%	3.28%	7,117	15,561	8,444
5	43300	Mfg. Gas Equipment	3.00%	6.30%	12,658	26,582	13,924
6	43400	Mfg. Gas Holders	2.00%	3.90%	13,195	25,730	12,535
7	43600	Mfg. Gas Compressor Equipement	3.00%	4.96%	1,599	2,644	1,045
8	43700	Mfg. Gas Meas/Reg Equipment	3.00%	19.50%	9,283	60,342	51,059
9	44200	LNG Gas Structures	4.00%	4.02%	195,383	196,360	977
10	44300	LNG Gas Equipment	4.00%	2.61%	666,133	434,652	- 231,481
11	44900	LNG Gas Other Equipment	4.00%	3.70%	935,696	865,519	- 70,177
12	46200	TP Compressor Structures	3.00%	4.03%	440,702	592,009	151,307
13	46300	TP Meas/Reg Structures	3.00%	4.48%	148,441	221,672	73,231
14	46400	TP Other Structures	3.00%	3.02%	178,759	179,950	1,191
15	46500	TP Transmission Pipeline	2.00%	1.79%	15,270,551	13,667,143	- 1,603,408
16	46510	TP Transmission Pipeline - Byron Creek	5.00%	5.00%	46,579	46,579	-
17	46600	TP Compressor Equipment	3.00%	3.50%	3,329,658	3,884,601	554,943
18	46710	TP Meas/Reg Equipment	3.00%	7.55%	882,192	2,220,182	1,337,990
19	46720	TP Telemetry Equipment	10.00%	1.33%	846,904	112,638	- 734,266
20	46730	TP Measurement/Regulator Equipment	3.00%	4.21%	1,161	1,630	469
21	46800	TP Communications Equipment	10.00%	5.32%	34,589	18,401	- 16,188
22	47200	DS Structures	3.00%	3.78%	440,886	555,517	114,631
23	47210	DS Structures - Byron Creek	5.00%	5.00%	5,362	5,362	-
24	47300	DS Services	2.00%	3.38%	12,838,744	21,697,478	8,858,734
25	47301	LILO DS Services	2.00%	3.30%	864,582	1,426,561	561,979
26	47400	DS Meters/Regulators Installations	3.57%	5.21%	4,797,021	7,000,695	2,203,674
27	47401	LILO DS Meters/Regulators Installations	3.57%	2.19%	573,704	351,936	- 221,768
28	47500	DS Mains	2.00%	2.26%	16,901,151	19,098,300	2,197,149
29	47501	LILO DS Mains	2.00%	2.40%	794,087	952,905	158,818
30	47600	DS NGV Fuel Equipment	6.67%	25.04%	38,076	142,943	104,867
31	47710	DS Meas/Reg Additions	3.00%	5.72%	2,474,212	4,717,497	2,243,285
32	47720	DS Telemetry	10.00%	0.25%	591,343	14,784	- 576,559
33	47730	DS Meas/Reg Equipment	5.00%	0.00%	8,158	-	- 8,158
34	47810	DS Meters	3.57%	5.31%	6,598,042	9,813,895	3,215,853
35	47811	LILO DS Meters	3.57%	3.29%	357,954	329,879	- 28,075
36	47820	DS Instruments	3.57%	4.03%	401,674	453,430	51,756
37	17500	Unamortized Conversion/Expense	1.00%	1.00%	78,790	78,790	-
38	17800	Organizational Costs	1.00%	1.00%	7,281	7,281	-
39					70,800,160	89,268,548	18,468,388
40							
41	**PLANT, BUILDING AND EQUIPMENT**						
42	48210	GP (Frame) Structures	3.00%	3.67%	158,584	194,001	35,417
43	48220	GP (Masonry) Structures	1.50%	4.37%	1,252,911	3,650,147	2,397,236
44	48230	GP (Leased) Structures	10.00%	0.00%	47,340	-	- 47,340
45	48310	GP Computer Hardware	20.00%	20.00%	3,643,752	3,643,752	-
46	40201	Application Software - 8 yr life	12.50%	12.50%	6,953,519	6,953,519	-
47	40202	Application Software - 5 yr life	20.00%	20.00%	1,610,241	1,610,241	-
48	48320	GP Computer Software	20.00%	20.00%	170,765	170,765	-
49	48330	GP Office Equipment	5.00%	6.67%	224,040	298,869	74,829
50	48340	GP Furniture	5.00%	5.00%	986,465	986,465	-
51	48400	GP Vehicles	15.00%	6.16%	341,847	140,385	- 201,462
52	48510	GP Heavy Work Equipment	5.00%	5.65%	10,438	11,795	1,357
53	48520	GP Heavy Mobile Equipment	5.00%	6.43%	28,052	36,075	8,023
54	48600	GP Small Tools/Equipment	5.00%	5.00%	1,608,902	1,608,902	-
55	48720	GP NGV Cylinders	10.00%	6.67%	2,417	1,612	- 805
56	48810	GP Telephone Equipment	5.00%	6.67%	561,978	749,679	187,701
57	48820	GP Radio Equipment	10.00%	6.67%	489,515	326,506	- 163,009
58					18,090,766	20,382,713	2,291,947
59							
60			Total Annual Depreciation		88,890,926	109,651,261	20,760,335
61							
62			Annual Composite Rate		2.7%	3.4%	
63							
64	* Numbers above are in actual dollars with depreciation calculated using the January 1, 2010 gross asset values.						

Of the 3.4 per cent composite depreciation rate, 3.0 per cent is related to the life of the assets whereas 0.4 per cent is for depreciation related to negative net salvage value. Net salvage value is considered to be the proceeds received for property retired less any expenses incurred in connection with the sale or removal of the asset, or preparing the asset for sale. When the removal expenses are greater than the proceeds, it is referred to as negative net salvage value. Consistent with the previous study, the recommended depreciation rates were developed using an estimate of average service life and net salvage values.

In the ASL procedure, the rate of annual depreciation is based on the average life or average service life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

An alternative depreciation methodology for adoption is the Equal Life Group ("ELG"). In the ELG procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life group. For purposes of determining an annual rate, the calculated depreciation amount is divided by the surviving balance of the group's cost.

Both methods allocate the cost of the assets to the pattern of consumption by the utility's customers. The ELG method provides a more detailed breakdown of the components within each asset class and as such provides a much more detailed estimate of the depreciation. If the ELG method were adopted, the depreciation expense would be approximately $15 million higher than that calculated using the ASL. From Terasen Gas' perspective, both depreciation methods are acceptable. Terasen Gas proposes the continuation of the ASL approach as it believes the ASL approach complies with IFRS requirements and helps to mitigate customer rate impact.

Terasen Gas believes the adoption of the depreciation rates as outlined in the most recent depreciation study is necessary in order to reverse the trend of the growing accumulated depreciation deficiency that exists, and that results in an unfair allocation and recovery of depreciation expense between current and future ratepayers. In addition, adoption of depreciation rates that reflect current useful lives will be required for Terasen Gas to be in compliance with IFRS requirements.

For some specific categories of general plant which do not lend themselves well to mass asset accounting practices under IFRS, Terasen Gas proposes a change in methodology from mass accounting to where the assets will be individually tracked, with gains and losses recorded on disposal and depreciation according to whole life rates developed by Gannett Fleming. The categories of general plant include:

- Frame structures
- Masonry structures
- Leased structures (depreciated over lease term)
- Computer software over $1M
- Vehicles
- Heavy work equipment
- Heavy mobile equipment

Instead these assets should be individually tracked and disposed of, there should be no negative salvage estimates involved, and any gains or losses on disposal should be recognized. We believe this change in methodology is required to be compliant with IFRS for general plant.

Should the Commission decide not to implement the recommended depreciation rates and in order to allow Terasen Gas to remain compliant with IFRS requirements, Terasen Gas requests the use of a deferral account to record the difference between the recommended depreciation rates as outlined in the current study and the rates that are eventually approved by the Commission. While the recommended depreciation rates are expected to be compliant with IFRS requirements, it is recognized that IFRS requirements in this area are evolving. As such, Terasen Gas requests the use proposed IFRS Transitional Deferral Account also be used to record any differences between the depreciation rates recommended in the study compared to that eventually required to comply with IFRS.

d) Overheads Capitalized

As outlined in previous years' Applications, Terasen Gas has identified the need for a change to its existing overhead rate. Since the previous Commission Decision accompanying Order No. G-7-03 in 2003 that concluded that the overhead capitalization rate of 16 per cent as a percentage of gross O&M, after removing items not eligible for capitalization such as vehicle lease, OPEB, demand side management and Pipeline Integrity Programs[205] continues to be a reasonable allocation of overhead

[205] Effective overhead capitalization rate is 13.8% after noted adjustments

costs to plant addition, Terasen Gas has completed a review of its overhead capitalized activities as part of this RRA.

The current study indicates an 8 per cent overhead capitalization rate as applied to gross O&M is appropriate. While this is significantly below the effective overhead capitalization rate of 13.8 per cent currently approved in rates, it is consistent and within a suitable range compared to the original Terasen Gas recommendation of roughly 10 per cent proposed in the 2003 Revenue Requirement Application. Contributing to the decrease from the 10 per cent overhead rate recommended by the prior study is exclusion of specific costs as a result of IFRS. Excluded costs from overhead capitalized include training activities, project investigation and approval activities, and those activities that are more general administration in nature.

Terasen Gas considers the results of the recent study as being reasonable and representative of the activities and related overhead costs that should be capitalized and will enable the Company to also comply with new IFRS requirements. Included in Appendix H-3, the current study and results are consistent with the prior study results, highlighting the ongoing difference between the Company's current overhead capitalization rate and that being recommended in the study. For validation, the recommended capitalization approach has been reviewed independently by KPMG to evaluate the suitability of the Company's approach. KPMG states in the study that it considers the *overhead capitalization results to be fair and reasonable.* KPMG is a major audit, tax and advisory services firm with significant experience in conducting overhead capitalization studies for utility clients.

Terasen Gas proposes the adoption of the recommended overhead capitalization rate of 8 per cent as indicated by the recent study and which is consistent with that originally proposed in the previous study. The 8 per cent recommended rate incorporates the known requirements of IFRS for determination of overhead capitalized at this time and appropriately captures costs that are directly linked to capital activity (new assets acquired or constructed), but due to the onerous nature of capturing these costs they are not directly assigned to capital costs. The revenue requirements and rate proposals included in this RRA reflect the recommended overhead capitalization rate of 8 per cent.

Should the Commission decide not to implement the recommended overhead capitalization rate of 8 per cent, and in order to allow Terasen Gas to remain compliant with IFRS requirements, Terasen Gas requests the use of a deferral account to record the difference between the recommended overhead capitalization rate as outlined in the current study and the rate that is eventually approved by the Commission. In addition, as mentioned earlier that IFRS requirements for determination of the overhead capitalized rate are evolving, Terasen Gas requests the proposed IFRS Transitional Deferral

Account also be used to record any differences between the rates recommended in the study compared to that eventually required to comply with IFRS.

(1) HISTORY

As part of its 1998-2002 PBR Application, Terasen Gas filed an overhead capitalized study and proposal to substantially reduce its capitalized overhead. The study recommended a capitalization rate of roughly 10 per cent of total O&M. By Order No. G-85-97, the Commission accepted the study and proposal and as part of the negotiated settlement approved reductions in the Company's overhead capitalization rate to 20 per cent in 1998, 20 per cent in 1999 and 16 per cent in 2000. The rate of 16 per cent was also approved for the one-year extension in 2001. However, the Commission's view was that any further reduction to capitalized overhead would have resulted in too large a rate impact for customers.

In its 2003 Revenue Requirement Application, Terasen Gas proposed the implementation of a capitalized overhead rate of 10 per cent starting in 2005. In its decision by Order No. G-7-03, the Commission concluded that the overhead capitalization rate of 16 per cent was a reasonable allocation of overhead costs to plant additions.

(2) HIGHLIGHTS

In evaluating cost drivers and methodologies to consider in allocating costs, Terasen Gas used the following criteria:

- Direct causal link of overhead costs to capital activity;
- Overhead costs must be distinguished from those that are directly charged to capital;
- Are the costs to be included in overhead incremental in nature (i.e. would not be incurred if the capital program were not required);
- Easy to follow methodology and calculations;
- The methodology should be free from bias and stable over time;
- The data used in the model should be accurate and can be relied upon; and
- The methodology and model should be cost effective to implement and maintain over time.

This resulted in Terasen Gas choosing the following cost allocation methods to use in determining the capitalized overhead pool.

For departments where there are identifiable, direct activities in support of capital activity (Distribution, Transmission, Marketing, Business Services, Regulatory and Finance), managers of the department were asked to conduct a detailed analysis to estimate the portion their employees' time related to capital activity but not being charged to capital directly. For these employees, a proportionate share of all their costs excluding labour time already directly charged to capital was then allocated to the capitalized overhead pool.

For support departments where a primary driver of their costs is influenced by the number of employees in the organization (Information Technology Support, Facilities Management, Human Resources Advisory), the departments' costs were allocated to the overhead pool based on the number of full time equivalent employees working on capital activity at Terasen Gas.

Insurance premiums paid for commercial liability policies were apportioned to the overhead pool based on proportion of dollars spent on Capital projects versus O&M activities (i.e. 30 per cent), as these costs are incurred for the Terasen Gas organization as a whole. The remaining corporate overhead costs, including future employee benefits and TGVI Shared Services recovery, were then allocated to the overhead pool based on a composite average calculated percentage.

Terasen Gas believes the recommended overhead capitalization rate incorporates IFRS requirements. Costs such as training costs which were previously included in capitalized overhead have now been excluded as part of the determination process in order to conform to IFRS.

(3) IMPLEMENTATION OF RECOMMENDATION

The following Table C-11-2 shows the proposed overhead capitalization rates and their impact on the revenue requirement.

Table C-11-3: Overheads Capitalized Decreases as a Percentage and in Total

Overhead Capitalized	2009 Projected	2010 Forecast	2011 Forecast
O/H Capitalized per cent	16 per cent	8 per cent	8 per cent
O/H Capitalized ($million)	28.1	16.8	17.5

With the proposed change to the capitalization rate from 16 per cent to 8 per cent, overhead capitalized is expected to decrease by $11.3 million from 2009 to 2010, composed of an $11.2 million decrease related to the rate change and a $1.3 million decrease related to rebasing of O&M, offset by a $1.2 million increase related to higher 2010 O&M forecast compared to 2009 projection. 2011 is expected to increase marginally as the result of higher forecasted O&M costs.

Terasen Gas believes the proposed overhead capitalization rate as outlined in the study included as Appendix H-3 is appropriate and representative of the activities and related overhead costs that should be capitalized. Terasen Gas proposes that the 8 per cent overhead capitalization rate be adopted, effective January 1, 2010, enabling the Company to comply with new IFRS requirements.

e) Shared Services Agreements

Sharing of resources between Terasen entities under Shared Services arrangements benefit the organizations involved as it enables the companies to harvest the benefits of economies of scale by having a single management and support structure while avoiding duplication of work and allowing customers to benefit from the efficiencies realized.

(1) TERASEN GAS AND TGVI SHARED SERVICES

Since the operational integration of Terasen Gas and TGVI in late 2003 and early 2004, Terasen Gas and TGVI customers have been able to enjoy the benefits of having a single management and support structure for the Terasen Utilities. Common services are being provided by Terasen Gas to TGVI on a Shared Services basis in order to meet each company's operating requirements.

Common services delivered on a Shared Services basis include:

- President's Office;
- Finance and Regulatory Affairs;
- Human Resources and Operations Governance;
- Gas Supply and Transmission;
- Business and Information Technology Services;
- Distribution; and
- Marketing.

(2) TERASEN GAS AND TGW SHARED SERVICES

Prior to 2010, the Shared Services agreement for the provision of administration and support services has been between TGVI and TGW, even though Terasen Gas has been providing the support since the operational integration of Terasen Gas and TGVI in 2004. At that time, with the adoption of a single management and support structure in support of Terasen Gas and TGVI customers, TGVI essentially stopped providing the support to TGW, with Terasen Gas assuming the role. Given the nature of the existing Shared Services agreement between TGVI and TGW in that it was previously negotiated as part of the 1999 ADR settlement negotiations, and for simplicity, TGW had decided to maintain the existing Shared Services agreement between itself and TGVI in the interim.

In this RRA, Terasen Gas is proposing to update the nature of the Shared Services agreement by putting itself instead of TGVI as the direct counterparty to TGW. Terasen Gas and TGW customers will continue to be able to enjoy the benefits of having a single management and support structure. Common services are being provided on a Shared Services basis by the single management and support structure in order to meet each company's operating requirements.

(3) SUMMARY OF RESULTS

<u>**Terasen Gas and TGVI Shared Services**</u>

Terasen Gas has completed a review of the Shared Services approach and agreement as part of this RRA For validation, the Shared Services approach and the reasonability of the costs of the Shared Services has been reviewed independently by KPMG to evaluate the suitability of the Shared Services agreement.[206] The results of the review indicate that the amount of annual Shared Services to be allocated from Terasen Gas to TGVI is estimated to be $7.6 million in 2010 and $8.0 million in 2011, subject to true-up of actual costs in 2012 on expiration of this RRA period. For example, the difference between the forecasted Shared Services and the actual costs for 2010 and 2011 combined will be recorded in 2012.

Terasen Gas considers the results of the review as being reasonable and representative of the activities and their value provided by the Company to TGVI. The cost allocation approach used for Shared Services costs between Terasen Gas and TGVI is the same as that established in 2004 and approved by the Commission in its Decision dated December 17, 2003 accompanying Commission Order No. G-80-03. KPMG found the allocation drivers used to be reasonable and the costs allocated to TGVI to be reasonable.

[206] See Appendix H-4 for a copy of KPMG's Shared Services Cost Allocation Review

The current allocation in comparison to the 2009 projection is significantly higher with increased levels and scope of work driving the increase. The increases in the 2010 Forecast recoveries compared to the 2009 projection total $2.8 million with $0.2 million related to Terasen Gas as the provider of Shared Services to TGW instead of TGVI (i.e. TGVI's O&M will show a reduction in recoveries for Shared Services). The remaining $2.5 million increase in recoveries by department is as follows:

- Marketing - $600 thousand for safety awareness messaging, responding to consumption information requests and development of new business opportunities and customer care services and contract administration;
- B&ITS - $800 thousand for support and training required for new IT applications and outsourced IT service provider contracts and Operations Engineering compliance activities. Of the increase, $170 thousand is related to the transfer of the recovery from the Operations Support previously discussed in the O&M section to under a Shared Service agreement.
- Transmission and Distribution - $150 thousand for additional integrity and asset management activities.
- HROG and Finance and Regulatory Affairs - $250 thousand for business continuity, emergency preparedness, leadership and professional development and additional support by HROG and $100 thousand for increased regulatory support.
- Labour inflation - $300 thousand allocated for Shared Services from Terasen Gas to TGVI
- Update of cost drivers - $400 thousand increase resulting from an update of the customer count ratio between Terasen Gas and TGVI used for allocating costs. In addition, there is an amendment in the methodology for allocating some of Distribution's costs, primarily in the Dispatch and Installation Centres. Instead of using the customer count ratio between Terasen Gas and TGVI, the revised approach is based on management's estimate of time required which Terasen Gas believes is more representative.

In 2011, Shared Services are expected to increase by a further $0.4 million with approximately half of the increase due to labour inflation and the remaining for department related increases.

Despite the higher costs, Terasen Gas and TGVI believe that by providing common services through a Shared Services approach, the costs are being optimized between the two organizations for the benefit of all customers. To properly reflect the value of activities provided by Terasen Gas to TGVI, the Company proposes the adoption of, and requests that the Commission approve, the allocation of costs for Shared Services between Terasen Gas and TGVI for the years 2010 and 2011, as reflected in the Shared Service Agreement between Terasen Gas and TGVI. [207]

Terasen Gas and TGW Shared Services

Terasen Gas has completed a review of the Terasen Gas and TGW Shared Services approach and agreement as part of this RRA. For validation, the Shared Services approach and proposed allocation for 2010 and 2011 has been reviewed independently by KPMG to evaluate the suitability of the Shared Services.[208] The results of the review indicate the amount of annual Shared Services to be allocated from Terasen Gas to TGW is estimated to be approximately $0.2 million in 2010 and 2011, subject to true-up of actual costs in 2012, on expiration of the RRA settlement period. For example, the difference between the forecasted Shared Services and the actuals for 2010 and 2011 combined will be recorded in 2012. The forecasted amounts for 2010 and 2011 are consistent with that currently allocated from TGVI to TGW.

Terasen Gas considers the results of the review as being reasonable and representative of the activities and their value provided by Terasen Gas to TGW. KPMG found the allocation drivers used to be reasonable and the costs allocated to TGW to be reasonable.

To properly reflect the value of activities provided by Terasen Gas to TGW, the Company proposes the adoption of, and requests that the Commission approve, the allocation of costs for Shared Services between Terasen Gas and TGW for the years 2010 and 2011, as reflected in the Shared Service Agreement between Terasen Gas and TGW.[209]

f) Transfer Pricing Policy and Code of Conduct Review

Since they were originally established in 1997 and approved by the Commission in Letter L-64-1997, the Terasen Gas Code of Conduct ("COC") and Transfer Pricing Policy ("TPP") have served to govern the relationships between Terasen Gas and Non-Regulated businesses ("NRB") regarding the provision of utility resources for unregulated activities including sharing of utility resources, the treatment of customer, utility or confidential information and the nature of the relationship between Terasen Gas and the NRBs. It has been over five years since both policies were evaluated with the most recent review occurring during the 2003 Multi Year Revenue Requirement and PBR Application. As part of this current Application and in follow-up to a letter by Terasen Gas dated December 12, 2007 agreeing to a

[207] See Appendix H-4(a) for a copy of TGI and TGVI Shared Services Agreement
[208] See Appendix H-4 for a copy of KPMG's Shared Services Cost Allocation Review
[209] See Appendix H-4(b) for a copy of TGI and TGW Shared Services Agreement

review of the both the COC and TPP as part of its next full Revenue Requirement Application, Terasen Gas has reviewed the COC and TPP to assess their appropriateness and whether amendments are required.

As a result of the review, no changes have been identified as Terasen Gas believes the COC and TPP are working as intended. The review of the TPP with the assistance of KPMG[210] suggests that the current transfer pricing policy and model used to charge NRBs by the Utility are reasonable and complete, Terasen Gas believes the COC remains suitable and appropriate to govern utility interaction with NRBs for the period of the Application recognizing though that the energy marketplace continues to evolve in British Columbia.

Terasen Gas proposes no changes to the existing COC and TPP. Both policies are expected to continue to provide appropriate direction and rules to govern the interaction of Terasen Gas and its NRBs during the period of the current Application. Further, Terasen Gas believes that the processes in place and the two independent compliance reviews conducted annually by Terasen Gas' Internal Audit group and its external auditors provide a sufficient level of assurance to ratepayers, stakeholders and the Commission.

(1) COMPLIANCE WITH CODE OF CONDUCT AND TRANSFER PRICING POLICIES

Terasen Gas complies with the COC and the TPP for provision of Company resources and services by having its employees charge out their time to NRBs. Employees currently keep track of the time they spend on NRB's activities. Their salary costs, loaded for benefits and concessions, and an overhead charge for the use of facilities and other resources, and in some cases, an availability and supervisory surcharge are charged to the NRB. This process is managed through the continuing services contracts between the Company, the NRBs and FortisBC:

- Terasen Inc.
- Terasen Energy Services Inc.
- Inland Energy Corp.
- Terasen Huntingdon Inc.
- FortisBC

Non-utility activities performed on behalf of Terasen and other NRBs are charged 100 per cent to Terasen and to the NRBs respectively. This is managed through monthly timesheets and appropriate

[210] See Appendix H-6 for a copy of the KPMG Transfer Pricing Report

charge codes for each NRB. For 2010 and 2011, it is expected that Terasen Gas will charge Terasen and other NRBs $0.34 million and $0.35 million including the recovery of overheads for the benefit of Terasen Gas and its ratepayers.

To ensure that Terasen Gas' practices and processes comply with the policies and as one of the conditions of the negotiated settlement for the 2004 – 2007 Performance Based Rate plan, the Terasen Gas' Internal Audit group completes a review of compliance with the COC and TPP annually with a report provided summarizing the results of the review. In addition, Terasen Gas' independent external auditor reviews the work performed by Terasen Gas' Internal Audit group. This practice has worked over the years with any issues and exceptions that are identified promptly addressed by Terasen Gas management.

Upon further review of the current compliance review process for the COC and TPP, Terasen Gas proposes the elimination of the independent external auditor review requirement as it is duplication of the work performed by Terasen Gas' Internal Audit group. The elimination of this requirement will not compromise the compliance process for the COC and TPP

(2) REVIEW OF CODE OF CONDUCT AND TRANSFER PRICING POLICY

In reviewing the COC as it applies to Terasen Gas' NRB activities, two sections are worth elaborating further on here with the provisions being (#4) Provision of Information and (#6) Equitable Access to Services.

(#4) Provision of Information states that Terasen Gas will not provide to an NRB any information that would inhibit a competitive energy services market from functioning. This precludes Terasen Gas from releasing confidential customer specific information without the consent of that customer. It is standard practice for Terasen Gas and its NRBs to seek permission from the customer to obtain any specific customer data and personal information that Terasen Gas may hold prior to releasing the information.

(#6) Equitable Access to Services states that except as required to meet acceptable quality and performance standards, and except for some specific assets or services which require specific consideration as approved by the Commission, Terasen Gas will not preferentially direct customers seeking specific competitively offered services to an NRB or specific retailer.

The COC was developed in response to the Retail Markets Downstream of the Meter ("RMDM") guidelines published in April, 1997 which provides Commission guidance with respect to utility or NRB participation in downstream retail markets which may include any utility or energy related activity at or downstream of the utility meter. As described in the RMDM guidelines, the retail market downstream of the utility meter can be generally described as consisting of those goods and services which are related to or support the delivery and/or use of the energy commodity.

Over the past decade, Terasen Gas believes that the existing COC has served its purpose well in providing guidance for how the utility or its affiliate can compete in the retail marketplace, where providing preferential direction could possibly provide an unfair advantage and/or hinder the development of a competitive retail marketplace. However, in situations where the service or product is upstream of the meter, such as providing alternative energy delivery systems that use a number of energy sources including renewable fuels such as geothermal and solar integrated with conventional energy forms of natural gas and electricity, Terasen Gas believes that section (#6) of the Code of Conduct may not apply as the section was developed primarily with the retail marketplace, rather than the upstream of the meter marketplace. Terasen Gas believes that customers seeking services and products upstream of the meter are generally more sophisticated and knowledgeable than the average retail consumer and that choice available in the upstream marketplace is much more limited than in the retail marketplace. As a result, Terasen Gas believes there is no significant advantage conferred to the NRB if customers seeking services upstream of the meter are directed to the NRB by the Utility with consent provided by the customer.

In reviewing the TPP, Terasen Gas updated the current transfer prices charged to NRBs by the Utility. Labour charge rates including benefits and concessions, the overhead charge for the use of facilities and other resources and the supervisory surcharge were reviewed for reasonableness, using current costs and estimates.

The results of the review indicate that while some cost components may have changed from that being charged to NRBs today, the changes are in the overall scheme immaterial and provide support to Terasen Gas' belief that the current transfer prices to NRB are appropriate for the period of the Application.

g) Corporate Services

Since TGI's last RRA, the ownership of Terasen has changed twice, which has resulted in significant changes in how certain functions have been provided to Terasen Gas. In this application, Terasen Gas is proposing to update the nature of the costs that are allocated and the cost allocation drivers to align with Terasen's current ownership structure, as reflected in a new Corporate Services Agreement between Terasen and Terasen Gas.

Prior to 2004, Terasen Gas performed certain corporate service functions and cross-charged Terasen and its subsidiaries according to the terms of the Code of Conduct and Transfer Pricing Policy. In 2004, certain functions which were performed by Terasen Gas were separated and transferred into Terasen. These corporate services were then contracted back to Terasen Gas by Terasen through a Corporate Services Agreement, using a cost allocation methodology established and approved by Commission Order No. G-80-03. As a result of this re-organization, the Corporate Centre at Terasen Inc was established, consistent with the direction given in the Commissions Decision issued on February 4th, 2003 pursuant to Commission Order No. G-80-03.

Today, while the corporate services are still contracted to Terasen Gas through Terasen, these services are now performed by a mix of Terasen and Fortis. The corporate services group at Terasen consists of the following functions:

- Corporate Development, Treasury and Cash Management
- External Reporting
- Taxation Services
- Corporate Financial Analysis and Capital Management
- Internal Audit
- Risk Management and Insurances Services
- Corporate Secretary and Board of Directors
- Legal Department
- Human Resources Compensation and Planning

The services performed by Fortis (and provided to Terasen) tend to be more strategic in nature and consist of the following functions:

- Office of the CEO
- Office of the CFO
- Treasury and Taxation
- Investor Relations
- Financial Reporting
- Internal Audit

- Corporate Secretary and Board of Directors

A more detailed description of the services provided by both companies can be found in Appendix H-5.

In determining the corporate services fee charged to Terasen Gas by Terasen, both Terasen and Fortis have reviewed the costs incurred in 2008 and the budgeted costs anticipated in 2009. Each company then adjusted for costs specifically not allowed by the Commission in past applications (i.e., stock option costs). Once these costs have been excluded, the remaining costs are allocated from Fortis to Terasen, and then from Terasen to Terasen Gas based on various cost drivers. The methodology selected by Terasen incorporates the Massachusetts formula[211] which is the same allocation methodology previously approved by the Commission. The costs from Fortis are allocated to Terasen using an assets by subsidiary driver which is a valid cost driver given the organizational structure of Fortis.

Terasen has completed a review of the Corporate Services approach and agreement as part of this RRA. For validation, the Corporate Services approach and proposed allocation for 2010 and 2011 has also been reviewed independently by KPMG to evaluate and validate the approach, allocation methodology and suitability of the Corporate Services agreement[212]. The results of the review indicate that the annual Corporate Services to be allocated from Terasen to Terasen Gas are estimated to be approximately $9.0 million in 2010 and $9.1 million in 2011.

Terasen Gas considers the results of the review to be reasonable and representative of the activities and their value provided by Terasen to Terasen Gas. As previously described, the cost allocation approach used for the Corporate Services between Terasen and Terasen Gas is similar to the methodology previously established and approved by Commission Order No. G-80-03.

While the corporate services fee charged to Terasen Gas is higher than in the past number of years, the management fee was frozen at the time of the acquisition of Terasen by KMI in late 2005. Since 2005, the delivery of these services has been provided by a mix of those functions still at Terasen and either KMI or Fortis, depending on the time period. The fee has increased due to fewer subsidiaries being owned by Terasen and so the Company is bearing a higher percentage of the costs. In 2006, Terasen sold its water and utility services business and in 2007, as part of the sale of Terasen to Fortis, Terasen disposed of the petroleum transportation business, both of which Terasen had previously provided

[211] The Massachusetts Formula is in extensive use in industry and is composed of the arithmetical average of (1) operating revenue, (2) payroll, and (3) average net book value of tangible capital assets plus inventories. The use of these factors represents the total activity of all business segments as a means to allocate costs that cannot be directly assigned.

[212] See Appendix H-5 for a copy of the KPMG review of the Corporate Services approach

similar shared services to. Offsetting the cost increases are some cost savings on the allocation of the management fee from Fortis to Terasen. Fortis owns a larger number of subsidiaries than those owned previously by Terasen and the fee reflects a lower cost allocation of those services. Additionally, the cost of service has increased due to inflation, which has not been reflected in the fee charged since 2005.

To properly reflect the value of activities provided by Terasen to Terasen Gas, the Company proposes the adoption, and requests that the Commission approve the allocation of costs for shared Corporate Services between Terasen and Terasen Gas for the years 2010 and 2011, as reflected in the Corporate Services Agreement between Terasen and Terasen Gas.[213]

h) Accounting and Other Policies Summary

The impacts of the accounting and other policies discussed above have been reflected appropriately in the RRA, affecting primarily capital and O&M expenses. The policies that were reviewed and adopted by Terasen Gas in creating this Application reflect the most appropriate methodologies for cost recovery in 2010 and 2011, while incorporating the latest updates from accounting standard setting bodies, and considering general principles of regulatory cost allocation.

[213] See Appendix H-5(a) for the Corporate Services Agreement between Terasen Inc. and Terasen Gas Inc.

12. Tariff Changes

The Terasen Gas Tariff sets out the General Terms and Conditions ("GT&C") regarding the provision of service to our customers. Specific terms and conditions of service for each of the different customer classes served by the Company are set out in the various Rate Schedules included in the Company's Tariff.[214] In order to continue to provide our customers with quality service it is necessary from time to time to propose revisions to the Tariff. This Application presents an appropriate opportunity to propose several necessary Tariff amendments, to be effective January 1, 2010.

The Company is seeking three different types of Tariff changes with this Application:

- The addition of two new Rate Schedules to offer enhanced service to customers in the transportation sector, as described in Part III, Section C, Tab 3 ;
- Changes to two of the fees charged to customers, as set out in the GT&C; and
- New terms and conditions to support the alternative energy solutions described in Part III, Section C, Tab 3.

The Company's proposals under each of these three types of changes are discussed in detail in the following sections.

a) New Rate Schedules

As described in Part III, Section C, Tab 3, we propose two new rate schedules in order to provide enhanced service to customers in the transportation sector:

5. Rate Schedule 6C – Natural Gas Compression and Refuelling Service
6. Rate Schedule 26 – Natural Gas Vehicle Transportation Service

The rate schedules will reduce existing impediments to the development of the NGV industry. The development of NGV benefits existing customers through more efficient use of infrastructure, benefits potential NGV customers by providing a competitive fuel alternative; and is consistent with government policy. We have included pro-forma Tariff pages in Appendix J-4: Rate Schedule 26: NGV Transportation Service and Appendix J-6: Rate Schedule 6C: Compression and Refueling Service and respectfully request Commission approval of the proposed rate schedules to be effective January 1, 2010.

[214] See Appendix J-1 for a copy of TGI Historical Tariff Continuity Tables and Rates

If Rate Schedule 6C is approved, we also seek approval to cancel Rate Schedule 6A – General Service – Vehicle Refueling Service, as it will be redundant. We have included the blacklined Tariff pages in Appendix J-5: Rate Schedule 6A Cancelled and respectfully request Commission approval of the proposed Tariff page changes.

b) Changes to Standard Fees and Charges

We propose changes to two fees that are included in the Standard Fees and Charges Schedule of the GT&C:

7. Reduce the Application Fee for new installations from $85 to $25.
8. Increase the Meter Testing Fee from $30 to $60.

The proposed change to the Application Fee reasonably reflects the cost of providing service. It is similar to the fee charged by other utilities. The proposed change to the Meter Testing Fee reasonably reflects the cost of providing service and reduces impact to existing customers. In both cases the proposed change is to reasonably reflect the cost of providing the services and is consistent with cost causation principles.

A summary of the proposed changes is presented in Table C-12-1 which follows.

Table C-12-1: Proposed Fee Changes

TGI Tariff – Standard Fees and Charges Schedule	Proposed Changes
Application Fee Existing Installation $25.00 New Installation $85.00 New Installation: Manifold Meters $85.00 Vertical Subdivision $85.00	Reduce New Installation Application Fee to $25
Metering Related Fees Disputed Meter Testing Fees Meters rated less than or equal to 14.2m3/hr: $30.00 Meters rated greater than 14.2m3/hr : Actual Costs of Removal and replacement	Increase charge to $60 for Meters rated less than or equal to 14.2m3/hr

The proposed changes are described below.

(1) REDUCTION IN THE APPLICATION FEE

The current $85 Application Fee for new installations was approved in 1996. Since then, processes have been streamlined. The cost of providing this service is now much lower. The Application Fee should be reduced to reasonably reflect the cost of providing this service.

On December 6, 2007, the Commission issued the *TGI – TGVI System Extension and Customer Connection Policies Review Decision.* The Commission's Decision (pg. 53) directed TGI and TGVI to address the $85 Application Fee in their next revenue requirements applications:

> ***"6.1 New Customer Application Fee***
>
> *Terasen proposes no change to the $85 new customer Application Fee, stating that 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 and has*

been in place at $85 since prior to 1996. Terasen states that since then the processes have been streamlined and costs to enroll customers into the system have remained relatively stable or have declined and that customer enrolment for the Companies' customers is performed by CustomerWorks LP, as part of a bundled suite of services which include billing, meter reading, customer contact (call centre operations) and credit and collections. As the agreement and contract with CustomerWorks LP is for a bundled service, Terasen is unable to determine the specific cost to enroll an individual customer, but states that since enrolment costs are only a portion of the per customer total suite of costs charged to the Companies, (for 2007, $55.36 for TGI, and $43.07 per customer for TGVI) enrolment costs are less than they were in 1996 (Exhibit B-3, BCUC 1.18.1-3).

Terasen states that it intends to make a further assessment of the value of reducing the $85 fee in the future, but that, since the current PBR Settlement Agreement includes revenue from the $85 fee, Terasen is of the view that the level of this fee should not be changed before the Settlement Agreements expire at the end of 2009 (Exhibit B-9, BCUC 2.45.1).

Commission Determination

The Commission Panel finds little on the record before it to justify either the existence or quantum of Terasen's $85.00 Application Fee and accordingly directs both TGI and TGVI to address both matters at their next RRA following the expiry of their Settlement Agreements at the end of 2009."

The Application Fee is related to the creation of a new customer account. We believe the proposed reduction in the Application Fee reasonably reflects the cost of creating a new customer account, and reflects a portion of the CustomerWorks LP bundled services charge. The $25 fee is similar to the fee charged by other utilities. The lower Application Fee also supports customer growth as it reduces the cost of new customers attaching to the gas distribution system.

CustomerWorks LP continues to provide a bundled suite of services which includes: billing, meter reading, customer contact (call centre operations) and credit and collections. A bundled rate per customer is charged for the services (for 2008, approximately $55 for Terasen Gas, and approximately $42 per customer for TGVI). Due to the bundled rate, we are unable to determine the specific CustomerWorks LP administration costs, included in that bundled rate, associated with initiating service to a new customer or creating a new account. Since the task of initiating service to a new customer is only a portion of the bundled services we have determined that the associated administration costs are less than the current $85 Application Fee and the bundled rate.

The $85 Application Fee was approved in 1996 and based on a 1993 methodology. As presented in Table C-12-2, the proposed $25 Application Fee represents a cost estimate of creating a new customer account using the 1993 methodology taking into consideration the current process.

Table C-12-2: Process Comparison (2009 versus 1993)

		New Account - New Service Required			
1993 Activity No.	**1993 Description**	**1993 BC Gas**	**2009 TGI & TGVI**	**2009 CWLP**	**Process Change/Comments**
a	The Applicant's information is obtained either over the telephone or at a branch office.	Clerical time. Associated overhead. **(Clerical Time = $35.21)**	Install Center (Customer Contract Representative or Planning & Design Technician).	None.	Order Fulfillment process. Gas Application is processed in CAFÉ.
b	The Applicant's information is keyed in the Company's computer system	Clerical time. Computer system utilization. Associated overhead. **(Computer System Utilization = $4.71)**	Install Center (Customer Contract Representative or Planning & Design Technician).	None.	Activity a & b occur at the same time.
c	An evaluation of the Applicant's credit worthiness is determined and, if any outstanding bills from other accounts exist, collection activities are undertaken before new service is provided.	Clerical time. Computer system utilization. External collection costs. Associated overhead.	None.	Clerical time. Computer system utilization. External collection costs. Associated overhead. **(Cost Estimate = 0.25 hr x $60/hr = $15).**	CWLP received premise-out report. Manually enters customer and premise data in new account (10 mins). CWLP conducts credit check (5-10 mins). Assumes $60/hr including labour, benefits, overheads, computer system utilization.
h	When a new service installation is required, additional information is required for permanent installation records and a site visit prior to installation is necessary for 20 - 25% of all installations. Following installation of the new service, site records are completed in greater detail.	Clerical time. Computer system utilization. Mains and services representatives and vehicles. Associated overhead. **(Site Visit/Confirmation = $53.91)**	2003 Order Fulfillment process. Crews will install service and meter and complete as-built records. T-Doc sent to Closing Desk.	Clerical time. Computer system utilization. External collection costs. Associated overhead. **(Cost Estimate = 0.15 hr x $60/hr = $10).**	CWLP receives bill-out/meter movement report. Manually enters meter number, meter reading, charges (10 mins).
Summary		New Account cost estimate = $93.86 **$75 Proposed & Approved in 1993. $85 Approved for 1996.**	Not Applicable. Customer enrollment/account set-up by CWLP.	**Total Cost Estimate = (0.4 hr)($60/hr) = $24. Propose $25 Application Fee to create new customer account.**	Significant automation since 1993. Enrolment costs are only a portion of the per customer total suite of costs charged to TGI and TGVI. Bundled service rate, therefore unable to determine the set-up new accounts.

Since 1993, processes have been streamlined and costs to enroll customers into the system have remained relatively stable or have declined. For example, in 2003 process changes were implemented. The new customer attachment process required increased information from the applicant resulting in a significant reduction in site visits for service installations. In addition, the field crews were responsible for recording the service installation details (as-built sketch) thus eliminating the need for a planner to visit the site following the service installation. Currently, the creation or set-up of new customer accounts in the customer information system for the Companies' customers is performed by ABSU (on behalf of CustomerWorks LP), as part of a bundled suite of services which include billing, meter reading, customer contact (call centre operations) and credit and collections. Based on a current process review and assumptions, it is estimated that the total duration required to create a new account in the customer information system is approximately 0.4 hours (20 minutes). The combined all inclusive, loaded labour and system utilization rate is assumed to be $60/hour. Therefore, the estimated cost to create a new customer account is approximately $25.

For comparison, the fee/charge from other utilities was reviewed and is presented below. Due to the fact that each utility has a different methodology for system extensions and application fees it is not possible to complete a direct comparison. However, the table highlights that the majority of the other utilities have a fee/charge which is significantly less than Terasen Gas' current $85 Application Fee.

Table C-12-3: Application Fee for Other Utilities

Utility	Location	Application Fee
Pacfic Northern Gas	British Columbia	The Ft. St. John and PNG West service areas have an application fee of $30. The Dawson Creek service area has a fixed charge of $150.
Atco Gas	Alberta	Basic charge of $100.
Altagas	Alberta	$35
Union Gas	Ontario	It is Union's practice to not charge customers an application fee for a new service if they commit to install a natural gas furnace or natural gas-powered appliance that operates as a main heat source (i.e. fireplace). If the customer does not plan to install a furnace but some other natural gas appliance(s), Union will usually run an economic analysis to ensure the gas load covers the cost of the gas service. In the event there's an economic shortfall, the customer requesting the gas service may receive a charge.
Enbridge Gas	Ontario	$25
Gaz Metro	Quebec	There is no application fee.
BC Hydro	British Columbia	Account Charge - $12.40.
FortisBC	British Columbia	Charge for Service - $27.00. This is a charge for a meter connection, transfer of an account involving either a meter connection or a meter reading, or recconnection of a meter after disconnection. There is a $6.00 charge for the transfer of an account not involving a meter reading.

The current Application Fee for New Installation, New Installation (Manifold Meters and – Vertical Subdivisions) is $85 as specified in the Tariff under the Standard Fees and Charges Schedule. We propose reducing the Application Fee from $85 to $25.

In terms of the Main Extension Test, we have confirmed that the reduced revenues resulting from a lower Application Fee will immaterially lower the Profitability Index and will not substantially impact new main extensions.

We believe the proposed reduction in the Application Fee from $85 to $25 reasonably reflects our cost estimate of creating a new customer account, reflects an appropriate allocation of the CustomerWorks LP bundled services charge and is similar to the fee charged by other utilities. The lower Application Fee also supports customer growth as it reduces the cost of new customers attaching to the gas distribution system.

TGVI has proposed a similar change in its 2010-2011 Revenue Requirements Application. If the Customer Care Enhancement CPCN is approved, we will revisit this fee if it is appropriate to maintain consistency with the principle of cost causality.

(2) INCREASE METER TESTING FEE

The Meter Testing Fee is applied when a customer requests the meter be tested for accuracy and the results from Measurement Canada confirm that the meter meets standards. The fee is to ensure that the cost of providing this service does not negatively impact other customers. Conversely, if the results from Measurement Canada confirm that the meter does not meet standards, then the customer will not be charged the Meter Testing Fee and the Company is responsible for the cost of providing this service.

For meters rated less than or equal to 14.2m3/hr the current charge of $30 has not changed since prior to 1994. We believe the current charge does not reasonably reflect the cost of providing this service. Therefore, we propose to increase the Meter Testing Fee from $30 to $60. The proposed Meter Testing Fee of $60 is based on the following cost estimate to provide this service:

Table C-12-4: Meter Testing Fee Cost Estimate

Task Description	**Calculation**	**Cost Estimate**	***Comment***
Meter exchange appointment	$6	$6.00	*Average $6/appointment*
Meter exchange by technician	0.75 hr x $73/hr	$54.75	*0.75 hours includes time travel, exchange, relight. $73 represents 2010/11 loaded hourly rate (Interior & Coastal average) with vehicle.*
Total		$60.75	
Proposed Meter Testing Fee		***$60***	

Measurement Canada does not charge the customer a fee for meter testing.

We believe the proposed increase reasonably reflects the current cost of this service and hence mitigates negative impacts to other customers.

We do not propose a change for meters rated greater than 14.2m3/hr since customers are charged the actual costs of removal and replacement.

TGVI follows the same meter testing process and is seeking a similar change in its 2010-2011 Revenue Requirements Application.

The proposed changes to the Application Fee and Meter Testing Fee reasonably reflect the cost of providing the service and is consistent with cost causation principles. We have included blacklined Tariff pages in Appendix J-2: Standard Fees and Charges Schedule and respectfully request Commission approval of the proposed Tariff page changes.

c) New Terms and Conditions

As described in Part III, Section C, Tab 3 the Company proposes alternative energy solutions including geo-exchange, solar-thermal and district energy systems as extensions of the gas service provided by the Company. We propose new Tariff terms and conditions as an addition to the GT&C to support the alternative energy solutions. A new Section 12A – Alternative Energy Extensions will describe the alternative energy extensions: geo-exchange, solar-thermal and district energy systems. It also describes the proposed cost of service model approach to establishing a rate for each offering. As described in Part III, Section C, Tab 3, the service agreements and rates will be filed separately as contracts. We have included pro-forma and blacklined Tariff pages in Appendix J-3: Alternative Energy Extensions and respectfully request Commission approval of the proposed Tariff page changes effective January 1, 2010.

13. Financial Schedules

Summary of TGI 2010 and 2011 Revenue Requirement Increase

Section C
Tab 13
Schedule 1

		2010 ($ Millions)		Incremental 2011 ($ Millions)	Cumulative 2011 ($ Millions)
Rebase from Formula Capital and O&M					
Rate Base- Net Plant in Service					
Equity Finance Expense	$ (2.0)		$ -		
Debt Finance Expense	(3.0)		-		
Utility O&M	(8.0)		-		
Overheads Capitalized	1.3				
After Tax Depreciation	(10.0)		-		
Tax Impacts of Rebase Depreciation	(4.3)		-		
Other Revenue	2.6		-		
Taxes	1.0	$ (22.4)	-	$ -	$ (22.4)
Volumes/Revenue Related					
Change in Gross Margin due to Customer Growth	$ (4.6)		(3.7)		
Change in Use Rate	(4.7)		4.7		
Change in Other Revenue	(1.6)		(1.9)		
All Others	(1.8)	(12.7)	(1.5)	(2.4)	(15.1)
O&M Forecast					
Change in overheads capitalized- change in O&M	(1.2)		(0.7)		
Change in O&M & Vehicle Lease Forecast	14.9	13.7	11.5	10.8	24.5
Depreciation & Amortization Forecast					
After Tax Change in Depreciation from GPIS Additions/Retirements	3.7		2.3		
Change in Amortization	(2.2)	1.5	4.0	6.3	7.8
Other					
Higher Property Taxes	1.6		1.0		
Change in Income Tax Expense	(0.4)		(0.1)		
Rate Base changes to support customer growth	1.8		2.5		
Interest Expense	2.1		5.4		
Rounding Difference	0.2	5.3	(0.1)	8.7	14.0
Total Revenue Increase/(Decrease) Before Accounting Standard Changes		$ (14.6)		$ 23.4	$ 8.7
Accounting Standard Changes					
Change in Overhead Capitalized Rate & Methodology	11.2		-		
Impacts on O&M	(0.3)	10.9	(2.0)	(2.0)	8.9
After Tax change in Depreciation Rates	20.8		0.4		
After Tax change in Depreciation Commencement	1.9		-		
Tax Impacts of Depreciation Changes	9.0	31.7	0.1	0.5	32.2
Total Revenue Increase from Accounting Standard Changes		$ 42.6		$ (1.5)	$ 41.1
Net Revenue Increase (Section C, Tab 13-1, Schedule 2 and 3, Column 6, Line 15)		**$ 27.9**		**$ 21.9**	**$ 49.8**

June 12, 2009

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Core	2010 Non-Core	2010 Bypass and Special Rates	2010 Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$1,451,464	$1,414,636	$61,280	$12,081	$1,487,998	$36,534	- Tab C-13, Schedule 16
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue / Terasen Gas (Vancouver Island)	14,561	-	-	16,276	16,276	1,715	- Tab C-13, Schedule 26
8								
9	Total Revenue	1,466,025	1,414,636	61,280	28,357	1,504,274	38,249	
10								
11	Less - Cost of Gas	(931,546)	(974,078)	(703)	(816)	(975,597)	(44,051)	- Tab C-13, Schedule 19
12								
13	Gross Margin	$534,479	$440,558	$60,577	$27,541	$528,677	($5,802)	
14								
15	Revenue Deficiency (Surplus)	$0	$24,497	$3,368	$0	**$27,865**		
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	0.00%	5.56%	5.56%	0.00%	5.27%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	0.00%	1.73%	5.50%	0.00%	1.85%		
20								

TERASEN GAS INC. June 12, 2009 Advance Materials Section C
Tab 13
Schedule 3

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Core	2011 Non-Core	2011 Bypass and Special Rates	2011 Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$1,487,998	$1,416,102	$61,336	$12,081	$1,489,519	$1,521	- Tab C-13, Schedule 17
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue / Terasen Gas (Vancouver Island)	16,276	-	-	18,253	18,253	1,977	- Tab C-13, Schedule 27
8								
9	Total Revenue	1,504,274	1,416,102	61,336	30,334	1,507,772	3,498	
10								
11	Less - Cost of Gas	(975,597)	(975,090)	(703)	(821)	(976,614)	(1,017)	- Tab C-13, Schedule 21
12								
13	Gross Margin	$528,677	$441,012	$60,633	$29,513	$531,158	$2,481	
14								
15	Revenue Deficiency (Surplus)	$27,865	$43,821	$6,025	$0	**$49,846**		
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	5.27%	9.94%	9.94%	0.00%	9.38%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	1.85%	3.09%	9.82%	0.00%	3.31%		
20								

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Existing 2009 Rates	2010 ----Revised Rates----- Revised Revenue	2010 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	115,723	112,423	-	112,423	(3,300)	- Tab C-13, Schedule 14
3	Transportation	89,214	88,255	-	88,255	(959)	- Tab C-13, Schedule 14
4		204,937	200,678	-	200,678	(4,259)	
5							
6	Average Rate per GJ						
7	Sales	$11.902	$12.583	$0.000	$12.801	$0.899	
8	Transportation	$0.830	$0.831	$0.000	$0.869	$0.039	
9	Average	$7.000	$7.415	$0.000	$7.554	$0.554	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,377,376	$1,414,636	$0	$1,414,636	$37,260	- Tab C-13, Schedule 16
13	- Increase / (Decrease)	-	-	24,497	24,497	24,497	- Tab C-13, Schedule 22
14	RSAM Revenue	(17,004)					
15	Transportation - Existing Rates	74,087	73,362	-	73,362	(725)	- Tab C-13, Schedule 16
16	- Increase / (Decrease)	-		3,368	3,368	3,368	- Tab C-13, Schedule 22
17	**Total**	1,434,459	1,487,998	27,865	1,515,863	64,400	
18							
19	Cost of Gas Sold (Including Gas Lost)	931,546	975,597	-	975,597	44,051	- Tab C-13, Schedule 19
20							
21	**Gross Margin**	502,913	512,401	27,865	540,266	20,349	
22							
23	Operation and Maintenance	165,162	192,823	-	192,823	27,661	- Tab C-13, Schedule 28
24	Vehicle Lease	1,804	-	-	-	(1,804)	
25	Property and Sundry Taxes	47,593	49,193	-	49,193	1,600	- Tab C-13, Schedule 31
26	Depreciation and Amortization	79,725	103,796	-	103,796	24,071	- Tab C-13, Schedule 33
27	Other Operating Revenue	(20,906)	(22,422)	-	(22,422)	(1,516)	- Tab C-13, Schedule 26
28		273,378	323,390	-	323,390	50,012	
29	Utility Income Before Income Taxes	229,535	189,011	27,865	216,876	(12,659)	
30							
31	Income Taxes	23,010	23,683	7,939	31,622	8,612	- Tab C-13, Schedule 35
32							
33	**EARNED RETURN**	$206,525	$165,328	$19,926	$185,254	($21,271)	- Tab C-13, Schedule 10
34							
35							
36	**UTILITY RATE BASE**	$2,412,321	$2,535,487	$400	$2,535,887	$123,566	- Tab C-13, Schedule 8
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	8.56%	6.52%		7.31%	-1.25%	- Tab C-13, Schedule 10

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Existing 2009 Rates	2011 ----Revised Rates----- Revised Revenue	2011 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	112,423	112,326	-	112,326	(97)	- Tab C-13, Schedule 15
3	Transportation	88,255	88,438	-	88,438	183	- Tab C-13, Schedule 15
4		200,678	200,764	-	200,764	86	
5							
6	Average Rate per GJ						
7	Sales	$12.801	$12.607	$0.000	$12.997	$0.196	
8	Transportation	$0.869	$0.830	$0.000	$0.898	$0.029	
9	Average	$7.554	$7.419	$0.000	$7.668	$0.114	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,414,636	$1,416,102	$0	$1,416,102	$1,466	- Tab C-13, Schedule 17
13	- Increase / (Decrease)	24,497	-	43,822	43,822	19,325	- Tab C-13, Schedule 24
14							
15	Transportation - Existing Rates	73,362	73,417	-	73,417	55	- Tab C-13, Schedule 17
16	- Increase / (Decrease)	3,368		6,024	6,024	2,656	- Tab C-13, Schedule 24
17	**Total**	1,515,863	1,489,519	49,846	1,539,365	23,502	
18							
19	Cost of Gas Sold (Including Gas Lost)	975,597	976,614	-	976,614	1,017	- Tab C-13, Schedule 21
20							
21	**Gross Margin**	540,266	512,905	49,846	562,751	22,485	
22							
23	Operation and Maintenance	192,823	201,617	-	201,617	8,794	- Tab C-13, Schedule 28
24	Vehicle Lease	-	-	-	-	-	
25	Property and Sundry Taxes	49,193	50,211	-	50,211	1,018	- Tab C-13, Schedule 32
26	Depreciation and Amortization	103,796	110,496	-	110,496	6,700	- Tab C-13, Schedule 34
27	Other Operating Revenue	(22,422)	(24,359)	-	(24,359)	(1,937)	- Tab C-13, Schedule 27
28		323,390	337,965	-	337,965	14,575	
29	Utility Income Before Income Taxes	216,876	174,940	49,846	224,786	7,910	
30							
31	Income Taxes	31,622	18,448	13,206	31,654	32	- Tab C-13, Schedule 36
32							
33	**EARNED RETURN**	$185,254	$156,492	$36,640	$193,132	$7,878	- Tab C-13, Schedule 11
34							
35							
36	**UTILITY RATE BASE**	$2,535,887	$2,619,914	$427	$2,620,341	$84,454	- Tab C-13, Schedule 9
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.31%	5.97%		7.37%	0.07%	- Tab C-13, Schedule 11

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Existing 2009 Rates	2010 ----Revised Rates----- Revised Revenue	2010 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$206,525	$165,328	$19,926	$185,254	($21,271)	- Tab C-13, Schedule 4
3	Deduct - Interest on Debt	(108,525)	(110,050)	(6)	(110,056)	(1,531)	- Tab C-13, Schedule 10
4	Add- Non-Tax Ded. Expense (Net)	428	(1,864)	-	(1,864)	(2,292)	- Tab C-13, Schedule 37
5							
6	Accounting Income After Tax	98,428	53,414	19,920	73,334	(25,094)	
7	Add (Deduct) - Timing Differences	(44,736)	5,999	-	5,999	50,735	- Tab C-13, Schedule 37
8							
9	Taxable Income After Tax	$53,692	$59,413	$19,920	$79,333	$25,641	
10							
11		30.000%	28.500%	28.500%	28.500%	-1.500%	
12	1 - Current Income Tax Rate	70.000%	71.500%	71.500%	71.500%	1.500%	
13							
14	Taxable Income	$76,703	$83,095	$27,860	$110,955	$34,252	
15							
16	**Total Income Tax**	$23,011	$23,682	$7,940	$31,622	$8,611	
17							

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Existing 2009 Rates	2011 Revised Rates Revised Revenue	2011 Revised Rates Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$185,254	$156,492	$36,640	$193,132	$7,878	- Tab C-13, Schedule 5
3	Deduct - Interest on Debt	(110,056)	(115,417)	(13)	(115,430)	(5,374)	- Tab C-13, Schedule 11
4	Add- Non-Tax Ded. Expense (Net)	(1,864)	1,974	-	1,974	3,838	- Tab C-13, Schedule 38
5							
6	Accounting Income After Tax	73,334	43,049	36,627	79,676	6,342	
7	Add (Deduct) - Timing Differences	5,999	8,118	-	8,118	2,119	- Tab C-13, Schedule 38
8							
9	Taxable Income After Tax	$79,333	$51,167	$36,627	$87,794	$8,461	
10							
11		28.500%	26.500%	26.500%	26.500%	-2.000%	
12	1 - Current Income Tax Rate	71.500%	73.50%	73.500%	73.500%	2.000%	
13							
14	Taxable Income	$110,955	$69,615	$49,833	$119,448	$8,493	
15							
16	**Total Income Tax**	$31,622	$18,448	$13,206	$31,654	$32	(X-Ref - Tab C-13, Schedule 5)
17							

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Existing 2009 Rates	2010 Adjustments	2010 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,215,664	$3,317,590	$0	$3,317,590	$101,926	- Tab C-13, Schedule 45
2	Adjustment - CPCNs	12,879	-	-	-	(12,879)	- Tab C-13, Schedule 43
3	Gas Plant in Service, Ending	3,317,590	3,449,336	-	3,449,336	131,746	- Tab C-13, Schedule 45
4							
5	Accumulated Depreciation Beginning - Plant	($743,486)	($779,187)	$0	($779,187)	($35,701)	- Tab C-13, Schedule 49
6	Accumulated Depreciation Ending - Plant	(779,187)	(840,835)	-	(840,835)	(61,648)	- Tab C-13, Schedule 49
7							
8	CIAC, Beginning	($161,636)	($176,845)	$0	($176,845)	($15,209)	- Tab C-13, Schedule 52
9	CIAC, Ending	(176,845)	(183,817)	-	(183,817)	(6,972)	- Tab C-13, Schedule 52
10							
11	Accumulated Amortization Beginning - CIAC	$45,381	$44,146	$0	$44,146	($1,235)	- Tab C-13, Schedule 52
12	Accumulated Amortization Ending - CIAC	44,146	47,061	-	47,061	2,915	- Tab C-13, Schedule 52
13							
14	Net Plant in Service, Mid-Year	$2,387,253	$2,438,725	$0	$2,438,725	$51,472	
15							
16							
17	Adjustment to 13-Month Average	(10,554)	13,537	-	13,537	24,091	
18	Work in Progress, No AFUDC	15,627	15,627	-	15,627	-	
19	Unamortized Deferred Charges	(66,709)	(27,015)	-	(27,015)	39,694	- Tab C-13, Schedule 54
20	Cash Working Capital	(27,183)	(7,178)	400	(6,778)	20,405	- Tab C-13, Schedule 56
21	Other Working Capital (incl. Construction Advances)	115,701	103,439	-	103,439	(12,262)	- Tab C-13, Schedule 56
22	Future Income Taxes Regulatory Asset	278,048	284,455	-	284,455	6,407	- Tab C-13, Schedule 61
23	Future Income Taxes Regulatory Liability	(278,048)	(284,455)	-	(284,455)	(6,407)	- Tab C-13, Schedule 61
24	LILO Benefit	(1,814)	(1,648)	-	(1,648)	166	
25	**Utility Rate Base**	$2,412,321	$2,535,487	$400	$2,535,887	$123,566	(X-Ref - Tab C-13, Schedule 10)

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Existing 2009 Rates	2011 Adjustments	2011 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,317,590	$3,449,336	$0	$3,449,336	$131,746	- Tab C-13, Schedule 47
2	Adjustment - CPCNs		-	-	-	-	
3	Gas Plant in Service, Ending	3,449,336	3,535,828	-	3,535,828	86,492	- Tab C-13, Schedule 47
4							
5	Accumulated Depreciation Beginning - Plant	($779,187)	($840,835)	$0	($840,835)	($61,648)	- Tab C-13, Schedule 51
6	Accumulated Depreciation Ending - Plant	(840,835)	(899,386)	-	(899,386)	(58,551)	- Tab C-13, Schedule 51
7							
8	CIAC, Beginning	($176,845)	($183,817)	$0	($183,817)	($6,972)	- Tab C-13, Schedule 53
9	CIAC, Ending	(183,817)	(194,646)	-	(194,646)	(10,829)	- Tab C-13, Schedule 53
10							
11	Accumulated Amortization Beginning - CIAC	$44,146	$47,061	$0	$47,061	$2,915	- Tab C-13, Schedule 53
12	Accumulated Amortization Ending - CIAC	47,061	50,241	-	50,241	3,180	- Tab C-13, Schedule 53
13							
14	Net Plant in Service, Mid-Year	$2,438,725	$2,481,891	$0	$2,481,891	$43,167	
15							
16							
17	Adjustment to 13-Month Average	13,537	-	-	-	(13,537)	
18	Work in Progress, No AFUDC	15,627	15,627	-	15,627	-	
19	Unamortized Deferred Charges	(27,015)	10,347	-	10,347	37,362	- Tab C-13, Schedule 55
20	Cash Working Capital	(6,778)	(6,560)	427	(6,133)	645	- Tab C-13, Schedule 57
21	Other Working Capital (incl. Construction Advances)	103,439	120,091	-	120,091	16,652	- Tab C-13, Schedule 57
22	Future Income Taxes Regulatory Asset	284,455	292,155	-	292,155	7,700	- Tab C-13, Schedule 61
23	Future Income Taxes Regulatory Liability	(284,455)	(292,155)	-	(292,155)		- Tab C-13, Schedule 61
24	LILO Benefit	(1,648)	(1,482)	-	(1,482)	166	
25	**Utility Rate Base**	$2,535,887	$2,619,914	$427	$2,620,341	$92,154	(X-Ref - Tab C-13, Schedule 11)

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Reference	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2010 AT 2009 RATES							
2	Long-Term Debt	- Tab C-13, Schedule 64		$1,580,370	62.33%	6.868%	4.28%	
3	Unfunded Debt			67,443	2.66%	2.250%	0.06%	
4	Preference Shares			-	0.00%	0.000%	0.00%	
5	Common Equity			887,674	35.01%	6.227%	2.18%	
6								
7		- Tab C-13, Schedule 8		$2,535,487	100.00%		6.52%	
8								
9	2010 REVISED RATES							
10	Long-Term Debt	- Tab C-13, Schedule 64		$1,580,370	62.32%	6.868%	4.28%	$108,533
11	Unfunded Debt		$67,443					
12	Adjustment, Revised Rates		260	67,703	2.67%	2.250%	0.06%	1,523
13	Preference Shares			-	0.00%	0.000%	0.00%	-
14	Common Equity			887,814	35.01%	8.470%	2.97%	75,198
15		(X-Ref - Tab C-13, Schedule 4)						
16		- Tab C-13, Schedule 8		$2,535,887	100.00%		7.31%	$185,254

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Reference	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2011 AT 2009 RATES							
2	Long-Term Debt	- Tab C-13, Schedule 65		$1,631,277	62.26%	6.878%	4.28%	
3	Unfunded Debt			71,405	2.73%	4.500%	0.12%	
4	Preference Shares			-	0.00%	0.000%	0.00%	
5	Common Equity			917,232	35.01%	4.470%	1.57%	
6								
7		- Tab C-13, Schedule 9		$2,619,914	100.00%		5.97%	
8								
9	2011 REVISED RATES							
10	Long-Term Debt	- Tab C-13, Schedule 64		$1,631,277	62.25%	6.878%	4.28%	$112,204
11	Unfunded Debt		$71,405					
12	Adjustment, Revised Rates		278	71,683	2.74%	4.500%	0.12%	3,226
13	Preference Shares			-	0.00%	0.000%	0.00%	-
14	Common Equity			917,381	35.01%	8.470%	2.97%	77,702
15		(X-Ref - Tab C-13, Schedule 5)						
16		- Tab C-13, Schedule 9		$2,620,341	100.00%		7.37%	$193,132

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Existing 2009 Rates	2010 ----Revised Rates----- Revised Revenue	2010 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	115,723	112,423	-	112,423	(3,300)	- Tab C-13, Schedule 14
3	Transportation	89,214	88,255	-	88,255	(959)	- Tab C-13, Schedule 14
4		204,937	200,678	-	200,678	(4,259)	
5							
6	Average Rate per GJ						
7	Sales	$11.902	$12.583	$0.000	$12.801	$0.899	
8	Transportation	$0.830	$0.831	$0.000	$0.869	$0.039	
9	Average	$7.000	$7.415	$0.000	$7.554	$0.554	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,377,376	$1,414,636	$0	$1,414,636	$37,260	- Tab C-13, Schedule 16
13	- Increase / (Decrease)	-	-	24,497	24,497	24,497	- Tab C-13, Schedule 22
14							
15	Transportation - Existing Rates	74,087	73,362	-	73,362	(725)	- Tab C-13, Schedule 16
16	- Increase / (Decrease)	-		3,368	3,368	3,368	- Tab C-13, Schedule 22
17	**Total**	1,434,459	1,487,998	27,865	1,515,863	64,400	
18							
19	Cost of Gas Sold (Including Gas Lost)	931,546	975,597	-	975,597	44,051	- Tab C-13, Schedule 19
20							
21	**Gross Margin**	502,913	512,401	27,865	540,266	20,349	
22							
23	Operation and Maintenance	165,162	192,823	-	192,823	27,661	- Tab C-13, Schedule 28
24	Vehicle Lease	1,804	-	-	-	(1,804)	
25	Property and Sundry Taxes	47,593	49,193	-	49,193	1,600	- Tab C-13, Schedule 31
26	Depreciation and Amortization	79,725	103,796	-	103,796	24,071	- Tab C-13, Schedule 33
27	Other Operating Revenue	(20,906)	(22,422)	-	(22,422)	(1,516)	- Tab C-13, Schedule 26
28		273,378	323,390	-	323,390	50,012	
29	Utility Income Before Income Taxes	229,535	189,011	27,865	216,876	(12,659)	
30							
31	Income Taxes	23,010	23,683	7,939	31,622	8,612	- Tab C-13, Schedule 35
32							
33	**EARNED RETURN**	$206,525	$165,328	$19,926	$185,254	($21,271)	- Tab C-13, Schedule 10
34							
35							
36	**UTILITY RATE BASE**	$2,412,321	$2,535,487	$400	$2,535,887	$123,566	- Tab C-13, Schedule 8
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	8.56%	6.52%		7.31%	-1.25%	- Tab C-13, Schedule 10

TERASEN GAS INC. June 12, 2009 Advance Materials Section C Tab 13 Schedule 13

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars (1)	2010 FORECAST (2)	2011 Existing 2009 Rates (3)	2011 Revised Rates Revised Revenue (4)	2011 Revised Rates Total (5)	Change (6)	Reference (7)
1	ENERGY VOLUMES (TJ)						
2	Sales	112,423	112,326	-	112,326	(97)	- Tab C-13, Schedule 15
3	Transportation	88,255	88,438	-	88,438	183	- Tab C-13, Schedule 15
4		200,678	200,764	-	200,764	86	
5							
6	Average Rate per GJ						
7	Sales	$12.801	$12.607	$0.000	$12.997	$0.196	
8	Transportation	$0.869	$0.830	$0.000	$0.898	$0.029	
9	Average	$7.554	$7.419	$0.000	$7.668	$0.114	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,414,636	$1,416,102	$0	$1,416,102	$1,466	- Tab C-13, Schedule 17
13	- Increase / (Decrease)	24,497	-	43,822	43,822	19,325	- Tab C-13, Schedule 24
14							
15	Transportation - Existing Rates	73,362	73,417	-	73,417	55	- Tab C-13, Schedule 17
16	- Increase / (Decrease)	3,368		6,024	6,024	2,656	- Tab C-13, Schedule 24
17	**Total**	1,515,863	1,489,519	49,846	1,539,365	23,502	
18							
19	Cost of Gas Sold (Including Gas Lost)	975,597	976,614	-	976,614	1,017	- Tab C-13, Schedule 21
20							
21	**Gross Margin**	540,266	512,905	49,846	562,751	22,485	
22							
23	Operation and Maintenance	192,823	201,617	-	201,617	8,794	- Tab C-13, Schedule 28
24	Vehicle Lease	-	-	-	-	-	
25	Property and Sundry Taxes	49,193	50,211	-	50,211	1,018	- Tab C-13, Schedule 32
26	Depreciation and Amortization	103,796	110,496	-	110,496	6,700	- Tab C-13, Schedule 34
27	Other Operating Revenue	(22,422)	(24,359)	-	(24,359)	(1,937)	- Tab C-13, Schedule 27
28		323,390	337,965	-	337,965	14,575	
29	Utility Income Before Income Taxes	216,876	174,940	49,846	224,786	7,910	
30							
31	Income Taxes	31,622	18,448	13,206	31,654	32	- Tab C-13, Schedule 36
32							
33	**EARNED RETURN**	$185,254	$156,492	$36,640	$193,132	$7,878	- Tab C-13, Schedule 11
34							
35							
36	**UTILITY RATE BASE**	$2,535,887	$2,619,914	$427	$2,620,341	$84,454	- Tab C-13, Schedule 9
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.31%	5.97%		7.37%	0.07%	- Tab C-13, Schedule 11

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2010

Line No.	Particulars	2009 PROJECTION	2010 Terajoules Core and Non-Core	2010 Terajoules Bypass and Special Rates	2010 Terajoules Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	71,031.7	67,829.2	0.0	67,829.2	(3,202.5)	
3	Schedule 2 - Small Commercial	24,484.9	24,374.3		24,374.3	(110.6)	
4	Schedule 3 - Large Commercial	16,752.0	16,818.6		16,818.6	66.6	
5							
6	Schedules 1, 2 and 3	112,268.6	109,022.1	0.0	109,022.1	(3,246.5)	
7							
8	Schedule 4 - Seasonal	184.6	184.6		184.6	0.0	
9	Schedule 5 - General Firm	3,151.8	3,098.5		3,098.5	(53.3)	
10							
11	Industrials						
12	Schedule 7 - Interruptible	13.7	14.2		14.2	0.5	
13							
14	Schedule 6 - N G V Fuel - Stations	103.8	103.8		103.8	0.0	
15							
16	Total Sales	115,722.5	112,423.2	0.0	112,423.2	(3,299.3)	(X-Ref - Tab C-13, Schedule 4)
17							
18	**TRANSPORTATION SERVICE**						
19	Schedule 22 - Firm Service	14,381.3	7,136.8	5,953.6	13,090.4	(1,290.9)	
20	- Interruptible Service	11,950.8	11,849.7	0.0	11,849.7	(101.1)	
21	Byron Creek (aka Fording Coal Mountain)	126.9		125.8	125.8	(1.1)	
22	Burrard Thermal - Firm	2,343.9		2,343.9	2,343.9	0.0	
23	TGVI - Firm	35,328.2		36,368.3	36,368.3	1,040.1	
24	Schedule 23 - Large Commercial	6,309.5	6,134.0		6,134.0	(175.5)	
25	Schedule 25 - Firm Service	13,432.1	12,466.5	693.1	13,159.6	(272.5)	
26	Schedule 27 - Interruptible Service	5,341.6	5,183.5		5,183.5	(158.1)	
22							
23	Total Transportation Service	89,214.3	42,770.5	45,484.7	88,255.2	(959.1)	(X-Ref - Tab C-13, Schedule 4)
24							
25	**TOTAL SALES AND TRANSPORTATION SERVICES**	204,936.8	155,193.7	45,484.7	200,678.4	(4,258.4)	(X-Ref - Tab C-13, Schedule 23)

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2011

Line No.	Particulars	2010 FORECAST	2011 Terajoules Core and Non-Core	2011 Terajoules Bypass and Special Rates	2011 Terajoules Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	67,829.2	67,190.5	0.0	67,190.5	(638.7)	
3	Schedule 2 - Small Commercial	24,374.3	24,603.1		24,603.1	228.8	
4	Schedule 3 - Large Commercial	16,818.6	17,168.5		17,168.5	349.9	
5							
6	Schedules 1, 2 and 3	109,022.1	108,962.1	0.0	108,962.1	(60.0)	
7							
8	Schedule 4 - Seasonal	184.6	184.6		184.6	0.0	
9	Schedule 5 - General Firm	3,098.5	3,061.2		3,061.2	(37.3)	
10							
11	Industrials						
12	Schedule 7 - Interruptible	14.2	14.2		14.2	0.0	
13							
14	Schedule 6 - N G V Fuel - Stations	103.8	103.8		103.8	0.0	
15							
16	Total Sales	112,423.2	112,325.9	0.0	112,325.9	(97.3)	(X-Ref - Tab C-13, Schedule 5)
17							
18	**TRANSPORTATION SERVICE**						
19	Schedule 22 - Firm Service	13,090.4	7,136.8	5,953.6	13,090.4	0.0	
20	- Interruptible Service	11,849.7	11,830.5	0.0	11,830.5	(19.2)	
21	Byron Creek (aka Fording Coal Mountain)	125.8		125.8	125.8	0.0	
22	Burrard Thermal - Firm	2,343.9		2,343.9	2,343.9	0.0	
23	TGVI - Firm	36,368.3		36,596.4	36,596.4	228.1	
24	Schedule 23 - Large Commercial	6,134.0	6,177.2		6,177.2	43.2	
25	Schedule 25 - Firm Service	13,159.6	12,408.9	693.1	13,102.0	(57.6)	
26	Schedule 27 - Interruptible Service	5,183.5	5,171.9		5,171.9	(11.6)	
22							
23	Total Transportation Service	88,255.2	42,725.3	45,712.8	88,438.1	182.9	(X-Ref - Tab C-13, Schedule 5)
24							
25	**TOTAL SALES AND TRANSPORTATION SERVICES**	200,678.4	155,051.2	45,712.8	200,764.0	85.6	(X-Ref - Tab C-13, Schedule 25)

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Gas Sales Revenue At Existing 2009 Rates: Core and Non-Core	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**Core Sales**						
2	Schedule 1 - Residential	$883,495	$897,420	$0	$897,420	$13,925	
3	Schedule 2 - Small Commercial	283,824	297,556		297,556	13,732	
4	Schedule 3 - Large Commercial	177,855	189,604		189,604	11,750	
5	Schedules 1, 2 and 3	1,345,174	1,384,580	-	1,384,580	39,407	
6							
7	Schedule 4 - Seasonal	1,477	1,477	-	1,477	-	
8	Schedule 5 - General Firm	29,522	27,404		27,404	(2,118)	
9		31,000	28,881	-	28,881	(2,118)	
10	Industrials						
11	Interruptible - Schedule 7	127	130	-	130	3	
12							
13	N G V Fuel - Stations - Schedule 6	1,076	1,044		1,044	(32)	
14							
15	Total Core Sales	1,377,376	1,414,636	-	1,414,636	37,260	(X-Ref - Tab C-13, Schedule 4)
16							(X-Ref - Tab C-13, Schedule 12)
17	**Transportation Service**						
18	Schedule 22 - Firm Service	6,411	5,110	1,270	6,380	(31)	
19	- Interruptible Service	9,819	9,743	-	9,743	(76)	
20	Byron Creek (aka Fording Coal Mountain)	53		53	53	-	
21	Burrard Thermal - Firm	9,953		9,996	9,996	43	
22	TGVI - Firm	-		-	-	-	
23	Schedule 23 - Large Commercial	16,777	16,411	-	16,411	(367)	
24	Schedule 25 - Firm Service	24,648	23,747	762	24,509	(138)	
25	Schedule 27 - Interruptible Service	6,426	6,270	-	6,270	(157)	
26	Total T-Service	74,087	61,280	12,081	73,362	(725)	(X-Ref - Tab C-13, Schedule 4)
27							(X-Ref - Tab C-13, Schedule 12)
28	TOTAL SALES AND TRANSPORTATION SERVICE	$1,451,464	$1,475,916	$12,081	$1,487,998	$36,534	(X-Ref - Tab C-13, Schedule 23)

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Gas Sales Revenue At Existing 2009 Rates: Core and Non-Core	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**Core Sales**						
2	Schedule 1 - Residential	$897,420	$891,764	$0	$891,764	($5,656)	
3	Schedule 2 - Small Commercial	297,556	300,831		300,831	3,275	
4	Schedule 3 - Large Commercial	189,604	193,720		193,720	4,116	
5	Schedules 1, 2 and 3	1,384,580	1,386,315	-	1,386,315	1,735	
6							
7	Schedule 4 - Seasonal	1,477	1,477	-	1,477	-	
8	Schedule 5 - General Firm	27,404	27,135		27,135	(268)	
9		28,881	28,613	-	28,613	(268)	
10	Industrials						
11	Interruptible - Schedule 7	130	130	-	130	-	
12							
13	N G V Fuel - Stations - Schedule 6	1,044	1,044		1,044	-	
14							
15	Total Core Sales	1,414,636	1,416,102	-	1,416,102	1,466	- Tab C-13, Schedule 5
16							(X-Ref - Tab C-13, Schedule 13)
17	**Transportation Service**						
18	Schedule 22 - Firm Service	6,380	5,110	1,270	6,380	-	
19	- Interruptible Service	9,743	9,729	-	9,729	(14)	
20	Byron Creek (aka Fording Coal Mountain)	53		53	53	-	
21	Burrard Thermal - Firm	9,996		9,996	9,996	-	
22	TGVI - Firm	-		-	-	-	
23	Schedule 23 - Large Commercial	16,411	16,525	-	16,525	115	
24	Schedule 25 - Firm Service	24,509	23,713	762	24,475	(34)	
25	Schedule 27 - Interruptible Service	6,270	6,258	-	6,258	(11)	
26	Total T-Service	73,362	61,336	12,081	73,417	55	- Tab C-13, Schedule 5
27							(X-Ref - Tab C-13, Schedule 13)
28	TOTAL SALES AND TRANSPORTATION SERVICE	$1,487,998	$1,477,438	$12,081	$1,489,519	$1,521	(X-Ref - Tab C-13, Schedule 25)

COST OF GAS BY RATE SCHEDULE - Summary by Service Area (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2010

Line No.	Particulars	Lower Mainland Energy TJ	Lower Mainland Unit Cost $/GJ	Lower Mainland Cost of Gas ($000s)	Inland Including Revelstoke Energy TJ	Inland Including Revelstoke Unit Cost $/GJ	Inland Including Revelstoke Cost of Gas ($000s)	Columbia Energy TJ	Columbia Unit Cost $/GJ	Columbia Cost of Gas ($000s)	Total Cost of Gas ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**Non-Bypass CORE AND NON-CORE**										
2	Core Sales										
3	Schedule 1 - Residential	50,837.8	$8.830	$448,888	15,349.2	$8.325	$127,783	1,642.2	$8.393	$13,783	$590,454
4	Schedule 2 - Small Commercial	17,866.8	8.972	160,297	5,791.0	8.449	48,931	716.5	8.554	6,129	215,357
5	Schedule 3 - Large Commercial	13,802.1	8.756	120,855	2,703.0	8.260	22,327	313.5	8.140	2,552	145,734
6	Schedules 1, 2 and 3	82,506.7		730,040	23,843.2		199,041	2,672.2		22,464	951,545
7											
8	Schedule 4 - Seasonal	87.8	6.701	588	96.8	6.622	641	-	-	-	1,229
9	Schedule 5 - General Firm	2,658.1	6.632	17,629	402.5	6.606	2,659	37.9	6.665	253	20,541
10											
11	Industrials										
12	Interruptible - Schedule 7	9.8	6.663	65	4.4	6.818	30	-	-	-	95
13											
14	N G V Fuel - Stations - Schedule 6	92.0	6.447	593	11.8	6.356	75	-	-	-	668
15											
16	Total Core Sales	85,354.4		748,915	24,358.7		202,446	2,710.1		22,717	974,078
17											
18	Transportation Service										
19	Schedule 22 - Firm Service	-	-	-	4,675.8	0.017	79	2,461.0	0.082	201	280
20	- Interruptible Service	11,579.4	0.007	79	228.9	0.406	93	41.4	-	-	172
21	Schedule 23 - Large Commercial	4,950.9	0.008	40	1,124.1	0.016	18	59.0	0.080	5	63
22	Schedule 25 - Firm Service	9,256.8	0.008	74	2,966.9	0.016	48	242.8	0.080	20	142
23	Schedule 27 - Interruptible Service	4,532.4	0.008	36	635.7	0.016	10	15.4	-	-	46
24	Total T-Service	30,319.5		229	9,631.4		248	2,819.6		226	703
25	**Total Non-Bypass Sales and Transportation Service**										
26	**Cost of Gas Sold**	115,673.9		$749,144	33,990.1		$202,694	5,529.7		$22,943	$974,781

COST OF GAS BY RATE SCHEDULE - Summary by Service Area (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2010

Line No.	Particulars	Lower Mainland Energy TJ	Lower Mainland Unit Cost $/GJ	Lower Mainland Cost of Gas ($000s)	Inland Including Revelstoke Energy TJ	Inland Unit Cost $/GJ	Inland Cost of Gas ($000s)	Columbia Energy TJ	Columbia Unit Cost $/GJ	Columbia Cost of Gas ($000s)	Total Cost of Gas ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	-	-	14	5,780.0	-	-	173.6	0.046	8	22
4	- Interruptible Service	-	-	-	-	-	-	-	-	-	-
5	Byron Creek (aka Fording Coal Mountain)	-	-	-	-	-	-	125.8	0.049	6	6
6	Burrard Thermal - Firm	2,343.9	0.020	47	-	-	-	-	-	-	47
7	TGVI - Firm	36,368.3	0.020	730	-	-	-	-	-	-	730
8	Schedule 23 - Large Commercial				-	-	-				-
9	Schedule 25 - Firm Service	-	-	-	693.1	0.016	11	-	-	-	11
10	Schedule 27 - Interruptible Service				-	-	-				-
11	**Total Bypass and Spec. Rates T-Svc**	38,712.2		791	6,473.1		11	299.4		14	816
12											
13	**Total Non-Bypass and Bypass Sales and Transportation Service**										
14	**Cost of Gas Sold**	154,386.1		$749,935	40,463.2		$202,705	5,829.1		$22,957	$975,597

(X-Ref - Tab C-13, Schedule 12) , (X-Ref - Tab C-13, Schedule 4)

COST OF GAS BY RATE SCHEDULE - Summary by Service Area (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2011

Line No.	Particulars	Lower Mainland Energy TJ	Lower Mainland Unit Cost $/GJ	Lower Mainland Cost of Gas ($000s)	Inland Including Revelstoke Energy TJ	Inland Including Revelstoke Unit Cost $/GJ	Inland Including Revelstoke Cost of Gas ($000s)	Columbia Energy TJ	Columbia Unit Cost $/GJ	Columbia Cost of Gas ($000s)	Total Cost of Gas ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**Non-Bypass CORE AND NON-CORE**										
2	Core Sales										
3	Schedule 1 - Residential	50,359.0	$8.846	$445,483	15,198.8	$8.342	$126,792	1,632.7	$8.410	$13,731	$586,006
4	Schedule 2 - Small Commercial	18,027.1	8.991	162,072	5,851.0	8.471	49,566	725.0	8.580	6,221	217,859
5	Schedule 3 - Large Commercial	14,042.4	8.770	123,157	2,801.4	8.259	23,136	324.7	8.149	2,646	148,939
6	Schedules 1, 2 and 3	82,428.5		730,712	23,851.2		199,494	2,682.4		22,598	952,804
7											
8	Schedule 4 - Seasonal	87.8	6.701	588	96.8	6.622	641	-	-	-	1,229
9	Schedule 5 - General Firm	2,625.6	6.632	17,413	398.2	6.605	2,630	37.4	6.701	251	20,294
10											
11	Industrials										
12	Interruptible - Schedule 7	9.8	6.663	65	4.4	6.818	30	-	-	-	95
13											
14	N G V Fuel - Stations - Schedule 6	92.0	6.447	593	11.8	6.356	75	-	-	-	668
15											
16	Total Core Sales	85,243.7		749,371	24,362.4		202,870	2,719.8		22,849	975,090
17											
18	Transportation Service										
19	Schedule 22 - Firm Service	-	-	-	4,675.8	0.017	79	2,461.0	0.082	201	280
20	- Interruptible Service	11,560.2	0.007	79	228.9	0.406	93	41.4	-	-	172
21	Schedule 23 - Large Commercial	4,974.0	0.008	40	1,144.2	0.016	18	59.0	0.080	5	63
22	Schedule 25 - Firm Service	9,204.5	0.008	74	2,961.6	0.016	48	242.8	0.080	20	142
23	Schedule 27 - Interruptible Service	4,522.7	0.008	36	633.8	0.016	10	15.4	-	-	46
24	Total T-Service	30,261.4		229	9,644.3		248	2,819.6		226	703
25	**Total Non-Bypass Sales and Transportation Service**										
26	**Cost of Gas Sold**	115,505.1		$749,600	34,006.7		$203,118	5,539.4		$23,075	$975,793

COST OF GAS BY RATE SCHEDULE - Summary by Service Area (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2011

Line No.	Particulars	Lower Mainland Energy TJ	Lower Mainland Unit Cost $/GJ	Lower Mainland Cost of Gas ($000s)	Inland Including Revelstoke Energy TJ	Inland Including Revelstoke Unit Cost $/GJ	Inland Including Revelstoke Cost of Gas ($000s)	Columbia Energy TJ	Columbia Unit Cost $/GJ	Columbia Cost of Gas ($000s)	Total Cost of Gas ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	-	-	14	5,780.0	-	-	173.6	0.058	10	24
4	- Interruptible Service	-	-	-	-	-	-	-	-	-	-
5	Byron Creek (aka Fording Coal Mountain)	-	-	-	-	-	-	125.8	0.035	4	4
6	Burrard Thermal - Firm	2,343.9	0.020	47	-	-	-	-	-	-	47
7	TGVI - Firm	36,596.4	0.020	735	-	-	-	-	-	-	735
8	Schedule 23 - Large Commercial				-	-	-				-
9	Schedule 25 - Firm Service	-	-	-	693.1	0.016	11	-	-	-	11
10	Schedule 27 - Interruptible Service				-	-	-				-
11	**Total Bypass and Spec. Rates T-Svc**	38,940.3		796	6,473.1		11	299.4		14	821
12											
13	**Total Non-Bypass and Bypass Sales and Transportation Service**										
14	**Cost of Gas Sold**	154,445.4		$750,396	40,479.8		$203,129	5,838.8		$23,089	$976,614

(X-Ref - Tab C-13, Schedule 13) , (X-Ref - Tab C-13, Schedule 5)

REVENUE UNDER EXISTING 2009 RATES AND REVISED 2010 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars		Revenue -- At Existing 2009 Rates --		Gross Margin -- At Existing 2009 Rates --		Effective Increase / (Decrease) 5.56% of Margin			Revenue ---- Revised Rates ----	
		Terajoules	Average $/GJ	Revenue ($000s)	Average $/GJ	Margin ($000s)	$/GJ	Revenue ($000s)	Average Number of Customers	Average $/GJ	Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Core Sales										
3	Schedule 1 - Residential	67,829.2	$13.231	$897,420	$4.526	$306,966	$0.252	$17,067	756,017	$13.483	$914,487
4	Schedule 2 - Small Commercial	24,374.3	12.208	297,556	3.372	82,200	0.188	4,571	76,536	12.396	302,127
5	Schedule 3 - Large Commercial	16,818.6	11.273	189,604	2.608	43,870	0.145	2,440	5,022	11.418	192,044
6	Total Schedules 1 , 2 and 3	109,022.1		1,384,580		433,036		24,078	837,575		1,408,658
7											
8	Schedule 4 - Seasonal Service	184.6	8.003	1,477	1.343	248	0.076	14	16	8.079	1,491
9	Schedule 5 - General Firm Service	3,098.5	8.844	27,404	2.215	6,864	0.123	382	283	8.967	27,786
10											
11	Industrials										
12	Schedule 7 - Interruptible	14.2	9.176	130	2.486	35	0.141	2	2	9.317	132
13											
14	Schedule 6 - N G V Fuel - Stations	103.8	10.062	1,044	3.628	377	0.202	21	32	10.264	1,065
15											
16	Total Core Sales	112,423.2		1,414,636		440,559		24,497	837,908		1,439,133
17											
18	Transportation Service										
19	Schedule 22 - Firm Service	7,136.8	0.716	5,110	0.677	4,831	0.038	269	13	0.754	5,379
20	- Interruptible Service	11,849.7	0.822	9,743	0.808	9,571	0.045	532	22	0.867	10,275
21	Schedule 23 - Large Commercial	6,134.0	2.675	16,411	2.665	16,348	0.148	909	1,309	2.823	17,320
22	Schedule 25 - Firm Service	12,466.5	1.905	23,747	1.894	23,606	0.105	1,312	579	2.010	25,059
23	Schedule 27 - Interruptible Service	5,183.5	1.210	6,270	1.201	6,223	0.067	346	99	1.277	6,616
24											
25	Total T-Service	42,770.5		61,280		60,579		3,368	2,022		64,648
26											
27	Total Non-Bypass Sales & Transportation Service	155,193.7		$1,475,916		$501,138		$27,865	839,930		$1,503,781
28		(X-Ref - Tab C-13, Schedule 14)		(X-Ref - Tab C-13, Schedule 16)			(X-Ref - Tab C-13, Schedule 2)				

REVENUE UNDER EXISTING 2009 RATES AND REVISED 2010 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

			Revenue -- At Existing 2009 Rates --		Gross Margin -- At Existing 2009 Rates --		Increase / (Decrease) 5.56% of Margin			Revenue ---- Revised Rates ----	
Line No.	Particulars	Terajoules	Average $/GJ	Revenue ($000)	Average $/GJ	Margin ($000s)	$/GJ	Revenue ($000)	Average Number of Customers	Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	5,953.6	0.213	1,270	0.210	1,247	-	-	8	0.213	1,270
4	- Interruptible Service	-	-	-	-	-	-	-	1	-	-
5	Byron Creek (aka Fording Coal Mountain)	125.8	0.422	53	0.374	47	-	-	1	0.422	53
6	Burrard Thermal - Firm	2,343.9	4.265	9,996	4.245	9,949	-	-	1		9,996
7	TGVI - Firm	36,368.3	-	-	-	-	-	-	1	-	-
8	Schedule 23 - Large Commercial	-		-		-		-	-	-	-
9	Schedule 25 - Firm Service	693.1	1.100	762	1.084	751	-	-	7	1.100	762
10	Schedule 27 - Interruptible Service	-		-		-		-	-	-	-
11	Total Bypass and Spec. Rates T-Svc	45,484.7		12,081		11,995		-	19		12,081
12											
13	Total Bypass Sales and										
14	Transportation Service	45,484.7		12,081		11,995		-	19		12,081
15											
16	TOTAL NON-BYPASS AND BYPASS SALES AND										
17	TRANSPORTATION SERVICE	200,678.4		$1,487,998		$513,132		$27,865	839,949		$1,515,863
18		(X-Ref - Tab C-13, Schedule 14)		(X-Ref - Tab C-13, Schedule 16)			(X-Ref - Tab C-13, Schedule 2)				

REVENUE UNDER EXISTING 2009 RATES AND REVISED 2011 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2009 Rates -- Average $/GJ	Revenue ($000)	Gross Margin -- At Existing 2009 Rates -- Average $/GJ	Margin ($000s)	Effective Increase / (Decrease) 9.94% of Margin $/GJ	Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Core Sales										
3	Schedule 1 - Residential	67,190.5	$13.272	$891,764	$4.551	$305,757	$0.452	$30,383	760,873	$13.724	$922,147
4	Schedule 2 - Small Commercial	24,603.1	12.227	300,831	3.372	82,972	0.335	8,245	77,252	12.562	309,076
5	Schedule 3 - Large Commercial	17,168.5	11.283	193,720	2.608	44,781	0.259	4,450	5,126	11.542	198,170
6	Total Schedules 1 , 2 and 3	108,962.1		1,386,315		433,510		43,078	843,250		1,429,393
7											
8	Schedule 4 - Seasonal Service	184.6	8.0030	1,477	1.3430	248	0.1350	25	16	8.138	1,502
9	Schedule 5 - General Firm Service	3,061.2	8.8640	27,135	2.2350	6,841	0.2220	679	283	9.086	27,814
10											
11	Industrials										
12	Schedule 7 - Interruptible	14.2	9.1760	130	2.4860	35	0.2110	3	2	9.387	133
13											
14	Schedule 6 - N G V Fuel - Stations	103.8	10.0620	1,044	3.6280	377	0.3560	37	32	10.418	1,081
15											
16	Total Core Sales	112,325.9		1,416,102		441,011		43,822	843,583		1,459,924
17											
18	Transportation Service										
19	Schedule 22 - Firm Service	7,136.8	0.7160	5,110	0.6770	4,831	0.0670	480	13	0.783	5,590
20	- Interruptible Service	11,830.5	0.8220	9,729	0.8080	9,557	0.0800	949	22	0.902	10,678
21	Schedule 23 - Large Commercial	6,177.2	2.6750	16,525	2.6650	16,462	0.2650	1,636	1,318	2.940	18,161
22	Schedule 25 - Firm Service	12,408.9	1.9110	23,713	1.9000	23,572	0.1890	2,342	579	2.100	26,055
23	Schedule 27 - Interruptible Service	5,171.9	1.2100	6,258	1.2010	6,212	0.1190	617	99	1.329	6,875
24											
25	Total T-Service	42,725.3		61,336		60,634		6,024	2,031		67,360
26											
27	Total Non-Bypass Sales & Transportation Service	155,051.2		$1,477,438		$501,645		$49,846	845,614		$1,527,284
28		(X-Ref - Tab C-13, Schedule 15)		(X-Ref - Tab C-13, Schedule 17)				(X-Ref - Tab C-13, Schedule 3)			

REVENUE UNDER EXISTING 2009 RATES AND REVISED 2011 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2009 Rates -- Average $/GJ	Revenue -- At Existing 2009 Rates -- Revenue ($000)	Gross Margin -- At Existing 2009 Rates -- Average $/GJ	Gross Margin -- At Existing 2009 Rates -- Margin ($000s)	Increase / (Decrease) 9.94% of Margin $/GJ	Increase / (Decrease) 9.94% of Margin Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ---- Revised Rates ---- Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	5,953.6	0.2130	1,270	0.2092	1,246	-	-	8	0.2130	1,270
4	- Interruptible Service	-	-	-	-	-	-	-	1	-	-
5	Byron Creek (aka Fording Coal Mountain)	125.8	0.4220	53	0.3872	49	-	-	1	0.4220	53
6	Burrard Thermal - Firm	2,343.9	4.2650	9,996	4.2446	9,949	-	-	1	4.2650	9,996
7	TGVI - Firm	36,596.4	-	-	-	-	-	-	1	-	-
8	Schedule 23 - Large Commercial	-		-		-		-	-	-	-
9	Schedule 25 - Firm Service	693.1	1.1000	762	1.0840	751	-	-	7	1.1000	762
10	Schedule 27 - Interruptible Service	-		-		-		-	-	-	-
11	Total Bypass and Spec. Rates T-Svc	45,712.8		12,081		11,995		-	19		12,081
12											
13	Total Bypass Sales and										
14	Transportation Service	45,712.8		12,081		11,995		-	19		12,081
15											
16	TOTAL NON-BYPASS AND BYPASS SALES AND										
17	TRANSPORTATION SERVICE	200,764.0		$1,489,519		$513,639		$49,846	845,633		$1,539,365
18		(X-Ref - Tab C-13, Schedule 15)		(X-Ref - Tab C-13, Schedule 17)				(X-Ref - Tab C-13, Schedule 3)			

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$2,879	$2,982	$103	(X-Ref - Tab C-13, Schedule 59)
4					
5	Connection Charge	3,105	2,879	(226)	(X-Ref - Tab C-13, Schedule 59)
6					
7	NSF Returned Cheque Charges	84	82	(2)	(X-Ref - Tab C-13, Schedule 59)
8					
9	Other Recoveries	68	74	6	(X-Ref - Tab C-13, Schedule 59)
10					
11	Total Other Utility Revenue	6,136	6,017	(119)	
12					
13	**Miscellaneous Revenue**				
14					
15	TGVI Wheeling Charge	3,426	3,457	31	(X-Ref - Tab C-13, Schedule 2)
16					
17	SCP Third Party Revenue	11,135	12,819	1,684	(X-Ref - Tab C-13, Schedule 2)
18					
19	TGVI SAP Lease Income	209	129	(80)	(X-Ref - Tab C-13, Schedule 59)
20					
21					
22	Total Miscellaneous	14,770	16,405	1,635	
23					(X-Ref - Tab C-13, Schedule 12)
24	**Total Other Operating Revenue**	$20,906	$22,422	$1,516	(X-Ref - Tab C-13, Schedule 4)

TERASEN GAS INC. June 12, 2009 Advance Materials Section C
Tab 13
Schedule 27

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000)

Line No.	Particulars	2010 FORECAST	2011	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$2,982	$2,987	$5	(X-Ref - Tab C-13, Schedule 59)
4					
5	Connection Charge	2,879	2,905	26	(X-Ref - Tab C-13, Schedule 59)
6					
7	NSF Returned Cheque Charges	82	82	-	(X-Ref - Tab C-13, Schedule 59)
8					
9	Other Recoveries	74	76	2	(X-Ref - Tab C-13, Schedule 59)
10					
11	Total Other Utility Revenue	6,017	6,050	33	
12					
13	**Miscellaneous Revenue**				
14					
15	TGVI Wheeling Charge	3,457	3,455	(2)	(X-Ref - Tab C-13, Schedule 3)
16					
17	SCP Third Party Revenue	12,819	14,798	1,979	(X-Ref - Tab C-13, Schedule 3)
18					
19	TGVI SAP Lease Income	129	56	(73)	(X-Ref - Tab C-13, Schedule 59)
20					
21					
22	Total Miscellaneous	16,405	18,309	1,904	
23					(X-Ref - Tab C-13, Schedule 13)
24	**Total Other Operating Revenue**	$22,422	$24,359	$1,937	(X-Ref - Tab C-13, Schedule 5)

TERASEN GAS INC

Section C
Tab 13
Schedule 28

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000)

No.	Particulars	PROJECTION 2009	FORECAST 2010	FORECAST 2011	Reference
	(1)	(2)	(3)	(4)	(5)
1	M&E Costs	$ 43,087	$ 46,479	$ 49,646	
2	COPE Costs	24,792	29,599	32,032	
3	IBEW Costs	22,301	24,870	26,559	
4					
5	**Labour Costs**	**90,179**	**100,948**	**108,237**	
6					
7	Vehicle Costs	4,626	3,111	3,084	
8	Employee Expenses	3,979	5,338	5,353	
9	Materials and Supplies	5,579	7,251	7,191	
10	Computer Costs	7,612	11,192	11,991	
11	Fees and Administration Costs	27,369	27,006	27,501	
12	Contractor Costs	58,251	62,889	64,329	
13	Facilities	11,717	13,973	14,318	
14	Recoveries & Revenue	(14,235)	(22,117)	(22,854)	
15					
16	**Non-Labour Costs**	**104,899**	**108,642**	**110,912**	
17					
18					
19	**Total Gross O&M Expenses**	**195,078**	**209,590**	**219,149**	
20					
21	Less: Vehicle Lease Reclass	(1,804)	-	-	
22	Less: Capitalized Overhead	(28,113)	(16,767)	(17,532)	
23					(X-Ref - Tab C-13, Schedule 4)
24	**Total O&M Expenses**	**$ 165,162**	**$ 192,823**	**$ 201,617**	(X-Ref - Tab C-13, Schedule 5)

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000)

No.	Particulars	Reference	PROJECTION 2009	FORECAST 2010	FORECAST 2011	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Distribution Supervision	100-11	$ 9,782	$ 10,331	$ 10,609	
2	Distribution Supervision Total	100-10	9,782	10,331	10,609	
3						
4	Operation Centre - Distribution	100-21	6,747	9,798	10,451	
5	Asset Management - Distribution	100-22	1,113	1,925	2,437	
6	Preventative Maintenance - Distribution	100-23	2,026	1,927	2,377	
7	Distribution Operations - General	100-24	4,720	5,096	5,512	
8	Emergency Management	100-25	6,582	5,240	5,488	
9	Distribution Operations Total	100-20	21,189	23,986	26,266	
10						
11	Distribution Corrective - Meters	100-31	1,176	1,433	1,524	
12	Distribution Corrective - Propane	100-32	5	5	5	
13	Distribution Corrective - Leak Repair	100-33	931	939	996	
14	Distribution Corrective - Stations	100-34	490	681	727	
15	Distribution Corrective - General	100-35	486	505	534	
16	Distribution Maintenance Total	100-30	3,089	3,562	3,785	
17						
18	**Distribution Total**	**100**	**34,060**	**37,879**	**40,660**	
19						
20	Transmission Supervision	200-11	2,448	3,079	3,161	
21	Transmission Supervision Total	200-10	2,448	3,079	3,161	
22						
23	Pipeline Operation	200-21	2,094	2,627	2,836	
24	Right of Way	200-22	1,407	1,282	1,345	
25	Compression	200-23	1,650	1,919	1,922	
26	Gas Control	200-24	2,264	2,896	3,105	
27	Transmission Pipeline Integrity Project (TPIP)	200-25	5,355	3,177	3,317	
28	Transmission Operations Total	200-20	12,771	11,902	12,525	
29						
30	Pipeline - Maintenance	200-31	167	189	194	
31	Compression - Maintenance	200-32	163	167	172	
32	TPIP - Maintenance	200-33	373	671	929	
33	Transmission Maintenance Total	200-30	702	1,027	1,295	
34						
35	**Transmission Total**	**200**	**15,921**	**16,008**	**16,980**	
36						
37	LNG Plant Operations	300-11	825	1,036	1,088	
38	LNG Plant Operations Total	300-10	825	1,036	1,088	
39	LNG Plant Maintenance	300-21	200	269	277	
40	LNG Plant Maintenance Total	300-20	200	269	277	
41						
42	**LNG Plant Total**	**300**	**1,025**	**1,305**	**1,365**	
43						
44	Measurement Operations	400-11	3,759	4,083	4,297	
45	Measurement Operations Total	400-10	3,759	4,083	4,297	
46						
47	Measurement Maintenance	400-21	1,804	2,208	2,334	
48	Measurement Maintenance Total	400-20	1,804	2,208	2,334	
49						
50	**Measurement Total**	**400**	**5,562**	**6,291**	**6,630**	

TERASEN GAS INC.

Section C
Tab 13
Schedule 30

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000)

No.	Particulars	Reference	PROJECTION 2009	FORECAST 2010	FORECAST 2011	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Facilities Management	500-10	5,580	6,277	5,968	
2	Shops & Stores	500-20	3,699	4,018	4,152	
3	Operations Engineering	500-30	6,368	8,121	8,679	
4	Property Services	500-40	988	1,174	1,307	
5	System Integrity	500-50	2,040	2,393	2,492	
6	Environmental Health & Safety	500-60	1,490	2,352	2,504	
7	Operations Governance	500-70	1,515	1,692	1,800	
8						
9	**General Operations Total**	**500**	**21,679**	**26,025**	**26,903**	
10						
11	Energy Efficiency	600-10	$ 1,624	$ -	$ -	
12	Marketing - Supervision	600-20	1,208	621	634	
13	Corporate & Marketing Communications	600-30	2,574	3,593	3,673	
14	Marketing Planning & Development	600-40	749	655	669	
15	**Marketing Total**	**600**	**6,156**	**4,868**	**4,976**	
16						
17	Customer Care - Supervision	700-10	1,089	2,069	2,126	
18	Customer Contact - ABSU contract	700-20	47,127	48,470	49,422	
19	Bad Debt Management and Administration	700-30	6,112	5,874	6,018	
20	Customer Management & Sales	700-40	3,349	4,893	5,435	
21	**Customer Care Total**	**700**	**57,677**	**61,305**	**63,001**	
22						
23	Business & IT Services - Supervision	800-10	1,419	1,239	1,268	
24	Application Management	800-20	9,313	12,682	13,512	
25	Infrastructure Management	800-30	5,208	6,461	6,775	
26	Procurement Services	800-40	736	824	874	
27	**Business & IT Services Total**	**800**	**16,675**	**21,205**	**22,428**	
28						
29	Administration & General	900-11	3,229	2,293	2,315	
30	Insurance	900-12	4,725	4,410	4,631	
31	Finance and Regulatory Affairs	900-13	9,585	9,641	9,994	
32	Shared Services Agreement	900-14	3,541	1,242	868	
33	Corporate Administration Total	900-10	21,080	17,586	17,808	
34	Forecasting	900-20	1,022	1,632	1,672	
35	Public Affairs	900-30	1,375	1,731	1,762	
36	Business Development	900-40	1,416	3,679	3,925	
37	Human Resources	900-50	5,440	6,687	6,930	
38	Other Post Employment Benefits (OPEB)	900-60	5,991	3,389	4,111	
39	**Administration & General Total**	**900**	**36,324**	**34,704**	**36,207**	
40						
41	**Total Gross O&M Expenses**		**195,078**	**209,590**	**219,149**	
42						
43	Less: Vehicle Lease Reclass		(1,804)	-	-	
44	Less: Capitalized Overhead		(28,113)	(16,767)	(17,532)	
45						(X-Ref - Tab C-13, Schedule 4)
46	**Total O&M Expenses**		**$ 165,162**	**$ 192,823**	**$ 201,617**	(X-Ref - Tab C-13, Schedule 5)

TERASEN GAS INC. June 12, 2009 Advance Materials Section C
Tab 13
Schedule 31

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Total Expenses	2010 Revised Revenue, Total Expenses	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$14,351	$16,187	$16,187	$1,836	
4						
5	General, School and Other	33,242	33,006	33,006	(236)	
6						(X-Ref - Tab C-13, Schedule 4)
7	Total	$47,593	$49,193	$49,193	$1,600	(X-Ref - Tab C-13, Schedule 12)

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Total Expenses	2011 Revised Revenue, Total Expenses	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$16,187	$16,067	$16,067	($120)	
4						
5	General, School and Other	33,006	34,144	34,144	1,138	
6						(X-Ref - Tab C-13, Schedule 5)
7	Total	$49,193	$50,211	$50,211	$1,018	(X-Ref - Tab C-13, Schedule 13)

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation Provision**				
2					
3	Total Depreciation Expense	$86,357	$113,009	$26,652	- Tab C-13, Schedule 49
4					
5	Less: Amortization of Contributions in Aid of Construction	(6,560)	(6,849)	(289)	- Tab C-13, Schedule 52
6		79,797	106,160	$26,363	
7			(X-Ref - Tab C-13, Schedule 37)		
8	**Amortization Expense**				
9					
10	Amortization of Deferred Charges	($72)	($2,364)	($2,292)	- Tab C-13, Schedule 54
11					
12		(72)	(2,364)	(2,292)	
13					(X-Ref - Tab C-13, Schedule 4)
14	TOTAL	$79,725	103,796	$24,071	(X-Ref - Tab C-13, Schedule 12)

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation Provision**				
2					
3	Total Depreciation Expense	$113,009	$115,696	$2,687	- Tab C-13, Schedule 51
4					
5	Less: Amortization of Contributions in Aid of Construction	(6,849)	(6,674)	175	- Tab C-13, Schedule 53
6		106,160	109,022	2,862	
7			(X-Ref - Tab C-13, Schedule 38)		
8	**Amortization Expense**				
9					
10	Amortization of Deferred Charges	($2,364)	$1,474	$3,838	- Tab C-13, Schedule 55
11					
12		(2,364)	1,474	3,838	
13					(X-Ref - Tab C-13, Schedule 5)
14	TOTAL	$103,796	$110,496	$6,700	(X-Ref - Tab C-13, Schedule 13)

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Existing Rates	2010 ----Revised Rates----- Revised Revenue	2010 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$206,525	$165,328	$19,926	$185,254	($21,271)	- Tab C-13, Schedule 4
3	Deduct - Interest on Debt	(108,525)	(110,050)	(6)	(110,056)	(1,531)	- Tab C-13, Schedule 10
4	Add- Non-Tax Ded. Expense (Net)	428	(1,864)	-	(1,864)	(2,292)	- Tab C-13, Schedule 37
5							
6	Accounting Income After Tax	98,428	53,414	19,920	73,334	(25,094)	
7	Add (Deduct) - Timing Differences	(44,736)	5,999	-	5,999	50,735	- Tab C-13, Schedule 37
8							
9	Taxable Income After Tax	$53,692	$59,413	$19,920	$79,333	$25,641	
10							
11		30.000%	28.500%	28.500%	28.500%	-1.500%	
12	1 - Current Income Tax Rate	70.000%	71.500%	71.500%	71.500%	1.500%	
13							
14	Taxable Income	76,702	$83,095	$27,860	$110,955	$34,253	
15							(X-Ref - Tab C-13, Schedule 4)
16	**Total Income Tax**	$23,011	$23,682	$7,940	$31,622	$8,611	(X-Ref - Tab C-13, Schedule 12)

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Existing Rates	2011 ----Revised Rates----- Revised Revenue	2011 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$185,254	$156,492	$36,640	$193,132	$7,878	- Tab C-13, Schedule 5
3	Deduct - Interest on Debt	(110,056)	(115,417)	(13)	(115,430)	(5,374)	- Tab C-13, Schedule 11
4	Add- Non-Tax Ded. Expense (Net)	(1,864)	1,974	-	1,974	3,838	- Tab C-13, Schedule 38
5							
6	Accounting Income After Tax	73,334	43,049	36,627	79,676	6,342	
7	Add (Deduct) - Timing Differences	5,999	8,118	-	8,118	2,119	- Tab C-13, Schedule 38
8							
9	Taxable Income After Tax	$79,333	$51,167	$36,627	$87,794	$8,461	
10							
11		28.500%	26.500%	26.500%	26.500%	-2.000%	
12	1 - Current Income Tax Rate	71.500%	73.500%	73.500%	73.500%	2.000%	
13							
14	Taxable Income	$110,955	$69,615	$49,833	$119,448	$423,050	
15							(X-Ref - Tab C-13, Schedule 5)
16	**Total Income Tax**	$31,622	$18,448	$13,206	$31,654	$32	(X-Ref - Tab C-13, Schedule 13)

NON-TAX DEDUCTIBLE EXPENSES (NET) AND TIMING DIFFERENCE ADJUSTMENTS
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**ITEMS OF A PERMANENT NATURE INCREASING TAXABLE INCOME**				
2					
3	Amortization of Deferred Charges	($72)	($2,364)	($2,292)	- Tab C-13, Schedule 54
4					
5	Non-tax Deductible Expenses	500	500	-	
6					
7	Total Permanent Differences	$428	($1,864)	($2,292)	(X-Ref - Tab C-13, Schedule 35)
8					(X-Ref - Tab C-13, Schedule 6)
9	**TIMING DIFFERENCE ADJUSTMENTS**				
10					
11	Addbacks:				
12	Depreciation	$79,797	$106,160	$26,363	- Tab C-13, Schedule 33
13	Amortization of Debt Issue Expenses	626	721	95	
14	Vehicle Capital Lease: Interest & Capitialized Depreciation	-	1,597	1,597	
15	Pension Expense	2,310	4,779	2,469	
16	OPEB Expense	-	5,320	5,320	
17					
18	Deductions:				
19	Capital Cost Allowance	(87,538)	(98,544)	(11,006)	- Tab C-13, Schedule 39
20	Cumulative Eligible Capital Allowance	(1,070)	(1,001)	69	
21	Debt Issue Costs	(1,368)	(1,206)	162	
22	Vehicle Lease Payment	-	(3,149)	(3,149)	
23	Pension Contributions	(6,814)	(7,115)	(301)	
24	OPEB Contributions	-	(503)	(503)	
25	Overheads Capitalized Expensed for Tax Purposes	(14,056)	-	14,056	
26	Overhead Capitalization Rate Change	(3,335)	-	3,335	
27	CCA Rate Change of 2007 & 2008	(2,933)	-	2,933	
28	Long Term Compensation	(2,195)	-	2,195	
29	Discounts on Debt Issue and Other	-	-	-	
30	Major Inspection Costs	-	(1,060)	(1,060)	
31	SCP Landscaping Deduction	(8,160)	-	8,160	
32					
33	Total Timing Differences	($44,736)	$5,999	$50,735	(X-Ref - Tab C-13, Schedule 35)
					(X-Ref - Tab C-13, Schedule 6)

NON-TAX DEDUCTIBLE EXPENSES (NET) AND TIMING DIFFERENCE ADJUSTMENTS
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**ITEMS OF A PERMANENT NATURE INCREASING TAXABLE INCOME**				
2					
3	Amortization of Deferred Charges	($2,364)	$1,474	$3,838	- Tab C-13, Schedule 55
4					
5	Non-tax Deductible Expenses	500	500	-	
6					
7	Total Permanent Differences	($1,864)	$1,974	$3,838	(X-Ref - Tab C-13, Schedule 36)
8					(X-Ref - Tab C-13, Schedule 6)
9	**TIMING DIFFERENCE ADJUSTMENTS**				
10					
11	Addbacks:				
12	Depreciation	$106,160	$109,022	$2,862	- Tab C-13, Schedule 34
13	Amortization of Debt Issue Expenses	721	721	-	
14	Vehicle Capital Lease: Interest & Capitialized Depreciation	1,597	2,029	432	
15	Pension Expense	4,779	5,704	925	
16	OPEB Expense	5,320	5,297	(23)	
17					
18	Deductions:				
19	Capital Cost Allowance	(98,544)	(100,844)	(2,300)	- Tab C-13, Schedule 40
20	Cumulative Eligible Capital Allowance	(1,001)	(937)	64	
21	Debt Issue Costs	(1,206)	(1,003)	203	
22	Vehicle Lease Payment	(3,149)	(3,736)	(587)	
23	Pension Contributions	(7,115)	(7,322)	(207)	
24	OPEB Contributions	(503)	(503)	-	
25	Overheads Capitalized Expensed for Tax Purposes	-	-	-	
26	Overhead Capitalization Rate Change	-	-	-	
27	CCA Rate Change of 2007 & 2008	-	-	-	
28	Long Term Compensation	-	-	-	
29	Discounts on Debt Issue and Other	-	-	-	
30	Major Inspection Costs	(1,060)	(310)	750	
31	SCP Landscaping Deduction	-	-	-	
32					
33	Total Timing Differences	$5,999	$8,118	$2,119	(X-Ref - Tab C-13, Schedule 36)
					(X-Ref - Tab C-13, Schedule 7)

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Class	CCA Rate %	12/31/2009 UCC Balance	Adjustments	2010 Net Additions	2010 CCA	12/31/2010 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$1,183,088	$0	$371	($47,331)	$1,136,128
2	1.3	6%	8,111	-	2,757	(569)	10,299
3	2	6%	164,165	-	-	(9,850)	154,315
4	3	5%	2,826	-	-	(141)	2,685
5	6	10%	206	-	-	(21)	185
6	7	15%	3,807	-	1,913	(714)	5,006
7	8	20%	15,184	-	2,441	(3,281)	14,344
8	10	30%	3,135	-	1,629	(1,185)	3,579
9	12	100%	-	3,087	13,601	(9,887)	6,801
10	13	Manual	2,682	-	167	(890)	1,959
11	14	Manual	2	-	-	(2)	-
12	17	8%	223	-	-	(18)	205
13	38	30%	225	-	30	(72)	183
14	39	25%	-	-	-	-	-
15	45	45%	891	-	-	(401)	490
16	47	8%	4,791	-	451	(401)	4,841
17	49	8%	65,789	-	14,546	(5,845)	74,490
18	50 / 52	55% / 100%	1,432	-	4,489	(5,276)	645
19	51	6%	171,718	-	78,560	(12,660)	237,618
20							
21		Total	$1,628,275	$3,087	$120,955	($98,544)	$1,653,773
22						(X-Ref - Tab C-13, Schedule 37)	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Class	CCA Rate %	12/31/2010 UCC Balance	Adjustments	2011 Net Additions	2011 CCA	12/31/2011 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$1,136,128	$0	$0	($45,445)	$1,090,683
2	1.3	6%	10,299	-	3,521	(724)	13,096
3	2	6%	154,315	-	-	(9,259)	145,056
4	3	5%	2,685	-	-	(134)	2,551
5	6	10%	185	-	-	(19)	166
6	7	15%	5,006	-	1,586	(870)	5,722
7	8	20%	14,344	-	2,214	(3,090)	13,468
8	10	30%	3,579	-	1,607	(1,315)	3,871
9	12	100%	6,801	-	13,000	(13,300)	6,501
10	13	Manual	1,959	-	51	(883)	1,127
11	14	Manual	-	-	-	-	-
12	17	8%	205	-	-	(17)	188
13	38	30%	183	-	30	(59)	154
14	39	25%	-	-	-	-	-
15	45	45%	490	-	-	(220)	270
16	47	8%	4,841	-	1,620	(452)	6,009
17	49	8%	74,490	-	17,067	(6,642)	84,915
18	50 / 52	55% / 100%	645	-	5,000	(1,729)	3,916
19	51	6%	237,618	-	80,971	(16,686)	301,903
20							
21		Total	$1,653,773	$0	$126,667	($100,844)	$1,679,596
22						(X-Ref - Tab C-13, Schedule 38)	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Existing 2009 Rates	2010 Adjustments	2010 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,215,664	$3,317,590	$0	$3,317,590	$101,926	- Tab C-13, Schedule 45
2	Adjustment - CPCNs	12,879				(12,879)	- Tab C-13, Schedule 43
3	Gas Plant in Service, Ending	3,317,590	3,449,336	-	3,449,336	131,746	- Tab C-13, Schedule 45
4							
5	Accumulated Depreciation Beginning - Plant	($743,486)	($779,187)	$0	($779,187)	($35,701)	- Tab C-13, Schedule 49
6	Accumulated Depreciation Ending - Plant	(779,187)	(840,835)	-	(840,835)	(61,648)	- Tab C-13, Schedule 49
7							
8	CIAC, Beginning	($161,636)	($176,845)	$0	($176,845)	($15,209)	- Tab C-13, Schedule 52
9	CIAC, Ending	(176,845)	(183,817)	-	(183,817)	(6,972)	- Tab C-13, Schedule 52
10							
11	Accumulated Amortization Beginning - CIAC	$45,381	$44,146	$0	$44,146	($1,235)	- Tab C-13, Schedule 52
12	Accumulated Amortization Ending - CIAC	44,146	47,061	-	47,061	2,915	- Tab C-13, Schedule 52
13							
14	Net Plant in Service, Mid-Year	$2,387,253	$2,438,725	$0	$2,438,725	$51,472	
15							
16	Adjustment to 13-Month Average	(10,554)	13,537	-	13,537	24,091	
17	Work in Progress, No AFUDC	15,627	15,627	-	15,627	-	
18	Unamortized Deferred Charges	(66,709)	(27,015)	-	(27,015)	39,694	- Tab C-13, Schedule 54
19	Cash Working Capital	(27,183)	(7,178)	400	(6,778)	20,405	- Tab C-13, Schedule 56
20	Other Working Capital (incl. Construction Advances)	115,701	103,439	-	103,439	(12,262)	- Tab C-13, Schedule 56
21	Future Income Taxes Regulatory Asset	278,048	284,455	-	284,455	6,407	- Tab C-13, Schedule 61
22	Future Income Taxes Regulatory Liability	(278,048)	(284,455)	-	(284,455)	(6,407)	- Tab C-13, Schedule 61
23	LILO Benefit	(1,814)	(1,648)	-	(1,648)	166	
24	**Utility Rate Base**	$2,412,321	$2,535,487	$400	$2,535,887	$123,566	(X-Ref - Tab C-13, Schedule 10)

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Existing 2009 Rates	2011 Adjustments	2011 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,317,590	$3,449,336	$0	$3,449,336	$131,746	- Tab C-13, Schedule 47
2	Adjustment - CPCNs	-				-	
3	Gas Plant in Service, Ending	3,449,336	3,535,828	-	3,535,828	86,492	- Tab C-13, Schedule 47
4							
5	Accumulated Depreciation Beginning - Plant	($779,187)	($840,835)	$0	($840,835)	($61,648)	- Tab C-13, Schedule 51
6	Accumulated Depreciation Ending - Plant	(840,835)	(899,386)	-	(899,386)	(58,551)	- Tab C-13, Schedule 51
7							
8	CIAC, Beginning	($176,845)	($183,817)	$0	($183,817)	($6,972)	- Tab C-13, Schedule 53
9	CIAC, Ending	(183,817)	(194,646)	-	(194,646)	(10,829)	- Tab C-13, Schedule 53
10							
11	Accumulated Amortization Beginning - CIAC	$44,146	$47,061	$0	$47,061	$2,915	- Tab C-13, Schedule 53
12	Accumulated Amortization Ending - CIAC	47,061	50,241	-	50,241	3,180	- Tab C-13, Schedule 53
13							
14	Net Plant in Service, Mid-Year	$2,438,725	$2,481,891	$0	$2,481,891	$43,167	
15							
16	Adjustment to 13-Month Average	13,537	-	-	-	(13,537)	
17	Work in Progress, No AFUDC	15,627	15,627	-	15,627	-	
18	Unamortized Deferred Charges	(27,015)	10,347	-	10,347	37,362	- Tab C-13, Schedule 55
19	Cash Working Capital	(6,778)	(6,560)	427	(6,133)	645	- Tab C-13, Schedule 57
20	Other Working Capital (incl. Construction Advances)	103,439	120,091	-	120,091	16,652	- Tab C-13, Schedule 57
21	Future Income Taxes Regulatory Asset	284,455	292,155	-	292,155	7,700	- Tab C-13, Schedule 61
22	Future Income Taxes Regulatory Liability	(284,455)	(292,155)	-	(292,155)	(7,700)	- Tab C-13, Schedule 61
23	LILO Benefit	(1,648)	(1,482)	-	(1,482)	166	
24	**Utility Rate Base**	$2,535,887	$2,619,914	$427	$2,620,341	$84,454	(X-Ref - Tab C-13, Schedule 11)

TERASEN GAS INC. June 12, 2009 Advance Materials Section C
Tab 13
Schedule 43

CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2009 - 2011
($000)

Line No.	Particulars	Projected 2009	Forecast 2010	Forecast 2011	Reference
	(1)	(3)	(4)	(5)	(6)
1	**CAPITAL EXPENDITURES**				
2					
3	Regular Capital Expenditures				
4	Regular Capital Expenditures	88,789	97,215	111,201	
5	Gateway Project *	11,174	6,750	10,433	
6					
7	Total Regular Capital Expenditures	$ 99,963	$ 103,965	$ 121,634	
8					
9	Special Projects - CPCN's				
10	Vancouver LP Replacement	250	-	-	
11	Fraser River SBSA Rehabilitation	25,000	520	-	
12	Okanagan Reinforcement Project	500	500	500	
13	CCE CPCN	7,476	49,662	57,761	
18	Total CPCN's	$ 33,226	$ 50,682	$ 58,261	
19					
20					
21	TOTAL CAPITAL EXPENDITURES	$ 133,189	$ 154,647	$ 179,895	
22					
23					
24	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**				
25					
26	Regular Capital				
27	Regular Capital Expenditures	99,963	103,965	121,634	
28	Add - Opening WIP	18,760	26,589	25,960	
29	Less - Opening WIP Adjustment	-	-	-	
30	Less - Closing WIP	(26,589)	(25,960)	(33,703)	
31	Capital Spares Inventory Reclassification	8,593	-	-	
32	Capital Vehicle Lease Addition	-	3,869	2,735	
33	Add - AFUDC	269	257	350	- Tab C-13, Schedule 45
34	Add - Overhead Capitalized	28,113	16,767	17,532	- Tab C-13, Schedule 47
35					
36	TOTAL REGULAR CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	$ 129,108	$ 125,488	$ 134,507	
37					
38	Special Projects - CPCN's				
39	CPCN Expenditures	33,226	50,682	58,261	
40	Add - Opening WIP	14,676	35,291	60,405	
41	Less - Closing WIP	(35,291)	(60,405)	(124,194)	
42	Less: Vancouver LP Removal costs (added to Accumulated Depreciation)	(394)	-	-	
43	Add - AFUDC	662	2,035	5,528	
44					- Tab C-13, Schedule 45
45	TOTAL CPCN ADDITIONS TO OPENING GAS PLANT IN SERVICE	$ 12,879	$ 27,603	-$ 0	- Tab C-13, Schedule 47
46		(X-Ref - Tab C-13, Schedule 41)			
47	TOTAL PLANT ADDITIONS	$ 141,987	$ 153,090	$ 134,507	
48					
49	Capital Vehicle Lease Opening Adjustment	-	26,103	-	- Tab C-13, Schedule 45
50					
51	TOTAL PLANT ADDITIONS and OPENING ADJUSTMENTS	$ 141,987	$ 179,193	$ 134,507	
52					
53					
54	* Spending associated with the Gateway Project is expected to be fully recovered via a contribution in aid of construction.				

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Balance 12/31/2009	CPCN'S	2010 Additions	2010 AFUDC	Retirements	Transfers/ Recovery	Balance 12/31/2010	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	117-00 Utility Plant Acquisition Adjustment	$0	$0	$0	$0	$0	$0	$0	$0
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	-	-	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	63	-	-	-	-	-	63	63
9	402-00 Other Intangible Plant	688	-	-	-	-	-	688	688
10	461-00 Land Rights - Transmission	43,782	-	121	-	-	-	43,903	43,843
11	461-10 Land Rights - Transmission - Byron Creek	16	-	-	-	-	-	16	16
12	471-00 Land Rights - Distribution	1,065	-	-	-	-	-	1,065	1,065
13	471-10 Land Rights - Distribution - Byron Creek	-	-	-	-	-	-	-	-
14	402-01 Application Software - 12.5%	55,628	-	13,601	78	(8,954)	-	60,353	57,991
15	402-02 Application Software - 20%	8,051	-	-	-	(1,847)	-	6,204	7,128
16	TOTAL INTANGIBLE PLANT	111,006	-	13,722	78	(10,801)	-	114,005	112,506
17									
18	**MANUFACTURED GAS / LOCAL STORAGE**								
19	430 Manufact'd Gas - Land	31	-	-	-	-	-	31	31
20	432 Manufact'd Gas - Struct. & Improvements	475	-	-	-	-	-	475	475
21	433 Manufact'd Gas - Equipment	422	-	372	-	-	-	794	608
22	434 Manufact'd Gas - Gas Holders	660	-	-	-	-	-	660	660
23	436 Manufact'd Gas - Compressor Equipment	53	-	-	-	-	-	53	53
24	437 Manufact'd Gas - Measuring & Regulating Equipment	309	-	-	-	-	-	309	309
25	440/441 Land in Fee Simple	928	-	-	-	-	-	928	928
26	442 Structures & Improvements	4,885	-	-	-	-	-	4,885	4,885
27	443 Gas Holders - Storage	16,654	-	453	4	-	-	17,111	16,883
28	446 Compressor Equipment	-	-	-	-	-	-	-	-
29	447 Measuring & Regulating Equipment	-	-	-	-	-	-	-	-
30	448 Purification Equipment	-	-	-	-	-	-	-	-
31	449 Local Storage Equipment	23,393	-	-	-	-	-	23,393	23,393
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	47,810	-	825	4	-	-	48,639	48,225
33									
34	**TRANSMISSION PLANT**								
35	460-00 Land in Fee Simple	7,408	-	-	-	-	-	7,408	7,408
36	462-00 Compressor Structures	14,690	-	-	-	-	-	14,690	14,690
37	463-00 Measuring Structures	4,948	-	-	-	-	-	4,948	4,948
38	464-00 Other Structures & Improvements	5,959	-	-	-	-	-	5,959	5,959
39	465-00 Mains	736,179	27,349	19,865	93	(998)	(1,985)	780,503	772,016 *
40	465-00 Mains - Inspection	-	-	1,315	6	-	1,985	3,306	1,653
41	465-10 Mains - Byron Creek	932	-	-	-	-	-	932	932
42	466-00 Compressor Equipment	110,988	-	1,546	7	-	-	112,541	111,765
43	466-00 Compressor Equipment - Overhaul	-	-	-	-	-	-	-	-
44	467-00 Measuring & Regulating Equipment	29,406	-	-	-	-	-	29,406	29,406
45	467-10 Telemetering	8,469	-	93	-	-	-	8,562	8,516
46	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	39	39
47	468-00 Communication Structures & Equipment	346	-	-	-	-	-	346	346
48	469-00 Other Transmission Equipment	-	-	-	-	-	-	-	-
49	TOTAL TRANSMISSION PLANT	919,364	27,349	22,819	106	(998)	-	968,640	957,677
50									
51	* Adjusted for full year impact of 2009 Fraser River SBSA CPCN.								

TERASEN GAS INC. June 12, 2009 Advance Materials Section C
Tab 13
Schedule 45

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Balance 12/31/2009	CPCN'S	2010 Additions	2010 AFUDC	Retirements	Transfers/ Recovery	Balance 12/31/2010	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	470-00 Land in Fee Simple	$3,418	$0	$0	$0	$0	$0	$3,418	$3,418
3	472-00 Structures & Improvements	14,696	-	-	-	-	-	14,696	14,696
4	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	107	107
5	473-00 Services	641,679	254	26,316	-	(6,579)	-	661,670	651,802 **
6	473-00 Services - LILO	43,229	-	-	-	-	-	43,229	43,229
7	474-00 House Regulators & Meter Installations	134,370	-	12,014	3	(9,614)	-	136,773	135,572
8	474-00 House Regulators & Meter Installations - LILO	16,070	-	-	-	-	-	16,070	16,070
9	475-00 Mains	845,058	-	19,758	32	(1,979)	-	862,869	853,964
10	475-00 Mains - LILO	39,704	-	-	-	-	-	39,704	39,704
11	476-00 Compressor Equipment	571	-	-	-	-	-	571	571
12	477-00 Measuring & Regulating Equipment	82,474	-	4,739	21	(714)	-	86,520	84,497
13	477-00 Telemetering	5,914	-	223	1	(11)	-	6,127	6,021
14	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	163	163
15	478-10 Meters	184,820	-	9,836	-	(7,869)	-	186,787	185,804
16	478-11 Meters - LILO	10,027	-	-	-	-	-	10,027	10,027
17	478-20 Instruments	11,251	-	-	-	-	-	11,251	11,251
18	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-
19	TOTAL DISTRIBUTION PLANT	2,033,551	254	72,886	57	(26,766)	-	2,079,982	2,056,894
20									
21	**GENERAL PLANT & EQUIPMENT**								
22	480-00 Land in Fee Simple	21,905	-	126	-	-	-	22,031	21,968
23	481-00 Land Rights	-	-	-	-	-	-	-	-
24	482-00 Structures & Improvements	-	-	-	-	-	-	-	-
25	- Frame Buildings	5,286	-	-	-	-	-	5,286	5,286
26	- Masonry Buildings	83,527	-	2,228	-	-	-	85,755	84,641
27	- Leasehold Improvement	473	-	167	1	-	-	641	557
28	Office Equipment & Furniture	-	-	-	-	-	-	-	-
29	483-30 GP Office Equipment	4,480	-	87	-	(90)	-	4,477	4,479
30	483-40 GP Furniture	19,730	-	509	1	(5)	-	20,235	19,983
31	483-10 GP Computer Hardware	18,220	-	4,489	10	(6,245)	-	16,474	17,347
32	483-20 GP Computer Software	853	-	-	-	(20)	-	833	843
33	483-21 GP Computer Software	-	-	-	-	-	-	-	-
34	484-00 Transportation Equipment	2,279	-	1,629	-	-	-	3,908	3,094
35	484-00 Vehicles - Leased	-	-	3,869	-	(2,321)	26,103	27,651	26,877
36	485-10 Heavy Work Equipment	209	-	-	-	-	-	209	209
37	485-20 Heavy Mobile Equipment	561	-	30	-	-	-	591	576
38	486-00 Small Tools & Equipment	32,177	-	1,137	-	-	-	33,314	32,746
39	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	24	24
40	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-
41	488-00 Communications Equipment	-	-	-	-	-	-	-	-
42	- Telephone	11,239	-	504	-	(202)	-	11,541	11,390
43	- Radio	4,896	-	204	-	-	-	5,100	4,998
44	489-00 Other General Equipment	-	-	-	-	-	-	-	-
45	TOTAL GENERAL PLANT	205,859	-	14,979	12	(8,883)	26,103	238,070	235,016
46									
47	**UNCLASSIFIED PLANT**								
48	499 Plant Suspense	-	-	-	-	-	-	-	-
49	TOTAL UNCLASSIFIED PLANT	-	-	-	-	-	-	-	-
53									
54	TOTAL CAPITAL	$3,317,590	$27,603	$125,231	$257	($47,448)	$26,103	$3,449,336	$3,410,317

55 (X-Ref - Tab C-13, Schedule 8) (X-Ref - Tab C-13, Schedule 43) (X-Ref - Tab C-13, Schedule 49)
56 ** Adjusted for full year impact of 2009 Vancouver LP Replacement CPCN. (X-Ref - Tab C-13, Schedule 8)

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciatior
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	117-00 Utility Plant Acquisition Adjustment	$0	$0	$0	$0	$0	$0	$0	$0
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	-	-	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	63	-	-	-	-	-	63	63
9	402-00 Other Intangible Plant	688	-	-	-	-	-	688	688
10	461-00 Land Rights - Transmission	43,903	-	124	-	-	-	44,027	43,965
11	461-10 Land Rights - Transmission - Byron Creek	16	-	-	-	-	-	16	16
12	471-00 Land Rights - Distribution	1,065	-	-	-	-	-	1,065	1,065
13	471-10 Land Rights - Distribution - Byron Creek	-	-	-	-	-	-	-	-
14	402-01 Application Software - 12.5%	60,353	-	13,000	78	(10,840)	-	62,591	61,472
15	402-02 Application Software - 20%	6,204	-	-	-	(1,147)	-	5,057	5,631
16	TOTAL INTANGIBLE PLANT	114,005	-	13,124	78	(11,987)	-	115,220	114,613
17									
18	**MANUFACTURED GAS / LOCAL STORAGE**								
19	430 Manufact'd Gas - Land	31	-	-	-	-	-	31	31
20	432 Manufact'd Gas - Struct. & Improvements	475	-	-	-	-	-	475	475
21	433 Manufact'd Gas - Equipment	794	-	-	-	-	-	794	794
22	434 Manufact'd Gas - Gas Holders	660	-	-	-	-	-	660	660
23	436 Manufact'd Gas - Compressor Equipment	53	-	-	-	-	-	53	53
24	437 Manufact'd Gas - Measuring & Regulating Equipment	309	-	-	-	-	-	309	309
25	440/441 Land in Fee Simple	928	-	-	-	-	-	928	928
26	442 Structures & Improvements	4,885	-	-	-	-	-	4,885	4,885
27	443 Gas Holders - Storage	17,111	-	1,617	17	-	-	18,745	17,928
28	446 Compressor Equipment	-	-	-	-	-	-	-	-
29	447 Measuring & Regulating Equipment	-	-	-	-	-	-	-	-
30	448 Purification Equipment	-	-	-	-	-	-	-	-
31	449 Local Storage Equipment	23,393	-	-	-	-	-	23,393	23,393
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	48,639	-	1,617	17	-	-	50,273	49,456
33									
34	**TRANSMISSION PLANT**								
35	460-00 Land in Fee Simple	7,408	-	-	-	-	-	7,408	7,408
36	462-00 Compressor Structures	14,690	-	-	-	-	-	14,690	14,690
37	463-00 Measuring Structures	4,948	-	-	-	-	-	4,948	4,948
38	464-00 Other Structures & Improvements	5,959	-	-	-	-	-	5,959	5,959
39	465-00 Mains	780,503	-	27,167	174	(1,367)	-	806,477	793,490
40	465-00 Mains - Inspection	3,306	-	379	2	-	-	3,687	3,497
41	465-10 Mains - Byron Creek	932	-	-	-	-	-	932	932
42	466-00 Compressor Equipment	112,541	-	1,581	8	-	-	114,130	113,336
43	466-00 Compressor Equipment - Overhaul	-	-	-	-	-	-	-	-
44	467-00 Measuring & Regulating Equipment	29,406	-	-	-	-	-	29,406	29,406
45	467-10 Telemetering	8,562	-	61	-	-	-	8,623	8,593
46	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	39	39
47	468-00 Communication Structures & Equipment	346	-	-	-	-	-	346	346
48	469-00 Other Transmission Equipment	-	-	-	-	-	-	-	-
49	TOTAL TRANSMISSION PLANT	968,640	-	29,188	184	(1,367)	-	996,645	982,643

TERASEN GAS INC. June 12, 2009 Advance Materials Section C
Tab 13
Schedule 47

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciatior
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	470-00 Land in Fee Simple	$3,418	$0	$0	$0	$0	$0	$3,418	$3,418
3	472-00 Structures & Improvements	14,696	-	-	-	-	-	14,696	14,696
4	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	107	107
5	473-00 Services	661,670	-	27,863	-	(6,966)	-	682,567	672,119
6	473-00 Services - LILO	43,229	-	-	-	-	-	43,229	43,229
7	474-00 House Regulators & Meter Installations	136,773	-	12,619	3	(10,098)	-	139,297	138,035
8	474-00 House Regulators & Meter Installations - LILO	16,070	-	-	-	-	-	16,070	16,070
9	475-00 Mains	862,869	-	19,794	32	(1,983)	-	880,712	871,791
10	475-00 Mains - LILO	39,704	-	-	-	-	-	39,704	39,704
11	476-00 Compressor Equipment	571	-	-	-	-	-	571	571
12	477-00 Measuring & Regulating Equipment	86,520	-	4,751	24	(716)	-	90,579	88,550
13	477-00 Telemetering	6,127	-	220	1	(11)	-	6,337	6,232
14	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	163	163
15	478-10 Meters	186,787	-	10,347	-	(8,277)	-	188,857	187,822
16	478-11 Meters - LILO	10,027	-	-	-	-	-	10,027	10,027
17	478-20 Instruments	11,251	-	-	-	-	-	11,251	11,251
18	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-
19	TOTAL DISTRIBUTION PLANT	2,079,982	-	75,594	60	(28,051)	-	2,127,585	2,103,784
20									
21	**GENERAL PLANT & EQUIPMENT**								
22	480-00 Land in Fee Simple	22,031	-	129	-	-	-	22,160	22,096
23	481-00 Land Rights	-	-	-	-	-	-	-	-
24	482-00 Structures & Improvements	-	-	-	-	-	-	-	-
25	- Frame Buildings	5,286	-	-	-	-	-	5,286	5,286
26	- Masonry Buildings	85,755	-	2,869	-	-	-	88,624	87,190
27	- Leasehold Improvement	641	-	51	-	-	-	692	667
28	Office Equipment & Furniture	-	-	-	-	-	-	-	-
29	483-30 GP Office Equipment	4,477	-	60	-	(991)	-	3,546	4,012
30	483-40 GP Furniture	20,235	-	418	1	(1,230)	-	19,424	19,830
31	483-10 GP Computer Hardware	16,474	-	5,000	10	-	-	21,484	18,979
32	483-20 GP Computer Software	833	-	-	-	(198)	-	635	734
33	483-21 GP Computer Software	-	-	-	-	-	-	-	-
34	484-00 Transportation Equipment	3,908	-	1,607	-	-	-	5,515	4,712
35	484-00 Vehicles - Leased	27,651	-	2,735	-	(1,641)	-	28,745	28,198
36	485-10 Heavy Work Equipment	209	-	-	-	-	-	209	209
37	485-20 Heavy Mobile Equipment	591	-	30	-	-	-	621	606
38	486-00 Small Tools & Equipment	33,314	-	1,105	-	-	-	34,419	33,867
39	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	24	24
40	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-
41	488-00 Communications Equipment	-	-	-	-	-	-	-	-
42	- Telephone	11,541	-	464	-	(1,596)	-	10,409	10,975
43	- Radio	5,100	-	166	-	(954)	-	4,312	4,706
44	489-00 Other General Equipment	-	-	-	-	-	-	-	-
45	TOTAL GENERAL PLANT	238,070	-	14,634	11	(6,610)	-	246,105	242,088
46									
47	**UNCLASSIFIED PLANT**								
48	499 Plant Suspense	-	-	-	-	-	-	-	-
49	TOTAL UNCLASSIFIED PLANT	-	-	-	-	-	-	-	-
53									
54	TOTAL CAPITAL	$3,449,336	$0	$134,157	$350	($48,015)	$0	$3,535,828	$3,492,582
55		(X-Ref - Tab C-13, Schedule 9)	(X-Ref - Tab C-13, Schedule 43)					(X-Ref - Tab C-13, Schedule 51)	
								(X-Ref - Tab C-13, Schedule 9)	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Account	Mid-year GPIS for Depreciation		Annual Depreciation Rate %	Provision 2010 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Accumulated 12/31/2009	Accumulated 12/31/2010
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$0		1.00%	$0	$0	$0	$0	$0	$0
3	175-00 Unamortized Conversion Expense	109		1.00%	1	-	-	-	365	366
4	175-00 Unamortized Conversion Expense - Squamish	777		10.00%	78	-	-	-	156	234
5	178-00 Organization Expense	728		1.00%	7	-	-	-	369	376
6	179-01 Other Deferred Charges	-		0.00%	-	-	-	-	-	-
7	401-00 Franchise and Consents	99		19.76%	20	-	-	-	49	69
8	402-00 Utility Plant Acquisition Adjustment	63		23.66%	15	-	-	-	27	42
9	402-00 Other Intangible Plant	688		2.14%	15	-	-	-	151	166
10	461-00 Land Rights - Transmission	43,843		0.00%	-	-	-	-	651	651
11	461-10 Land Rights - Transmission - Byron Creek	16		0.00%	-	-	-	-	19	$19
12	471-00 Land Rights - Distribution	1,065		0.00%	-	-	-	-	2	2
13	471-10 Land Rights - Distribution - Byron Creek	-		0.00%	-	-	-	-	1	1
14	402-01 Application Software - 12.5%	57,991		12.50%	7,249	(4,264)	(8,954)	-	31,197	25,228
15	402-02 Application Software - 20%	7,128		20.00%	1,426	-	(1,847)	-	4,160	3,739
16	TOTAL INTANGIBLE PLANT	112,506			8,811	(4,264)	(10,801)	-	37,147	30,893
17										
18	**MANUFACTURED GAS / LOCAL STORAGE**									
19	430 Manufact'd Gas - Land	31		0.00%	-	-	-	-	-	-
20	432 Manufact'd Gas - Struct. & Improvements	475		3.28%	16	-	-	-	89	105
21	433 Manufact'd Gas - Equipment	608		6.30%	38	-	-	-	51	89
22	434 Manufact'd Gas - Gas Holders	660		3.90%	26	-	-	-	173	199
23	436 Manufact'd Gas - Compressor Equipment	53		4.96%	3	-	-	-	24	27
24	437 Manufact'd Gas - Measuring & Regulating Equipm	309		19.50%	60	-	-	-	152	212
25	440/441 Land in Fee Simple and Land Rights	928		0.00%	-	-	-	-	1	1
26	442 Structures & Improvements	4,885		4.02%	196	-	-	-	2,252	2,448
27	443 Gas Holders - Storage	16,883		2.61%	441	-	-	-	9,684	10,125
28	446 Compressor Equipment	-		0.00%	-	-	-	-	-	-
29	447 Measuring & Regulating Equipment	-		0.00%	-	-	-	-	-	-
30	448 Purification Equipment	-		0.00%	-	-	-	-	-	-
31	449 Local Storage Equipment	23,393		3.70%	866	-	-	-	8,336	9,202
32	TOTAL MANUFACTURED GAS / LOCAL STORA(	48,225			1,646	-	-	-	20,762	22,408
33										
34	**TRANSMISSION PLANT**									
35	460-00 Land in Fee Simple	7,408		0.00%	-	-	-	-	401	401
36	462-00 Compressor Structures	14,690		4.03%	592	-	-	-	5,264	5,856
37	463-00 Measuring Structures	4,948		4.48%	222	-	-	-	1,314	1,536
38	464-00 Other Structures & Improvements	5,959		3.02%	180	-	-	-	1,365	1,545
39	465-00 Mains	772,016	*	1.79%	13,819	-	(998)	-	182,866	195,687
40	465-00 Mains - INSPECTION	1,653		Term	691	-	-	-	-	691
41	465-10 Mains - Byron Creek	932		5.00%	47	-	-	-	794	841
42	466-00 Compressor Equipment	111,765		3.50%	3,912	-	-	-	35,074	38,986
43	466-00 Compressor Equipment - OVERHAUL	-		Term	-	-	-	-	-	-
44	467-00 Measuring & Regulating Equipment	29,406		7.55%	2,220	-	-	-	6,266	8,486
45	467-10 Telemetering	8,516		1.33%	113	-	-	-	6,083	6,196
46	467-20 Measuring & Regulating Equipment - Byron Cr	39		4.21%	2	-	-	-	7	9
47	468-00 Communication Structures & Equipment	346		5.32%	18	-	-	-	277	295
48	469-00 Other Transmission Equipment	-		0.00%	-	-	-	-	-	-
49	TOTAL TRANSMISSION PLANT	957,677			21,816	-	(998)	-	239,711	260,529
50										
51	* Adjusted for full year impact of 2009 Fraser River SBSA CPCN.									

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision: 2010 (Cr.)	Provision: Adjust- ments	Provision: Retirements	Provision: Retirement Costs	Accumulated: 12/31/2009	Accumulated: 12/31/2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	470-00 Land in Fee Simple	$3,418	0.00%	$0	$0	$0	$0	$30	$30
3	472-00 Structures & Improvements	14,696	3.78%	556	-	-	-	3,231	3,787
4	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	-	16	21
5	473-00 Services	651,802 **	3.38%	22,031	-	(6,579)	(9,685)	77,708	83,475
6	473-00 Services - LILO	43,229	3.30%	1,427	-	-	-	16,079	17,506
7	474-00 House Regulators & Meter Installations	135,572	5.21%	7,063	-	(9,614)	(500)	(2,598)	(5,649)
8	474-00 House Regulators & Meter Installations - LILO	16,070	2.19%	352	-	-	-	8,272	8,624
9	475-00 Mains	853,964	2.26%	19,300	-	(1,979)	(500)	235,697	252,518
10	475-00 Mains - LILO	39,704	2.40%	953	-	-	-	15,605	16,558
11	476-00 Compressor Equipment	571	25.04%	143	-	-	-	403	546
12	477-00 Measuring & Regulating Equipment	84,497	5.72%	4,833	-	(714)	(105)	12,769	16,783
13	477-00 Telemetering	6,021	0.25%	15	-	(11)	-	6,386	6,390
14	477-10 Measuring & Regulating Equipment - Byron Cree	163	0.00%	-	-	-	-	200	200
15	478-10 Meters	185,804	5.31%	9,866	-	(7,869)	(500)	38,294	39,791
16	478-11 Meters - LILO	10,027	3.29%	330	-	-	-	4,067	4,397
17	478-20 Instruments	11,251	4.03%	453	-	-	-	2,815	3,268
18	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-	-
19		2,056,894		67,327	-	(26,766)	(11,290)	418,974	448,245
20									
21	**GENERAL PLANT & EQUIPMENT**								
22	480-00 Land in Fee Simple	21,968	0.00%	-	-	-	-	13	13
23	481-00 Land Rights	-	0.00%	-	-	-	-	-	-
24	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-	-
25	- Frame Buildings	5,286	3.67%	194	4,633	-	-	(3,059)	1,768
26	- Masonry Buildings	84,641	4.37%	3,699	1,048	-	-	7,996	12,743
27	- Leasehold Improvement	557	10.00%	56	218	-	-	88	362
28	Office Equipment & Furniture	-	0.00%	-	-	-	-	-	-
29	483-30 GP Office Equipment	4,479	6.67%	299	726	(90)	-	1,937	2,872
30	483-40 GP Furniture	19,983	5.00%	999	(824)	(5)	-	12,176	12,346
31	483-10 GP Computer Hardware	17,347	20.00%	3,469	(7,882)	(6,245)	-	17,871	7,213
32	483-20 GP Computer Software	843	20.00%	169	-	(20)	-	445	594
33	483-21 GP Computer Software	-	0.00%	-	-	-	-	-	-
34	484-00 Transportation Equipment	3,094	6.16%	191	(2,099)	-	-	2,832	924
35	484-00 Vehicles - Leased	26,877	Lease Term	2,464	14,066	(2,321)	-	-	14,209
36	485-10 Heavy Work Equipment	209	5.65%	12	39	-	-	73	124
37	485-20 Heavy Mobile Equipment	576	6.43%	37	424	-	-	(332)	129
38	486-00 Small Tools & Equipment	32,746	5.00%	1,637	570	-	-	14,380	16,587
39	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	-	6	8
40	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-	-
41	488-00 Communications Equipment	-	0.00%	-	-	-	-	-	-
42	- Telephone	11,390	6.67%	760	506	(202)	-	5,647	6,711
43	- Radio	4,998	6.67%	333	(696)	-	-	2,527	2,164
44	489-00 Other General Equipment	-	0.00%	-	-	-	-	-	-
45	TOTAL GENERAL PLANT	235,016		14,321	10,729	(8,883)	-	62,600	78,767
46									
47	**UNCLASSIFIED PLANT**								
48	499 Plant Suspense	-	0.00%	-	-	-	-	(7)	(7)
49	TOTAL UNCLASSIFIED PLANT	-		-	-	-	-	(7)	(7)
50									
51	TOTALS	$3,410,317		$113,921	$6,465	($47,448)	($11,290)	$779,187	$840,835
52		(X-Ref - Tab C-13, Schedule 45)						(X-Ref - Tab C-13, Schedule 8)	
53	Less: Capital Lease Vehicle Depreciation allocated to Capital Projects			(912)					
54									
55	**Net Depreciation Expense**			$113,009					
56				(X-Ref - Tab C-13, Schedule 33)					
57	** Adjusted for full year impact of 2009 Vancouver LP Replacement CPCN.								

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	117-00 Utility Plant Acquisition Adjustment	$0	1.00%	$0	$0	$0	$0	$0	$0
3	175-00 Unamortized Conversion Expense	109	1.00%	1	-	-	-	366	367
4	175-00 Unamortized Conversion Expense - Squamish	777	10.00%	78	-	-	-	234	312
5	178-00 Organization Expense	728	1.00%	7	-	-	-	376	383
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	19.76%	20	-	-	-	69	89
8	402-00 Utility Plant Acquisition Adjustment	63	23.66%	15	-	-	-	42	57
9	402-00 Other Intangible Plant	688	2.14%	15	-	-	-	166	181
10	461-00 Land Rights - Transmission	43,965	0.00%	-	-	-	-	651	651
11	461-10 Land Rights - Transmission - Byron Creek	16	0.00%	-	-	-	$0	$19	19
12	471-00 Land Rights - Distribution	1,065	0.00%	-	-	-	-	2	2
13	471-10 Land Rights - Distribution - Byron Creek	-	0.00%	-	-	-	-	1	1
14	402-01 Application Software - 12.5%	61,472	12.50%	7,684	-	(10,840)	-	25,228	22,072
15	402-02 Application Software - 20%	5,631	20.00%	1,126	-	(1,147)	-	3,739	3,718
16	TOTAL INTANGIBLE PLANT	114,613		8,946	-	(11,987)	-	30,893	27,852
17									
18	**MANUFACTURED GAS / LOCAL STORAGE**								
19	430 Manufact'd Gas - Land	31	0.00%	-	-	-	-	-	-
20	432 Manufact'd Gas - Struct. & Improvements	475	3.28%	16	-	-	-	105	121
21	433 Manufact'd Gas - Equipment	794	6.30%	50	-	-	-	89	139
22	434 Manufact'd Gas - Gas Holders	660	3.90%	26	-	-	-	199	225
23	436 Manufact'd Gas - Compressor Equipment	53	4.96%	3	-	-	-	27	30
24	437 Manufact'd Gas - Measuring & Regulating Equipm	309	19.50%	60	-	-	-	212	272
25	440/441 Land in Fee Simple and Land Rights	928	0.00%	-	-	-	-	1	1
26	442 Structures & Improvements	4,885	4.02%	196	-	-	-	2,448	2,644
27	443 Gas Holders - Storage	17,928	2.61%	468	-	-	-	10,125	10,593
28	446 Compressor Equipment	-	0.00%	-	-	-	-	-	-
29	447 Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-
30	448 Purification Equipment	-	0.00%	-	-	-	-	-	-
31	449 Local Storage Equipment	23,393	3.70%	866	-	-	-	9,202	10,068
32	TOTAL MANUFACTURED GAS / LOCAL STORA(	49,456		1,685	-	-	-	22,408	24,093
33									
34	**TRANSMISSION PLANT**								
35	460-00 Land in Fee Simple	7,408	0.00%	-	-	-	-	401	401
36	462-00 Compressor Structures	14,690	4.03%	592	-	-	-	5,856	6,448
37	463-00 Measuring Structures	4,948	4.48%	222	-	-	-	1,536	1,758
38	464-00 Other Structures & Improvements	5,959	3.02%	180	-	-	-	1,545	1,725
39	465-00 Mains	793,490	1.79%	14,203	-	(1,367)	-	195,687	208,523
40	465-00 Mains - INSPECTION	3,497	Term	553	-	-	-	691	1,244
41	465-10 Mains - Byron Creek	932	5.00%	47	-	-	-	841	888
42	466-00 Compressor Equipment	113,336	3.50%	3,967	-	-	-	38,986	42,953
43	466-00 Compressor Equipment - OVERHAUL	-	Term	-	-	-	-	-	-
44	467-00 Measuring & Regulating Equipment	29,406	7.55%	2,220	-	-	-	8,486	10,706
45	467-10 Telemetering	8,593	1.33%	114	-	-	-	6,196	6,310
46	467-20 Measuring & Regulating Equipment - Byron Cr	39	4.21%	2	-	-	-	9	11
47	468-00 Communication Structures & Equipment	346	5.32%	18	-	-	-	295	313
48	469-00 Other Transmission Equipment	-	0.00%	-	-	-	-	-	-
49	TOTAL TRANSMISSION PLANT	982,643		22,118	-	(1,367)	-	260,529	281,280

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision: 2011 (Cr.)	Provision: Adjust-ments	Provision: Retirements	Provision: Retirement Costs	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	470-00 Land in Fee Simple	$3,418	0.00%	$0	$0	$0	$0	$30	$30
3	472-00 Structures & Improvements	14,696	3.78%	556	-	-	-	3,787	4,343
4	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	-	21	26
5	473-00 Services	672,119	3.38%	22,718	-	(6,966)	(8,525)	83,475	90,702
6	473-00 Services - LILO	43,229	3.30%	1,427	-	-	-	17,506	18,933
7	474-00 House Regulators & Meter Installations	138,035	5.21%	7,192	-	(10,098)	(500)	(5,649)	(9,055)
8	474-00 House Regulators & Meter Installations - LILO	16,070	2.19%	352	-	-	-	8,624	8,976
9	475-00 Mains	871,791	2.26%	19,702	-	(1,983)	(500)	252,518	269,737
10	475-00 Mains - LILO	39,704	2.40%	953	-	-	-	16,558	17,511
11	476-00 Compressor Equipment	571	25.04%	143	-	-	-	546	689
12	477-00 Measuring & Regulating Equipment	88,550	5.72%	5,065	-	(716)	(107)	16,783	21,025
13	477-00 Telemetering	6,232	0.25%	16	-	(11)	-	6,390	6,395
14	477-10 Measuring & Regulating Equipment - Byron Cre	163	0.00%	-	-	-	-	200	200
15	478-10 Meters	187,822	5.31%	9,973	-	(8,277)	(500)	39,791	40,987
16	478-11 Meters - LILO	10,027	3.29%	330	-	-	-	4,397	4,727
17	478-20 Instruments	11,251	4.03%	453	-	-	-	3,268	3,721
18	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-	-
19		2,103,784		68,885	-	(28,051)	(10,132)	448,245	478,947
20									
21	**GENERAL PLANT & EQUIPMENT**								
22	480-00 Land in Fee Simple	22,096	0.00%	-	-	-	-	13	13
23	481-00 Land Rights	-	0.00%	-	-	-	-	-	-
24	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-	-
25	- Frame Buildings	5,286	3.67%	194	-	-	-	1,768	1,962
26	- Masonry Buildings	87,190	4.37%	3,810	-	-	-	12,743	16,553
27	- Leasehold Improvement	667	10.00%	67	-	-	-	362	429
28	Office Equipment & Furniture	-	0.00%	-	-	-	-	-	-
29	483-30 GP Office Equipment	4,012	6.67%	268	-	(991)	-	2,872	2,149
30	483-40 GP Furniture	19,830	5.00%	991	-	(1,230)	-	12,346	12,107
31	483-10 GP Computer Hardware	18,979	20.00%	3,796	-	-	-	7,213	11,009
32	483-20 GP Computer Software	734	20.00%	147	-	(198)	-	594	543
33	483-21 GP Computer Software	-	0.00%	-	-	-	-	-	-
34	484-00 Transportation Equipment	4,712	6.16%	290	-	-	-	924	1,214
35	484-00 Vehicles - Leased	28,198	Lease Term	2,709	-	(1,641)	-	14,209	15,277
36	485-10 Heavy Work Equipment	209	5.65%	12	-	-	-	124	136
37	485-20 Heavy Mobile Equipment	606	6.43%	39	-	-	-	129	168
38	486-00 Small Tools & Equipment	33,867	5.00%	1,693	-	-	-	16,587	18,280
39	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	-	8	10
40	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-	-
41	488-00 Communications Equipment	-	0.00%	-	-	-	-	-	-
42	- Telephone	10,975	6.67%	732	-	(1,596)	-	6,711	5,847
43	- Radio	4,706	6.67%	314	-	(954)	-	2,164	1,524
44	489-00 Other General Equipment	-	0.00%	-	-	-	-	-	-
45	TOTAL GENERAL PLANT	242,088		15,064	-	(6,610)	-	78,767	87,221
46									
47	**UNCLASSIFIED PLANT**								
48	499 Plant Suspense	-	0.00%	-	-	-	-	(7)	(7)
49	TOTAL UNCLASSIFIED PLANT	-		-	-	-	-	(7)	(7)
50									
51	TOTALS	$3,492,582		$116,698	$0	($48,015)	($10,132)	$840,835	$899,386
52		(X-Ref - Tab C-13, Schedule 47)						(X-Ref - Tab C-13, Schedule 9)	
53	Less: Capital Lease Vehicle Depreciation allocated to Capital Projects			(1,002)					
54									
55	**Net Depreciation Expense**			$115,696					
56				(X-Ref - Tab C-13, Schedule 34)					

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Balance 12/31/2009	Adjustment	2010 Additions	2010 Retirements	Balance 12/31/2010	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$141,389	$0	$6,356	$0	$147,745	
4							
5	Transmission Contributions	10,915	-	4,550	-	15,465	
6							
7	Others	-	-	-	-	-	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	24,541	-	-	(3,934)	20,607	
11							
12	TOTAL Contributions	176,845	-	10,906	(3,934)	183,817	(X-Ref - Tab C-13, Schedule 8)
13							(X-Ref - Tab C-13, Schedule 41)
14							
15							
16	**Amortization**						
17							
18	Distribution Contributions	(32,291)	-	(3,764)	-	(36,055)	
19							
20	Transmission Contributions	-	-	(263)	-	(263)	
21							
22	Others	(1)	-	-	-	(1)	
23							
24	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
25	- Infrastructure/Custom	(11,854)	-	(2,822)	3,934	(10,742)	
26							
27	TOTAL Amortization	(44,146)	-	(6,849)	3,934	(47,061)	(X-Ref - Tab C-13, Schedule 8)
28							(X-Ref - Tab C-13, Schedule 41)
29	**NET CONTRIBUTIONS**	$132,699	$0	$4,057	$0	$136,756	

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	Adjustment	2011 Additions	2011 Retirements	Balance 12/31/2011	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$147,745	$0	$5,990	$0	$153,735	
4							
5	Transmission Contributions	15,465	-	8,333	-	23,798	
6							
7	Others	-	-	-	-	-	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	20,607	-	-	(3,494)	17,113	
11							
12	TOTAL Contributions	183,817	-	14,323	(3,494)	194,646	(X-Ref - Tab C-13, Schedule 9)
13							(X-Ref - Tab C-13, Schedule 42)
14							
15							
16	**Amortization**						
17							
18	Distribution Contributions	(36,055)	-	(3,925)	-	(39,980)	
19							
20	Transmission Contributions	(263)	-	(391)	-	(654)	
21							
22	Others	(1)	-	-	-	(1)	
23							
24	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
25	- Infrastructure/Custom	(10,742)	-	(2,358)	3,494	(9,606)	
26							
27	TOTAL Amortization	(47,061)	-	(6,674)	3,494	(50,241)	(X-Ref - Tab C-13, Schedule 9)
28							(X-Ref - Tab C-13, Schedule 42)
29	**NET CONTRIBUTIONS**	$136,756	$0	$7,649	$0	$144,405	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Forecast Balance 12/31/2009	Opening Balance Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2010	Mid-Year Average 2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Commodity Cost Reconciliation Account (CCRA)	($22,742.7)	$0.0	$31,808.0	($9,065.3)	$22,742.7	$0.0	$0.0	$0.0	$0.0	($11,371.4)
3	CCRA Interest	(895.9)		1,253.0	(357.1)	895.9	-	-	-	(0.0)	(448.0)
4	Midstream Cost Reconciliation Account (MCRA)	36,423.3		(50,941.7)	14,518.4	(36,423.3)	-	-	-	(0.0)	18,211.7
5	MCRA Interest	(1,779.2)		2,488.4	(709.2)	1,779.2	-	-	-	-	(889.6)
6	Revenue Stabilization Adjustment Mechanism (RSAM)	(13,165.6)		-	-	-	-	6,137.8	(1,749.3)	(8,777.1)	(10,971.4)
7	RSAM Interest	(38.4)		(5.3)	1.5	(3.8)	-	18.3	(5.2)	(29.1)	(33.8)
8	Revelstoke Propane Cost Deferral Account	(38.8)		54.3	(15.5)	38.8	-	-	-	(0.0)	(19.4)
9	SCP Mitigation Revenues Variance Account	(4,118.1)	(1,538.2)	-	-	-	1,723.2	-	-	(3,933.1)	(4,794.7)
10	SCP West to East Transmission	(1,538.2)	1,538.2	-	-	-	-	-	-	-	-
11											
12	Energy Policy Related										
13	Energy Efficiency & Conservation (EEC)	6,370.2		25,845.0	(7,365.8)	18,479.2	(1,012.0)	-	-	23,837.4	15,103.8
14	NGV Conversion Grants	136.9		77.5	(22.1)	55.4	(43.5)	-	-	148.8	142.9
15											
16	Non-Controllable Items										
17	Property Tax Deferral	(743.8)		-	-	-	398.1	-	-	(345.7)	(544.8)
18	Insurance Variance	(686.0)		-	-	-	686.0	-	-	-	(343.0)
19	Pension & OPEB Variance	(686.4)		-	-	-	686.4	-	-	-	(343.2)
20	BCUC Levies Variance	(262.0)		-	-	-	262.0	-	-	-	(131.0)
21	Interest Variance	(2,232.2)		-	-	-	633.9	-	-	(1,598.3)	(1,915.3)
22	Interest Variance - Funding benefits via Customer Deposits	214.2		-	-	-	(13.1)	-	-	201.1	207.7
23	Olympics Security Costs Deferral	522.8		2,651.6	(755.7)	1,895.9	-	-	-	2,418.7	1,470.8
24	IFRS Conversion Costs	399.5		265.3	(75.6)	189.7	-	-	-	589.2	494.4
25											
26	Cost of Current Applications										
27	2009 ROE & Cost of Capital Application	$441.0		$0.0	$0.0	$0.0	($88.2)	$0.0	$0.0	$352.8	$396.9
28	2010-2011 Revenue Requirement Application	795.2		-	-	-	(397.6)	-	-	397.6	596.4
29	CCE CPCN Application	189.0		-	-	-	(37.8)	-	-	151.2	170.1
30											
31	Other										
32	IFRS Transitional Adjustments	-		(7,602.7)	-	(7,602.7)	-	-	-	(7,602.7)	(7,602.7)
33	OPEB Funding	(32,551.8)	32,551.8	-	-	-	-	-	-	-	(16,275.9)
34	Pension & OPEB Funding	-	(32,551.8)	20,476.7	-	20,476.7	-	-	-	(12,075.1)	(6,037.6)
35											
36	Residual Deferred Charges										
37	SCP Tax Reassessment	7,408.3		-	-	-	-	-	-	7,408.3	7,408.3
38	Deferred Service Line Installation Fee	1,442.9		(1,442.9)	-	(1,442.9)	-	-	-	-	-
39	Earnings Sharing Mechanism	(13,123.6)		3,372.0	(961.0)	2,411.0	-	6,168.7	(1,758.1)	(6,302.0)	(9,712.8)
40	CCT Assessment	(2.5)		-	-	-	2.5	-	-	-	(1.3)
41	Carbon Tax Implementation	(95.0)		-	-	-	95.0	-	-	-	(47.5)
42	TGS Amalgamation	132.0		-	-	-	(132.0)	-	-	-	66.0
43	TGS O&M Variance	352.0		-	-	-	(352.0)	-	-	-	176.0
44	Carbon Tax Cost of Service	(44.0)		-	-	-	44.0	-	-	(0.0)	(22.0)
45	OSC Certification Compliance	91.1		-	-	-	(91.1)	-	-	-	45.6
46	Bad Debt Allowance for Rates 14 & 14A	(140.2)	140.2	-	-	-	-	-	-	-	-
47											
48	Total Deferred Charges for Rate Base	($39,966.0)	$140.2	$28,299.2	($4,807.4)	$23,491.8	$2,363.8	$12,324.8	($3,512.6)	($5,158.0)	($27,014.8)
49							(X-Ref - Tab C-13, Schedule 33)			(X-Ref - Tab C-13, Schedule 8)	

TERASEN GAS INC.

June 12, 2009 Advance Materials

Section C
Tab 13
Schedule 55

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Forecast Balance 12/31/2010	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2011	Mid-Year Average 2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Margin Related									
2	Commodity Cost Reconciliation Account (CCRA)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
3	CCRA Interest	(0.0)	-	-	-	-	-	-	(0.0)	-
4	Midstream Cost Reconciliation Account (MCRA)	(0.0)	-	-	-	-	-	-	(0.0)	-
5	MCRA Interest	-	-	-	-	-	-	-	-	-
6	Revenue Stabilization Adjustment Mechanism (RSAM)	(8,777.1)	-	-	-	-	5,970.8	(1,582.3)	(4,388.6)	(6,582.9)
7	RSAM Interest	(29.1)	199.0	(52.7)	146.3	-	19.3	(5.1)	131.4	51.2
8	Revelstoke Propane Cost Deferral Account	(0.0)	-	-	-	-	-	-	(0.0)	-
9	SCP Mitigation Revenues Variance Account	(3,933.1)	-	-	-	1,735.9	-	-	(2,197.2)	(3,065.2)
10	SCP West to East Transmission	-	-	-	-	-	-	-	-	-
11										
12	Energy Policy Related									
13	Energy Efficiency & Conservation (EEC)	23,837.4	29,619.0	(7,849.0)	21,770.0	(2,524.9)	-	-	43,082.5	33,460.0
14	NGV Conversion Grants	148.8	255.0	(67.6)	187.4	(51.1)	-	-	285.1	217.0
15										
16	Non-Controllable Items									
17	Property Tax Deferral	(345.7)	-	-	-	184.2	-	-	(161.5)	(253.6)
18	Insurance Variance	-	-	-	-	-	-	-	-	-
19	Pension & OPEB Variance	-	-	-	-	-	-	-	-	-
20	BCUC Levies Variance	-	-	-	-	-	-	-	-	-
21	Interest Variance	(1,598.3)	-	-	-	721.6	-	-	(876.7)	(1,237.5)
22	Interest Variance - Funding benefits via Customer Deposits	201.1	-	-	-	(13.1)	-	-	188.0	194.6
23	Olympics Security Costs Deferral	2,418.7	-	-	-	(806.2)	-	-	1,612.5	2,015.6
24	IFRS Conversion Costs	589.2	119.3	(31.6)	87.7	(196.4)	-	-	480.5	534.9
25										
26	Cost of Current Applications									
27	2009 ROE & Cost of Capital Application	$352.8	$0.0	$0.0	$0.0	($88.2)	$0.0	$0.0	$264.6	$308.7
28	2010-2011 Revenue Requirement Application	397.6	-	-	-	(397.6)	-	-	-	198.8
29	CCE CPCN Application	151.2	-	-	-	(37.8)	-	-	113.4	132.3
30										
31	Other									
32	IFRS Transitional Adjustments	(7,602.7)	68,819.0	-	68,819.0	-	-	-	61,216.3	26,806.8
33	OPEB Funding	-	-	-	-	-	-	-	-	-
34	Pension & OPEB Funding	(12,075.1)	(69,232.0)	-	(69,232.0)	-	-	-	(81,307.1)	(46,691.1)
35										
36	Residual Deferred Charges									
37	SCP Tax Reassessment	7,408.3	-	-	-	-	-	-	7,408.3	7,408.3
38	Deferred Service Line Installation Fee	-	-	-	-	-	-	-	-	-
39	Earnings Sharing Mechanism	(6,302.0)	1,686.0	(446.8)	1,239.2	-	6,888.2	(1,825.4)	-	(3,151.0)
40	CCT Assessment	-	-	-	-	-	-	-	-	-
41	Carbon Tax Implementation	-	-	-	-	-	-	-	-	-
42	TGS Amalgamation	-	-	-	-	-	-	-	-	-
43	TGS O&M Variance	-	-	-	-	-	-	-	-	-
44	Carbon Tax Cost of Service	(0.0)	-	-	-	-	-	-	(0.0)	-
45	OSC Certification Compliance	-	-	-	-	-	-	-	-	-
46	Bad Debt Allowance for Rates 14 & 14A	-	-	-	-	-	-	-	-	-
47										
48	Total Deferred Charges for Rate Base	($5,158.0)	$31,465.3	($8,447.7)	$23,017.6	($1,473.6)	$12,878.3	($3,412.8)	$25,851.5	$10,346.9
49						(X-Ref - Tab C-13, Schedule 34)			(X-Ref - Tab C-13, Schedule 9)	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Existing 2009 Rates	2010 Revised Revenue	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	($14,650)	$1,924	$2,324	$16,974	- Tab C-13, Schedule 58
4						
5	Customer Deposits	(3,474)	0	-	3,474	
6						
7	Less - Funds Available:					
8						
9	Reserve for Bad Debts	(5,990)	(5,940)	(5,940)	50	
10						
11	Withholdings From Employees	(3,069)	(3,162)	(3,162)	(93)	
12						
13	Subtotal	(27,183)	(7,178)	(6,778)	20,405	(X-Ref - Tab C-13, Schedule 8)
14						(X-Ref - Tab C-13, Schedule 41)
15	**Other Working Capital Items**					
16	Construction Advances	(670)	(670)	(670)	-	
17	Transmission Line Pack Gas	3,430	2,413	2,413	(1,017)	
18	Gas in Storage	111,734	100,494	100,494	(11,240)	
19	Inventory - Materials & Supplies	1,207	1,202	1,202	(5)	
20						
21	Subtotal	115,701	103,439	103,439	(12,262)	(X-Ref - Tab C-13, Schedule 8)
22						(X-Ref - Tab C-13, Schedule 41)
23	Total	$88,518	$96,261	$96,661	$8,143	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Existing 2009 Rates	2011 Revised Revenue	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$2,324	$2,759	$3,186	$862	- Tab C-13, Schedule 58
4						
5	Customer Deposits	0	0	-	0	
6						
7	Less - Funds Available:					
8						
9	Reserve for Bad Debts	(5,940)	(6,063)	(6,063)	(123)	
10						
11	Withholdings From Employees	(3,162)	(3,256)	(3,256)	(94)	
12						
13	Subtotal	(6,778)	(6,560)	(6,133)	645	(X-Ref - Tab C-13, Schedule 9)
14						(X-Ref - Tab C-13, Schedule 42)
15	**Other Working Capital Items**					
16	Construction Advances	(670)	(670)	(670)	0	
17	Transmission Line Pack Gas	2,413	4,731	4,731	2,318	
18	Gas in Storage	100,494	114,804	114,804	14,310	
19	Inventory - Materials & Supplies	1,202	1,226	1,226	24	
20						
21	Subtotal	103,439	120,091	120,091	16,652	(X-Ref - Tab C-13, Schedule 9)
22						(X-Ref - Tab C-13, Schedule 42)
23	Total	$96,661	$113,531	$113,958	$17,297	

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009 Days	2009 Expenses	2009 Cash Working Capital	2010 Days	2010 Expenses	2010 Cash Working Capital	2011 Days	2011 Expenses	2011 Cash Working Capital	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**CASH WORKING CAPITAL**										
2											
3	Revenue Lag Days	35.0			38.8			38.8			- Tab C-13, Schedule 59
4	Expense Lead Days	39.1			38.3			38.1			- Tab C-13, Schedule 60
5											(X-Ref - Tab C-13, Schedule 56)
6	Net Lead/(Lag) Days	(4.1)	$1,304,216	($14,650)	0.5	$1,404,349	$1,924	0.7	$1,438,445	$2,759	(X-Ref - Tab C-13, Schedule 57)
7											
8											
9											
10	**CASHWORKING CAPITAL, REVISED RATES**										
11											
12	Revenue Lag Days	35.0			38.8			38.8			- Tab C-13, Schedule 59
13	Expense Lead Days	39.1			38.2			38.0			- Tab C-13, Schedule 60
14											(X-Ref - Tab C-13, Schedule 56)
15	Net Lead/(Lag) Days	(4.1)	$1,304,216	($14,650)	0.6	$1,413,479	$2,324	0.8	$1,453,799	$3,186	(X-Ref - Tab C-13, Schedule 57)
16											
17											
18											
19	**CASH WORKING CAPITAL CHANGE**			$0			$400			$427	
20											
21											
22											
23	Cash working capital = Col. 2 x Col. 3 / 365 days										

TERASEN GAS INC. June 12, 2009 Advance Materials Section C
Tab 13
Schedule 59

CASH WORKING CAPITAL
LAG TIME FROM DATE OF PAYMENT TO RECEIPT OF CASH
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

		2009			2010			2011			
Line No.	Particulars	Revenue At 2009 Rates	Lag Days Service to Collection	Dollar Days	Revenue At 2009 Rates	Lag Days Service to Collection	Dollar Days	Revenue At 2009 Rates	Lag Days Service to Collection	Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**REVENUE**										
2											- Tab C-13, Schedule 22
3	Gas Sales and Transportation Service Revenue										- Tab C-13, Schedule 24
4	Residential and Commercial	$1,345,174	34.6	$46,543,003	$1,384,580	38.3	$53,086,028	$1,386,315	38.3	$53,151,466	
5	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	78,978	41.0	3,238,086	76,201	45.0	3,430,546	76,002	45.0	3,421,537	
6	NGV Fuel - Stations	1,076	38.7	41,657	1,044	41.7	43,552	1,044	41.7	43,552	
7											
8	Rates 22, Burrard, TGVI (Oth Rev), SCP (Oth Rev)	40,797	37.8	1,542,123	42,448	42.6	1,806,347	44,411	42.4	1,881,433	
9											
10	Total Gas Sales	1,466,025	35.0	51,364,868	1,504,274	38.8	58,366,473	1,507,772	38.8	58,497,988	
11					(X-Ref - Tab C-13, Schedule 2)			(X-Ref - Tab C-13, Schedule 3)			- Tab C-13, Schedule 26
12	Other Revenues										- Tab C-13, Schedule 27
13	Late Payment Charges	2,879	26.7	76,869	2,982	38.3	114,207	2,987	38.3	114,402	
14	Returned Cheque Charges	84	31.8	2,671	82	38.3	3,140	82	38.3	3,140	
15	Connection Charges	3,105	37.3	115,817	2,879	38.3	110,273	2,905	38.3	111,266	
16	Other Utility Income	277	34.9	9,667	203	38.4	7,791	132	38.2	5,040	
17											
18											
19	Total Revenue	$1,472,370	35.0	$51,569,893	$1,510,420	38.8	$58,601,884	$1,513,878	38.8	$58,731,836	
20											
21											
22	**REVENUE, REVISED RATES**										
23											- Tab C-13, Schedule 22
24	Gas Sales and Transportation Service Revenue										- Tab C-13, Schedule 24
25	Residential and Commercial	$1,345,174	34.6	$46,543,003	$1,408,658	38.3	$54,009,463	$1,429,393	38.3	$54,803,566	
26	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	78,978	41.0	3,238,086	79,166	45.0	3,564,433	81,304	45.0	3,660,955	
27	NGV Fuel - Stations	1,076	38.7	41,657	1,065	41.7	44,427	1,081	41.7	45,095	
28											
29	Rates 22, Burrard, TGVI, SCP (Other)	40,797	37.8	1,542,123	43,249	42.6	1,842,551	45,840	42.5	1,946,023	
30											
31	Total Gas Sales	1,466,025	35.0	51,364,868	1,532,139	38.8	59,460,874	1,557,618	38.8	60,455,639	
32											- Tab C-13, Schedule 26
33	Other Revenues										- Tab C-13, Schedule 27
34	Late Payment Charges	2,879	26.7	76,869	2,982	38.3	114,207	2,987	38.3	114,402	
35	Returned Cheque Charges	84	31.8	2,671	82	38.3	3,140	82	38.3	3,140	
36	Connection Charges	3,105	37.3	115,817	2,879	38.3	110,273	2,905	38.3	111,266	
37	Other Utility Income	277	34.9	9,667	203	38.4	7,791	132	38.2	5,040	
38											
39											
40	Total Revenue	$1,472,370	35.0	$51,569,893	$1,538,285	38.8	$59,696,285	$1,563,724	38.8	$60,689,487	

CASH WORKING CAPITAL
LEAD TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009 Amount	2009 Lead Days Expense to Payment	2009 Dollar Days	2010 Amount	2010 Lead Days Expense to Payment	2010 Dollar Days	2011 Amount	2011 Lead Days Expense to Payment	2011 Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**EXPENSES**										
2											
3	Operating And Maintenance										- Tab C-13, Schedule 4
4	Expenses	$166,966	19.3	$3,222,444	$192,823	25.5	$4,916,987	$201,617	25.5	$5,141,234	- Tab C-13, Schedule 5
5											- Tab C-13, Schedule 4
6	Gas Purchases	931,546	40.7	37,913,922	975,597	40.2	39,218,999	976,614	40.2	39,259,883	- Tab C-13, Schedule 5
7											
8	Taxes Other Than Income										- Tab C-13, Schedule 31
9	Property Taxes	47,593	4.0	190,372	49,193	2.0	98,386	50,211	2.0	100,422	- Tab C-13, Schedule 32
10	Franchise Fees	10,049	430.0	4,321,070	10,121	420.3	4,253,857	10,147	420.3	4,264,784	
11	Carbon Tax	71,835	43.6	3,131,995	97,701	29.1	2,843,110	125,507	29.1	3,652,264	
12	GST - Net	12,533	7.2	90,222	12,858	38.8	498,877	12,887	38.8	500,018	
13	PST	40,685	43.6	1,773,866	42,373	37.1	1,572,039	43,014	37.1	1,595,820	
14	Income Tax	23,011	15.2	349,767	23,682	15.2	359,966	18,448	15.2	280,410	- Tab C-13, Schedule 6
15											- Tab C-13, Schedule 7
16	Total	$1,304,217	39.1	$50,993,658	$1,404,348	38.3	$53,762,221	$1,438,445	38.1	$54,794,835	
17											
18											
19	**EXPENSES, REVISED RATES**										
20											
21	Operating And Maintenance										- Tab C-13, Schedule 4
22	Expenses	$166,966	19.3	$3,222,444	$192,823	25.5	$4,916,987	$201,617	25.5	$5,141,234	- Tab C-13, Schedule 5
23											- Tab C-13, Schedule 4
24	Gas Purchases	931,546	40.7	37,913,922	975,597	40.2	39,218,999	976,614	40.2	39,259,883	- Tab C-13, Schedule 5
25											
26	Taxes Other Than Income										- Tab C-13, Schedule 31
27	Property Taxes	47,593	4.0	190,372	49,193	2.0	98,386	50,211	2.0	100,422	- Tab C-13, Schedule 32
28	Franchise Fees	10,049	430.0	4,321,070	10,321	420.3	4,337,917	10,506	420.3	4,415,672	
29	Carbon Tax	71,835	43.6	3,131,995	97,701	29.1	2,843,110	125,507	29.1	3,652,264	
30	GST - Net	12,533	7.2	90,222	13,095	38.8	508,099	13,313	38.8	516,559	
31	PST	40,685	43.6	1,773,866	43,126	37.1	1,599,975	44,376	37.1	1,646,349	
32	Income Tax	23,011	15.2	349,767	31,622	15.2	480,654	31,654	15.2	481,141	- Tab C-13, Schedule 6
33											- Tab C-13, Schedule 7
34	Total	$1,304,217	39.1	$50,993,658	$1,413,479	38.2	$54,004,127	$1,453,799	38.0	$55,213,524	

FUTURE INCOME TAX LIABILITY / ASSET
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009	2010	2011
	(1)	(2)	(3)	(4)
1	Property Plant & Equipment			
2	Net Book Value *	($2,447,020)	($2,535,462)	($2,625,708)
3	Less: Undepreciated Capital Cost	(1,712,991)	(1,760,477)	(1,853,515)
4		(734,029)	(774,985)	(772,193)
5	Weighted Average Future Tax Rate	25%	25%	25%
6		(184,037)	(194,075)	(193,048)
7				
8	Total FIT Liability- After Tax (PP&E)	(184,037)	(194,075)	(193,048)
9	Total FIT Liability- After Tax (Non-PP&E)	(24,298)	(23,948)	(27,038)
10	Total FIT Liability- After Tax	(208,335)	(218,023)	(220,086)
11				
12	Tax Gross Up	(69,713)	(72,839)	(73,362)
13				
14	FIT Liability/Asset - End of Year	(278,048)	(290,862)	(293,448)
15				
16	FIT Liability/Asset - Opening Balance	(278,048)	(278,048)	(290,862)
17				
18	FIT Liability/Asset - Mid Year	(278,048)	(284,455)	(292,155)
19		(X-Ref - Tab C-13, Schedule 8)	(X-Ref - Tab C-13, Schedule 9)	
20			(X-Ref - Tab C-13, Schedule 41)	
21	Note: * Excludes Land, Software CIAC, and WIP.		(X-Ref - Tab C-13, Schedule 42)	

TERASEN GAS INC.
RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Reference	-------- Capitalization -------- Amount		%	Average Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2010 AT 2009 RATES							
2	Long-Term Debt	- Tab C-13, Schedule 64		$1,580,370	62.330%	6.868%	4.280%	$108,533
3	Unfunded Debt			67,443	2.660%	2.250%	0.060%	1,517
4	Common Equity			887,674	35.010%	6.227%	2.180%	55,275
5								
6		- Tab C-13, Schedule 8		$2,535,487	100.000%		6.520%	$165,325
7								
8	2010 REVISED RATES - FORECAST							
9	Long-Term Debt			$1,580,370	62.320%	6.868%	4.280%	$108,533
10	Unfunded Debt		$67,443					
11	Adjustment, Revised Rates		260	67,703	2.670%	2.250%	0.060%	1,523
12	Common Equity			887,814	35.010%	8.470%	2.970%	75,198
13								
14		- Tab C-13, Schedule 8		$2,535,887	100.000%		7.305%	$185,254
15							(X-Ref - Tab C-13, Schedule 4)	

($000s)

Line No.	Particulars	Reference	-------- Capitalization --------	Amount	%	Average Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2011 At 2010 Rates							
2	Long-Term Debt	- Tab C-13, Schedule 65		$1,631,277	62.260%	6.878%	4.282%	$112,204
3	Unfunded Debt			71,405	2.730%	4.500%	0.123%	3,213
4	Common Equity			917,232	35.010%	4.470%	1.565%	41,000
5								
6		- Tab C-13, Schedule 9		$2,619,914	100.000%		5.970%	$156,417
7								
8	2011 REVISED RATES - FORECAST							
9	Long-Term Debt			$1,631,277	62.250%	6.878%	4.282%	$112,204
10	Unfunded Debt		$71,405					
11	Adjustment, Revised Rates		278	71,683	2.740%	4.500%	0.123%	3,226
12	Common Equity			917,381	35.010%	8.470%	2.965%	77,702
13								
14		- Tab C-13, Schedule 9		$2,620,341	100.000%		7.370%	$193,132
15							(X-Ref - Tab C-13, Schedule 5)	

TERASEN GAS INC.

June 12, 2009 Advance Materials — Section C
Tab 13
Schedule 64

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$58,943	$855 *	$63,128	12.054%	$63,983	$7,713	
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	155,046	10.461%	157,274	16,452	
3											
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710	7.073%	150,000	10,610	
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085	6.598%	150,000	9,897	
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337	5.980%	150,000	8,970	
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216	5.595%	120,000	6,714	
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697	6.067%	250,000	15,168	
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,389	247,611	5.868%	250,000	14,670	
10	2009 Medium Term Debt Issue- Series 24 (includes replacement for Series E)	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000	6.627%	100,000	6,627	
11	2009 Medium Term Debt Issue- Series 25	1-Dec-2009	1-Dec-2019	5.650%	100,000	1,000	99,000	5.783%	100,000	5,783	
12									-	-	
13											
14	LILO Obligations - Kelowna							5.905%	26,735	1,579	
15	LILO Obligations - Nelson							7.011%	4,258	299	
16	LILO Obligations - Vernon							8.150%	12,731	1,038	
17	LILO Obligations - Prince George							7.171%	32,685	2,344	
18	LILO Obligations - Creston							6.418%	3,098	199	
19											
20	Vehicle Lease Obligation							5.380%	12,740	685	
21											
22									$1,583,504	$108,748	
23											
24	Sub-Total								$1,583,504	$108,748	
25	Less - Fort Nelson Division Portion of Long Term Debt								(3,134)	(215)	
26	Total								$1,580,370	$108,533	
27								(X-Ref - Tab C-13, Schedule 10)	, (X-Ref - Tab C-13, Schedule 62)		
28	*Includes adjustment of $5,049 for BC Hydro Premium								Average Embedded Cost	6.868%	

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$58,943	$855	$65,824 *	12.054%	$66,679	$8,037	
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	155,046	10.461%	157,274	16,452	
3											
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710	7.073%	150,000	10,610	
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085	6.598%	150,000	9,897	
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337	5.980%	150,000	8,970	
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216	5.595%	120,000	6,714	
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697	6.067%	250,000	15,168	
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,389	247,611	5.868%	250,000	14,670	
10	2009 Medium Term Debt Issue- Series 24 (includes replacement for Series E)	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000	6.627%	100,000	6,627	
11	2009 Medium Term Debt Issue- Series 25	1-Dec-2009	1-Dec-2019	5.650%	100,000	1,000	99,000	5.783%	100,000	5,783	
12	2011 Medium Term Debt Issue- Series 26	1-Jul-2011	1-Jul-2021	6.129%	100,000	1,000	99,000	6.265%	50,411	3,158	
13											
14	LILO Obligations - Kelowna							5.919%	25,729	1,523	
15	LILO Obligations - Nelson							7.093%	4,110	292	
16	LILO Obligations - Vernon							8.242%	12,267	1,011	
17	LILO Obligations - Prince George							7.256%	31,571	2,291	
18	LILO Obligations - Creston							6.496%	2,996	195	
19											
20	Vehicle Lease Obligation							7.631%	13,455	1,027	
21											
22									$1,634,492	$112,425	
23											
24	Sub-Total								$1,634,492	$112,425	
25	Less - Fort Nelson Division Portion of Long Term Debt								(3,215)	(221)	
26	Total								$1,631,277	$112,204	
27								(X-Ref - Tab C-13, Schedule 11)	(X-Ref - Tab C-13, Schedule 63)		
28	*Includes adjustment of $7,772 for BC Hydro Premium								Average Embedded Cost	6.878%	

GROSS MARGIN RECONCILIATION WITH 2010 RATES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line		Proposed Base Delivery Rate			Approved Basic Charge & Admin Fee				Proposed Demand Charge			Collected	Required	Margin
No.	Particulars	Rate	Terajoules	($000)	Rate	Customers	Adj Factor	($000)	Rate	Terajoules	($000)	Margin	Margin	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	**NON-BYPASS**													
2	Core Sales													
3	Schedule 1 - Residential	3.213	67,829.2	$217,935	11.840	756,017	-1.20%	$106,130	-	-	$0	$324,065	$324,033	$32
4	Schedule 2 - Small Commercial	2.667	24,374.3	65,006	24.840	76,536	-4.54%	21,777	-	-	-	86,783.7	86,770.7	13.0
5	Schedule 3 - Large Commercial	2.282	16,818.6	38,380	132.520	5,022	-0.50%	7,945	-	-	-	46,325.3	46,309.5	15.8
6	Total Schedules 1 , 2 and 3		109,022.1	321,322		837,575		135,853		-	-	457,174.1	457,113.6	60.5
7														
8	Schedule 4 - Seasonal Service	0.838	184.6	155	439.000	16		83	-	-	-	238.1	261.9	(23.8)
9	Schedule 5 - General Firm Service	0.635	3,098.5	1,968	587.000	283		1,993	15.690	207	3,247	7,207.9	7,245.6	(37.7)
10														
11	Industrials													
12	Schedule 7 - Interruptible	1.057	14.2	15	880.000	2		21	-	-	-	36.1	37.3	(1.2)
13														
14	Schedule 6 - N G V Fuel - Stations	3.600	103.8	374	61.000	32		23	-	-	-	397.1	397.6	(0.5)
15														
16	Total Industrials		103.8	374		32		23		-	-	397.1	397.6	(0.5)
17														
18	Total Core Sales		112,423.2	323,832		837,908		137,953		207	3,247	465,053.3	465,056.0	(2.7)
19														
20	Transportation Service													
21	Schedule 22 - Firm Service	0.086	7,136.8	616.0	4,783.000	13		746	11.867	255.8	3,035.5	4,397.6	5,099.7	(702.1)
22	- Interruptible Service	0.782	11,849.7	9,260.6	3,742.000	22		988	-	14.5	-	10,248.5	10,103.2	145.3
23	Schedule 23 - Large Commercial	2.282	6,134.0	13,998	210.520	1,309		3,308	-	-	-	17,305.7	17,257.0	48.7
24	Schedule 25 - Firm Service	0.635	12,466.5	7,916	665.000	579		4,620	15.690	813	12,751	25,287.8	24,917.6	370.2
25	Schedule 27 - Interruptible Service	1.057	5,183.5	5,479	958.000	99		1,138	-	-	-	6,616.8	6,569.0	47.8
26														
27	Total T-Service		42,770.5	37,269		2,022		10,800		1,083	15,787	63,856.4	63,946.5	(90.1)
28														
29	Total Non-Bypass Sales & Transportation Service		155,193.7	361,101.8		839,930		148,753.3		1,290	19,033.5	528,909.7	529,002.5	(92.8)
30			(X-Ref - Tab C-13, Schedule 14)			(X-Ref - Tab C-13, Schedule 22)				(X-Ref - Tab C-13, Schedule 22 Columns 6 + 8, line 27)				

TERASEN GAS INC.

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Section C
Tab 13
Schedule 67

GROSS MARGIN RECONCILIATION WITH 2011 RATES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line		Proposed Base Delivery Rate			Approved Basic Charge & Admin Fee				Proposed Demand Charge			Collected	Required	Margin
No.	Particulars	Rate	Terajoules	($000)	Rate	Customers	Adj Factor	($000)	Rate	Terajoules	($000)	Margin	Margin	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	**NON-BYPASS**													
2	Core Sales													
3	Schedule 1 - Residential	3.413	67,190.5	$229,321	11.840	760,873	-1.20%	$106,811	-	-	$0	336,132.5	336,140.4	(7.9)
4	Schedule 2 - Small Commercial	2.814	24,603.1	69,233	24.840	77,252	-4.54%	21,981	-	-	-	91,214.4	91,216.5	(2.1)
5	Schedule 3 - Large Commercial	2.397	17,168.5	41,153	132.520	5,126	-0.51%	8,110	-	-	-	49,262.5	49,230.9	31.6
6	Total Schedules 1 , 2 and 3		108,962.1	339,707		843,250		136,902		-	-	476,609.4	476,587.8	21.6
7														
8	Schedule 4 - Seasonal Service	0.878	184.6	162	256.080	16		49	-	-	-	210.7	272.9	(62.2)
9	Schedule 5 - General Firm Service	0.668	3,061.2	2,045	587.000	283		1,993	16.708	207	3,458	7,495.9	7,520.3	(24.4)
10														
11	Industrials													
12	Schedule 7 - Interruptible	1.111	14.2	16	880.000	2		21	-	-	-	36.9	38.3	(1.4)
13														
14	Schedule 6 - N G V Fuel - Stations	3.754	103.8	390	61.000	32		23	-	-	-	413.1	413.6	(0.5)
15														
16	Total Industrials		103.8	390		32		23		-	-	413.1	413.6	(0.5)
17														
18	Total Core Sales		112,325.9	342,304		843,583		138,968		207	3,458	484,766.0	484,832.9	(66.9)
19														
20	Transportation Service													
21	Schedule 22 - Firm Service	0.091	7,136.8	649	4,783.000	13		746	12.617	256	3,227	4,622.9	5,310.7	(687.8)
22	- Interruptible Service	0.816	11,830.5	9,650	3,742.000	22		988	1.844	15	27	10,664.2	10,506.3	157.9
23	Schedule 23 - Large Commercial	2.397	6,177.2	14,807	210.520	1,318		3,331	-	-	-	18,137.4	18,098.4	39.0
24	Schedule 25 - Firm Service	0.668	12,408.9	8,289	665.000	579		4,620	16.708	813	13,578	26,488.0	25,913.8	574.2
25	Schedule 27 - Interruptible Service	1.111	5,171.9	5,746	958.000	99		1,138	-	-	-	6,884.1	6,828.7	55.4
26														
27	Total T-Service		42,725.3	39,141		2,031		10,823		1,083	16,832	66,796.6	66,657.9	138.7
28														
29	Total Non-Bypass Sales & Transportation Service		155,051.2	381,444.7		845,614		149,790.9		1,290	20,290.0	551,562.6	551,490.8	71.8
30			(X-Ref - Tab C-13, Schedule 15)			(X-Ref - Tab C-13, Schedule 24)					(X-Ref - Tab C-13, Schedule 24 Columns 6 + 8, line 27)			

EARNINGS SHARING CALCULATION - 2009
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Description	2009	Reference
	(1)	(2)	(3)
1	Utility rate base	$2,453,485	- Tab C-13, Schedule 74
2			
3	Common Equity Component (35.01%)	858,965	- Tab C-13, Schedule 75
4			
5			
6	Achieved ROE on Common Equity	11.41%	- Tab C-13, Schedule 75
7			
8	Authorized ROE on Common Equity	8.47%	
9			
10	ROE Surplus / (Deficit)	2.94%	
11			
12	After Tax Surplus Available for Sharing	$25,254	
13			
14			
15	Customers' 50% Share of Surplus (net-of-tax)	$12,627	(X-Ref - Tab C-13, Schedule 70)
16			
17			
18	**Customers' 50% Share of Surplus (pre-tax)**	**$18,038**	(X-Ref - Tab C-13, Schedule 70)

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Tab 13
Schedule 69

END-OF-TERM CAPITAL INCENTIVE MECHANISM
FOR THE YEARS ENDING DECEMBER 31, 2004 TO 2011
($000s)

Line. No.	Particulars	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Projection 2009	2010	2011	2012	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	a) Formula Base Capital Expenditure Spending (with Actual Customer adds)										
2	Customer Addition Driven CapEx	$24,283	$26,319	$21,896	$21,441	$20,133	$13,420				
3	Other Base Capital CapEx	67,361	69,090	70,588	72,278	73,595	74,850				
4	Total Base Capital Expenditures - Formula	91,644	95,409	92,484	93,719	93,728	88,270				
5											
6	b) Actual Base Capital Expenditures										
7	Customer Addition Driven CapEx	$21,896	$25,194	$28,820	$28,903	$32,288	$25,428				
8	Other Base Capital CapEx	48,717	50,840	55,269	44,417	57,859	63,360				
9	Total Base Capital Expenditures - Actual	70,613	76,034	84,089	73,320	90,147	88,788				
10											
11	c) Capital Incentive	$21,031	$19,375	$8,395	$20,399	$3,581	($518)				
12	Cumulative Capital Incentive for Phase-Out	$21,031	$40,406	$48,801	$69,200	$72,781	$72,263				
13											
14	d) Capital Incentive @ 14%	$2,944	$5,657	$6,832	$9,688	$10,189	$10,117				
15											
16	Customer Portion (50/50 during term. Total benefit less Phase-Out after)	$1,472	$2,828	$3,416	$4,844	$5,095	$5,058	$6,745	$8,431	$10,117	
17											
18	Company Portion (50/50 during term. 2/3 & 1/3 Phase-Out in 2010 and 2011)	$1,472	$2,828	$3,416	$4,844	$5,095	$5,058	$3,372	$1,686	$0	
19											
20								(X-Ref - Tab C-13, Schedule 70)			

CALCULATION OF EARNING SHARING MECHANISM (RIDER 3)
FOR THE YEARS ENDING DECEMBER 31, 2010 TO 2011
($000s)

Line No.	Particulars	2010 Volumes (TJ)	2011 Volumes (TJ)	TOTAL Volumes (TJ)	2010 Margin ($000s)	2011 Margin ($000s)	TOTAL Margin ($000s)	2010 True-up & Re: Amortization ($000s)	2010 & 2011 ESM Amortization ($000s)	2010 & 2011 Capital Incentive Amortization ($000s)	2010 ESM Unit Rider ($/GJ)	2011 ESM Unit Rider ($/GJ)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	**Earnings Sharing Mechanism (ESM) Rider 3 Calculation**											
2												
3												
4	**Non-Bypass**											
5	Rate 1 - Residential	67,829.2	67,190.5	135,019.7	$ 306,966	$ 305,757	$612,724	($304)	($7,715)	$2,232	($0.040)	($0.046)
6	Rate 2 - Small Commercial	24,374.3	24,603.1	48,977.4	82,200	82,972	165,171	(83)	(2,081)	599	($0.029)	($0.034)
7	Rate 3 / 23 - Large Commercial	22,952.6	23,345.7	46,298.3	60,218	61,243	121,461	(60)	(1,529)	441	($0.023)	($0.027)
8	Rate 4 - Seasonal Service	184.6	184.6	369.2	248	248	496	-	(6)	2	($0.011)	($0.011)
9	Rate 5 / 25 - General Firm Service	15,565.0	15,470.1	31,035.1	30,469	30,413	60,882	(30)	(767)	222	($0.017)	($0.020)
10	Rate 6 - NGV	103.8	103.8	207.6	377	377	753	-	(9)	3	($0.024)	($0.033)
11	Rate 7 / 27 - Interruptible	5,197.7	5,186.1	10,383.8	6,258	6,247	12,505	(6)	(157)	45	($0.010)	($0.012)
12	Rate 22 - Large Industrial Transportation	11,579.4	11,560.2	23,139.6	9,332	9,318	18,651	(9)	(235)	68	($0.007)	($0.008)
13	Rate 22A - Inland	4,904.7	4,904.7	9,809.4	3,920	3,920	7,841	(4)	(99)	29	($0.007)	($0.008)
14	Rate 22B - Elkview Coal	646.1	646.1	1,292.2	112	112	224	-	(3)	1	$0.000	($0.002)
15	Rate 22B - All Other	1,856.3	1,856.3	3,712.6	1,037	1,037	2,075	(1)	(26)	8	($0.005)	($0.005)
16												
17	**Total Non-Bypass**	155,193.7	155,051.2	310,244.9	$501,138	$501,645	$1,002,783	($497)	($12,627)	$3,650 (1)		
18		(X-Ref - Tab C-13, Schedule 22;		- Tab C-13, Schedule 24)								

19

20 Note 1:
21 Terasen Gas is projecting a 2009 return on equity of 11.41%, which is 2.94% higher than
22 the allowed ROE of 8.47%. Under the earnings sharing mechanism, Terasen Gas is to share
23 equally with its customers, earnings variances between the authorized level of earnings as
24 determined annually under the settlement and the actual earnings of the utility. Accordingly,
25 customer's portion of the 2009 earnings surplus is $18.038 million. The detailed calculations
26 for 2009 are as follows:
27
28 After Tax surplus available for sharing = $858.965 million x (11.41% - 8.47%) = $25,254 million
29 Customers' 50% share (Net-of-Tax) = $12.627 million
30 Customers' 50% share (Pre-Tax) = $18.038 million

Line		Amortization Period	2010 Pre-Tax	2010 Net-Of-Tax	2011 Pre-Tax	2011 Net-Of-Tax	Total Pre-Tax	Total Net-Of-Tax	
32	The total amortization balance of $13.690 is made up of:								
33	2008 true-up ($12.029m per '07 A/Review, $12.739m per '08 A/Rpt)	2011	$710	$508	$0	$0	$710	$508	
34	Tax Adjustment on 2008 ESM True Up		(15)	(11)			(15)	(11)	
35			695	497	-	-	695	497	(Column 8, Line 17)
36									
37	2009 pre-tax Customers' 50% share	2010 and 2011	9,036	6,461	9,003	6,617	18,039	13,078	
38	Tax Adjustment on 2009 ESM		(190)	(136)	(429)	(315)	(618)	(451)	(Column 9, Line 17)
39			8,846	6,325	8,574	6,302	17,420	12,627	(X-Ref - Tab C-13, Schedule 68)
40									
41	2009 End Of Term Capital Incentive Mechanism	2010 and 2011	(3,372)	(2,411)	(1,686)	(1,239)	(5,058)	(3,650)	(Column 10, Line 17)
42									(X-Ref - Tab C-13, Schedule 69)
43	Total Balance - Refund to Customers in 2010 and 2011		$6,169	$4,411	$6,888	$5,063	$13,057	$9,474	(X-Ref - Tab C-13, Schedule 54; Schedule 55 line 39, columns 8 & 9)

CALCULATION OF AMORTIZATION OF RSAM (RIDER 5)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2010 Volumes (TJ)	2011 Volumes (TJ)	2010 Amortization ($000s)	2011 Amortization ($000s)	2010 Amortization of RSAM Unit Rider ($/GJ)	2011 Amortization of RSAM Unit Rider ($/GJ)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**RSAM (Rider 5) Calculation**						
2							
3	Rate 1 - Residential	67,829.2	67,190.5			($0.053)	($0.052)
4	Rate 2 - Small Commercial	24,374.3	24,603.1			($0.053)	($0.052)
5	Rate 3 - Large Commercial	16,818.6	17,168.5			($0.053)	($0.052)
6	Rate 23 - Large Commercial Transportation	6,134.0	6,177.2			($0.053)	($0.052)
7		115,156.1	115,139.3	($6,156)	($5,990) [1]		
8			(X-Ref - Tab C-13, Schedule 54; - Tab C-13, Schedule 55,sum of lines 6 & 7 and columns 8 & 9)				

Note 1: RSAM Rider Change

Terasen Gas forecasts that there will be approximately -$5.6 million (net-of-tax) of RSAM additions by the end of 2009. After offsetting the 2009 RSAM Rider recovery, the RSAM account including interest is now projected to be a credit balance of $13,204,000 on a net-of-tax basis by the end of 2009. In accordance with the 2004-2009 Extended PBR Settlement, the RSAM balance is to be amortized over three years. Accordingly, the net-of-tax RSAM balance to be amortized in 2010 is a credit of $4,402,000. On a pre-tax basis, this amounts to $6,156,000 or a refund to the customer of $0.053/GJ, which is a $.054 reduction from the existing charge of $0.001/GJ. The corresponding 2011 refund to the customer is $0.052/GJ.

2010 Net-Of-Tax Amortization = 1/3 of Projected December 31, 2009 RSAM Balance
= 1/3 * ($-13,166 RSAM + $-38 RSAM Interest)
= 1/3 * $-13,204
= $-4,402 Net-of-tax amortization

2010 Pre-Tax Amortization = Net-of-tax amortization / (1 - tax rate) + Amortization on Prior years' balances
= $-4,402 / (1 - 28.5%)
= $-6,156

2011 Net-of-Tax Amortization = 1/2 of Projected December 31, 2010 RSAM Balance
= 1/2 * ($-8,777 RSAM + $-29 RSAM Interest)
= 1/2 * $-8,806
= $-4,402 Net-of-tax amortization

2011 Pre-Tax Amortization = Net-of-tax amortization / (1 - tax rate) + Amortization on Prior years' balances
= $-4,402 / (1 - 26.5%)
= $-5,990

TERASEN GAS INC.

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Section C
Tab 13
Schedule 72

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Existing 2009 Rates	2009 ----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	108,575	115,723	-	115,723	7,148	
3	Transportation	85,478	89,214	-	89,214	3,736	
4		194,053	204,937	-	204,937	10,884	
5							
6	Average Rate per GJ						
7	Sales	$14.892	$11.902	$0.000	$11.902	($2.990)	
8	Transportation	$0.848	$0.830	$0.000	$0.830	($0.018)	
9	Average	$8.706	$7.000	$0.000	$7.000	($1.706)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,591,039	$1,377,376	$0	$1,377,376	($213,663)	
13	- Increase / (Decrease)	25,852	-	-	-	(25,852)	
14	RSAM Revenue		(17,004)	-	(17,004)	(17,004)	
15	Transportation - Existing Rates	68,993	74,087	-	74,087	5,094	
16	- Increase / (Decrease)	3,535		-	-	(3,535)	
17	**Total**	1,689,419	1,434,459	-	1,434,459	(254,960)	
18							
19	Cost of Gas Sold (Including Gas Lost)	1,187,999	931,546	-	931,546	(256,453)	
20							
21	**Gross Margin**	501,420	502,913	-	502,913	1,493	
22							
23	Operation and Maintenance	173,138	165,162	-	165,162	(7,976)	- Tab C-13, Schedule 28
24	Vehicle Lease	1,804	1,804	-	1,804	-	- Tab C-13, Schedule 28
25	Property and Sundry Taxes	47,593	47,593	-	47,593	-	- Tab C-13, Schedule 31
26	Depreciation and Amortization	89,685	79,725	-	79,725	(9,960)	- Tab C-13, Schedule 33
27	Other Operating Revenue	(23,444)	(20,906)	-	(20,906)	2,538	- Tab C-13, Schedule 26
28		288,776	273,378	-	273,378	(15,398)	
29	Utility Income Before Income Taxes	212,644	229,535	(1)	229,535	16,891	
30							
31	Income Taxes	26,331	23,010	1	23,010	(3,321)	
32							
33	**EARNED RETURN**	$186,313	$206,525	$0	$206,525	$20,212	(X-Ref - Tab C-13, Schedule 73)
34							
35							
36	**UTILITY RATE BASE**	$2,541,358	$2,453,485	$0	$2,453,485	($87,873)	- Tab C-13, Schedule 74
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.33%	8.42%		8.42%	1.09%	

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Existing 2009 Rates	----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$186,313	$206,525	$0	$206,525	$20,212	- Tab C-13, Schedule 72
3	Deduct - Interest on Debt	(110,953)	(108,525)	-	(108,525)	2,428	- Tab C-13, Schedule 75
4	Add- Non-Tax Ded. Expense (Net)	328	428	-	428	100	
5							
6	Accounting Income After Tax	75,688	98,428	-	98,428	22,740	
7	Add (Deduct) - Timing Differences	(14,248)	(44,736)	-	(44,736)	(30,488)	- Tab C-13, Schedule 37
8							
9	Taxable Income After Tax	$61,440	$53,692	$0	$53,692	($7,748)	
10							
11		30.000%	30.000%	30.000%	30.000%	0.000%	
12	1 - Current Income Tax Rate	70.000%	70.000%	70.000%	70.000%	0.000%	
13							
14	Taxable Income	$87,771	$76,703	$0	$76,703	($11,068)	
15							
16	**Total Income Tax**	$26,331	$23,011	$0	$23,011	($3,320)	
17							

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Existing 2009 Rates	2009 Adjustments	2009 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,339,098	$3,215,664	$0	$3,215,664	($123,434)	
2	Adjustment - CPCNs	12,855	12,879	-	12,879	24	
3	Gas Plant in Service, Ending	3,442,274	3,317,590	-	3,317,590	(124,684)	- Tab C-13, Schedule 45
4							
5	Accumulated Depreciation Beginning - Plant	($808,588)	($743,486)	$0	($743,486)	$65,102	
6	Accumulated Depreciation Ending - Plant	(869,177)	(779,187)	-	(779,187)	89,990	- Tab C-13, Schedule 49
7							
8	CIAC, Beginning	($148,423)	($161,636)	$0	($161,636)	($13,213)	
9	CIAC, Ending	(146,828)	(176,845)	-	(176,845)	(30,017)	- Tab C-13, Schedule 52
10							
11	Accumulated Amortization Beginning - CIAC	$46,175	$45,381	$0	$45,381	($794)	
12	Accumulated Amortization Ending - CIAC	44,846	44,146	-	44,146	(700)	- Tab C-13, Schedule 52
13							
14	Net Plant in Service, Mid-Year	$2,456,116	$2,387,253	$0	$2,387,253	($68,863)	
15							
16							
17	Adjustment to 13-Month Average	-	(10,554)	-	(10,554)	(10,554)	
18	Work in Progress, No AFUDC	15,773	15,627	-	15,627	(146)	
19	Unamortized Deferred Charges*	(32,644)	(25,545)	-	(25,545)	7,100	- Tab C-13, Schedule 76
20	Cash Working Capital	(33,719)	(27,183)	-	(27,183)	6,536	- Tab C-13, Schedule 56
21	Other Working Capital (incl. Construction Advances)	138,198	115,701	-	115,701	(22,497)	- Tab C-13, Schedule 56
22	Future Income Taxes Regulatory Asset	-	278,048	-	278,048	278,048	- Tab C-13, Schedule 61
23	Future Income Taxes Regulatory Liability	(552)	(278,048)	-	(278,048)	(277,496)	- Tab C-13, Schedule 61
24	LILO Benefit	(1,814)	(1,814)	-	(1,814)	-	
25	**Utility Rate Base**	$2,541,358	$2,453,485	$0	$2,453,485	($87,873)	(X-Ref - Tab C-13, Schedule 68, Schedule 72,Schedule 75)

*Not equal to Schedule 8, column (2), line 19 because of differences in MCRA, CCRA and ESM balances for ESM calculation purposes

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Reference	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2009 RATES							
2	Long-Term Debt			$1,504,299	62.36%	6.959%	4.34%	
3	Unfunded Debt			90,221	2.63%	4.250%	0.11%	
4	Preference Shares			-	0.00%	0.000%	0.00%	
5	Common Equity			858,965	35.01%	11.740%	4.11%	
6								
7		- Tab C-13, Schedule 74		$2,453,485	100.00%		8.56%	
8								
9	2009 REVISED RATES							
10	Long-Term Debt			$1,504,299	61.31%	6.959%	4.27%	$104,691
11	Unfunded Debt		$90,221					
12	Adjustment, Revised Rates		-	90,221	3.68%	4.250%	0.16%	3,834
13	Preference Shares			-	0.00%	0.000%	0.00%	-
14	Common Equity			858,965	35.01%	11.409%	3.99%	97,999
15		(X-Ref - Tab C-13, Schedule 72)						
16		- Tab C-13, Schedule 74		$2,453,485	100.00%		8.42%	$206,525

TERASEN GAS INC. June 12, 2009 Advance Materials Section C

Tab 13

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION Schedule 76

FOR THE YEAR ENDING DECEMBER 31, 2009

($000s)

Line No.	Particulars	Balance 12/31/2008	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2009	Mid-Year Average 2009
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Margin Related									
2	Commodity Cost Reconciliation Account (CCRA)	($23,164.7)	$602.9	($180.9)	$422.0	$0.0	$0.0	$0.0	($22,742.7)	($22,953.7)
3	CCRA Interest	(596.2)	(428.2)	128.5	(299.7)	-	-	-	(895.9)	(746.1)
4	Midstream Cost Reconciliation Account (MCRA)	(23,588.7)	85,731.4	(25,719.4)	60,012.0	-	-	-	36,423.3	6,417.3
5	MCRA Interest	(1,812.2)	47.2	(14.2)	33.0	-	-	-	(1,779.2)	(1,795.7)
6	Revenue Stabilization Adjustment Mechanism (RSAM)	(7,917.2)	(7,902.9)	2,370.9	(5,532.0)	-	405.1	(121.5)	(13,165.6)	(10,541.4)
7	RSAM Interest	35.3	(133.2)	40.0	(93.2)	-	27.8	(8.3)	(38.4)	(1.6)
8	Revelstoke Propane Cost Deferral Account	(477.8)	627.1	(188.1)	439.0	-	-	-	(38.8)	(258.3)
9	SCP Mitigation Revenues Variance Account	(4,539.0)	(981.7)	324.5	(657.2)	1,078.1	-	-	(4,118.1)	(4,328.6)
10	SCP West to East Transmission	(1,658.0)	(376.1)	124.7	(251.4)	371.2	-	-	(1,538.2)	(1,598.1)
11										
12	Energy Policy Related									
13	Energy Efficiency & Conservation (EEC)	1,205.0	8,002.0	(2,400.6)	5,601.4	(436.2)	-	-	6,370.2	3,787.6
14	NGV Conversion Grants	124.0	80.0	(24.0)	56.0	(43.1)	-	-	136.9	130.5
15										
16	Non-Controllable Items									
17	Property Tax Deferral	(732.0)	(700.0)	210.0	(490.0)	478.2	-	-	(743.8)	(737.9)
18	Insurance Variance	(259.0)	(479.5)	143.9	(335.6)	(91.4)	-	-	(686.0)	(472.5)
19	Pension & OPEB Variance	207.0	(581.4)	-	(581.4)	(312.0)	-	-	(686.4)	(239.7)
20	BCUC Levies Variance	(295.0)	(383.7)	115.1	(268.6)	301.6	-	-	(262.0)	(278.5)
21	Interest Variance	(1,629.0)	(790.1)	237.0	(553.1)	(50.1)	-	-	(2,232.2)	(1,930.6)
22	Interest Variance - Funding benefits via Customer Deposits	161.0	76.9	(23.1)	53.8	(0.6)	-	-	214.2	187.6
24	Olympics Security Costs Deferral	-	746.9	(224.1)	522.8	-	-	-	522.8	261.4
25	IFRS Conversion Costs	98.0	430.7	(129.2)	301.5	-	-	-	399.5	248.8
26										
27	Cost of Current Applications									
28	2009 ROE & Cost of Capital Application	$0.0	$630.0	($189.0)	$441.0	$0.0	$0.0	$0.0	$441.0	$220.5
29	2010-2011 Revenue Requirement Application	55.0	1,057.5	(317.3)	740.2	-	-	-	795.2	425.1
30	CCE CPCN Application	-	270.0	(81.0)	189.0	-	-	-	189.0	94.5
31										-
32	Other									-
33	IFRS Transitional Adjustments	-	-	-	-	-	-	-	-	-
34	OPEB Funding	(28,644.0)	(5,582.6)	1,674.8	(3,907.8)	-	-	-	(32,551.8)	(30,597.9)
35	Pension & OPEB Funding	-	-	-	-	-	-	-	-	-
36										-
37	Residual Deferred Charges									-
38	SCP Tax Reassessment	7,292.8	165.0	(49.5)	115.5	-	-	-	7,408.3	7,350.6
39	Deferred Service Line Installation Fee	-	1,442.9	-	1,442.9	-	-	-	1,442.9	1,442.9
40	Earnings Sharing Mechanism	(9,879.1)	(18,748.0)	5,624.4	(13,123.6)	-	14,113.0	(4,233.9)	(13,123.6)	(11,501.4)
41	CCT Assessment	(16.0)	-	-	-	13.5	-	-	(2.5)	(9.3)
42	Carbon Tax Implementation	103.0	-	-	-	(198.0)	-	-	(95.0)	4.0
43	TGS Amalgamation	132.0	-	-	-	-	-	-	132.0	132.0
44	TGS O&M Variance	233.0	170.0	(51.0)	119.0	-	-	-	352.0	292.5
45	Carbon Tax Cost of Service	(384.0)	326.0	(97.8)	228.2	111.8	-	-	(44.0)	(214.0)
46	OSC Certification Compliance	90.0	110.7	(33.2)	77.5	(76.4)	-	-	91.1	90.6
47	Bad Debt Allowance for Rates 14 & 14A	(114.0)	(26.6)	0.4	(26.2)	-	-	-	(140.2)	(127.1)
53										
54	Total Deferred Charges for Rate Base	($94,895.0)	$63,403.2	($18,728.2)	$44,675.0	$71.8	$14,545.9	($4,363.7)	($39,966.0)	($66,709.1)
55										
56				Reconciliation with Mid Year Deferred Charges for ESM calculation:						
57										
58				Less:	Projected Mid Year MCRA balance (+ interest)				4,621.6	
59					Projected Mid Year CCRA balance (+ interest)				(23,699.8)	
60					Projected Mid Year Revelstoke Propane balance				(258.3)	
61					Projected Mid Year ESM balance				(11,501.4)	
62					Projected Mid Year RSAM balance (+ interest)				(10,543.0)	(41,380.9)
63										
64				Add:	Approved Mid Year MCRA balance (+ interest)				7,961.3	
65					Approved Mid Year CCRA balance (+ interest)				(12,224.5)	
66					Approved Mid Year Revelstoke Propane balance				16.7	
67					Approved Mid Year Approved balance				3,916.2	
68					Approved Mid Year RSAM balance (+ interest)				113.7	(216.6)
69										
70					Mid Year Deferred Charges balance for ESM purposes					($25,544.8)
71										(X-Ref - Tab C-13, Schedule 74)

D. Approvals Sought and Proposed Regulatory Process

In this section TGI identifies the approvals sought in this Application. TGI also proposes a regulatory process that it regards as permitting the efficient consideration of this Application.

1. Approvals Sought

The requirement for a rate increase in 2010 and 2011 is determined by various business drivers, most notably accounting changes, but including projected customer use rates, volumes and revenues, capital expenditures and operating and maintenance expenses. TGI needs to invest in its business in 2010 and 2011 to permit TGI to continue to provide safe, reliable, and cost effective service and meet the evolving needs of its customers and the communities it serves. Detailed support material has been provided in Part III which shows the impact of these business drivers on the TGI revenue requirements for 2010 and 2011.

TGI respectfully seeks the following orders from the Commission:

1. An order pursuant to sections 59 to 61 of the Act approving permanent delivery rates for all non-bypass customers effective January 1, 2010 and January 1, 2011, to recover the requested revenue requirements as described in Part III, Section C, Tab 2 of the Application, subject to changes in TGI's allowed return on equity and capital structure as described in Part III, Section C, Tab 10 of the Application. As set out in Part III, Section C, Tab 13 Schedules 1, 2 and 3, compared to 2009 rates, the permanent rates requested in this Application reflect delivery rate increases of:
    a) 5.3 per cent for 2010, based on an increased revenue requirement of $27.9 million; and
    b) 4.1 per cent for 2011, based on a further increased revenue requirement of $21.9 million.

    The rate increases will be to the volumetric and demand-based delivery rates, with the basic charge and administration fees held at existing approved 2009 levels, as described in Part III, Section C, Tab 2 of the Application.

2. An order pursuant to section 89 of the Act for interim rates for all non-bypass customers as proposed in this Application for 2010 effective January 1, 2010. Any refund or under-collection following the granting of interim rates will be addressed by way of a rate rider to refund or collect from customers the variance in interim rates versus permanent rates approved.

3. An order approving the Earnings Sharing Mechanism rider for customers served under Rate Schedules 1, 1U, 1X, 2, 2U, 2X, 3, 3U, 3X, 4, 5, 6, 7, 22, 22A, 22B, 23, 25 and 27 effective January 1, 2010 and effective January 1, 2011, as set out in Part III, Section C, Tab 13, Schedule 70.

4. An order approving the Rate Stabilization Adjustment Mechanism rider for customers served under Rate Schedules 1, 1S, 1X, 2, 2U, 2X, 3, 3U,3X and 23 effective January 1, 2010 of ($0.053)/GJ and effective January 1, 2011 of ($0.052)/GJ, as set out in Part III, Section C, Tab 13, Schedule 71.

5. An order pursuant to section 44.2 of the Act approving the additional EEC expenditures set out in Part III, Section C, Tab 3 – Table C-3-2 of the Application, namely:
   a) EEC expenditures for interruptible industrial programs and innovative technologies totaling $2.8 million for 2010 and $6.5 million for 2011; and
   b) EEC funding for 2011 in the amount of $23.1 million for all EEC programs areas approved by the Commission for 2008-2010 in the EEC Application Decision dated April 16, 2009, with the re-allocation of a portion of this funding to programs aimed at low income customers and rental housing as described in Part III, Section C, Tab 3 of the Application.

6. An order that all proposed EEC expenditures outlined in this Application be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Application Decision dated April 16, 2009.

7. An order approving modifications to:
   a) The pricing methodology for company use gas from using expired 'netback' contracts pricing to using market-based Sumas pricing as set out in Part III, Section C, Tab 5 of the Application.
   b) The current methodology of accounting for volumes variances related to company use gas, so that O&M costs will no longer be adjusted for the actual volumes consumed. The new methodology will use the Midstream Cost Reconciliation Account (MCRA) to absorb any volumes not used or excess volumes required for company use gas going forward as set out in Part III, Section C, Tab 5 of the Application.
   c) Inclusion of SCP capacity in the MCRA, extension of the continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year by a period of ten years from November 1, 2010 until November 1, 2020, and an increase in the SCP Net Mitigation Revenue included in the determination of delivery rates from $1 million to $2.4 million, all as set out in Part III, Section C, Tab 4 under "Other Revenue" of the Application.

8. An order approving:
    a) The allocation of costs for shared Corporate Services between Terasen and Terasen Gas for the years 2010 and 2011, as reflected in the Corporate Services Agreement between Terasen and TGI as described in Part III, Section C, Tab 11 of the Application;
    b) The allocation of costs for Shared Services between TGI and TGVI, and TGI and TGW, for the years 2010 and 2011, as reflected in the Shared Services Agreement between TGI and TVGI and Shared Services Agreement between TGI and TGW as described in Part III, Section C, Tab 11 of the Application;
    c) Adoption of the cash working capital lead lag days as set out in the Lead Lag Study discussed in Part III, Section C, Tab 11 of the Application; and
    d) Consolidated Core Market Administration Expense (for Terasen Gas, TGVI and TGW), and allocation percentages, as set out in Part III, Section C, Tab 5 of the Application.

9. An order establishing the threshold for new capital projects requiring a CPCN at $20 million as set out in Part III, Section C, Tab 9 of the Application;

10. An order approving deferral accounts, and the amortization and disposition of balances, as set out in Part III, Section C, Tab 8 of the Application;

11. Changes to accounting policies to be used in the determination of rates effective January 1, 2010, all as set out in Part III, Section C, Tab 8 and Part III, Section C, Tab 11 of the Application:
    - O&M treatment for training costs and feasibility study costs;
    - Capitalization of major inspection costs, including the creation of a new asset class;
    - Capitalization of the current service portion of pension and other post employment benefit expense that is applicable to capital projects;
    - Capitalization of depreciation on assets used in construction;
    - Capital expenditures to be included in plant in service in the month following the available-for-use date, including CPCN additions, with depreciation starting at that time;
    - New depreciation rates, changing the composite average rate from 2.7 per cent to 3.4 per cent;
    - New overheads capitalized rate, changing the rate from 16 per cent of adjusted gross O&M expense to 8 per cent of gross O&M expense;
    - Treatment of the vehicle lease as a capital lease and inclusion of the net book value of vehicles in rate base; and

- Discontinuation of the software tax credit mechanism as part of the contribution in aid of construction additions.

12. An order pursuant to sections 59 to 61 of the Act approving Tariff changes effective January 1, 2010, as set out in Part III, Section C, Tab 12 of the Application, including:

    - New Tariff offerings:

        i. Compression and Refueling Service for NGV Market – Rate Schedule 6C as set out in Part III, Section C, Tab 12 and Appendix J-6. of the Application;
        ii. NGV Transportation Service – Rate Schedule 26 as set out Part III, Section C, Tab 12 and Appendix J-4 of the Application;
        iii. Close Rate Schedule 6A if (i) and (ii) above are approved as set out in Part III, Section C, Tab 12 and Appendix J-5 of the Application;
        iv. Economic models for evaluating alternative energy extensions for geo-exchange, solar thermal and district energy systems, and establishing the regulatory review processes, as set out in Part III, Section C, Tab 3 of the Application; and
        v. New terms and conditions in GT&C, Section 12A – Alternative Energy Extensions as set out in Part III, Section C, Tab 12 and Appendix J-3 of the Application.

    - Revised fee structure as set out in Part III, Section C, Tab 12 and Appendix J-2 of the Application:

        i. Revise the new customer application fee from $85 to $25; and
        ii. Revise the meter testing fee from $30 to $60.

13. An order approving the proposed test for evaluating biogas upgrading projects in the Pilot Phase, and establishing the regulatory review process as set out in Part III, Section C, Tab 3 of the Application.

The relief sought in this Application does not have the potential to adversely affect aboriginal rights and title. As such, no duty to consult First Nations arises in respect of this Application.

2. Proposed Regulatory Process

Terasen Gas proposes a timetable that considers the proposed timing of all of the significant applications filed or being filed by the Terasen Utilities in 2009. The timetable acknowledges the corresponding workload required by the Commission and all parties. The proposed regulatory timetable will promote an efficient regulatory process.

TGI believes that this Application can be addressed efficiently and effectively through a written hearing process. There are three main reasons why this is the case.

1. The major contributors to the forecast revenue deficiency in 2010 and 2011 are mandatory changes to accounting standards. But for accounting changes associated with the adoption of International Financial Reporting Standards (IFRS), and additional costs related to the introduction of new codes and regulations and changes to government policy, the incremental revenue requirement outlined in this Application of $27.9 million for 2010 and $49.8 million for 2011 would have been a revenue surplus of $17.8 million in 2010 and a deficiency of $1.9 million in 2011. These changes in accounting policies will affect the timing of when costs are recovered and thereby affect the determination of TGI's revenue requirements and rates. Increases in the short-term are expected to be offset by lower rates in the future.

2. The total gross O&M expenses have increased from the level included in the 2009 projection; however, when considered on a per customer basis and after adjusting for inflation, the costs in both 2010 and 2011 are lower than those included in the 2003 Decision, which formed the basis for the PBR Agreement. Customers are obtaining permanent benefits from the efficiency gains obtained through the PBR Period.

3. A significant amount of historical and contextual information has been provided with this Application. The Commission and intervenors will have that information available to them when developing information requests. The value of having that information up front is also to allow all parties to focus on the issues rather than needing to request additional information during the IR process. TGI is also proposing a workshop for shortly after the filing of this Application, which should assist in focusing the discussion. TGI is committed to responding to relevant information requests to the best of its ability.

TGI is optimistic that the Commission will be in a position to make its determination regarding the type of hearing process following the procedural conference proposed for July 9, 2009. We believe that, at a minimum, the scope of any oral hearing should be carefully circumscribed by procedural order. The purpose of such a scoping order would be to limit an oral hearing to the most significant issues or to those issues that are anticipated to require additional process to elicit the evidence. The remaining issues would be efficiently addressed based on the written record. The issues in this Application are sufficiently broad that the alternative to a written or carefully circumscribed hearing could be a lengthy and unfocussed hearing. This adds considerable preparation work for the Commission, the Applicant and other parties, much of which might add little value to a written process.

TGI is open to a negotiated settlement of all of the issues, should the parties believe that is a possibility.

The proposed timetable is:

Action	Date (2009)
File Application	Monday, June 15, 2009
Procedural Order (up to Procedural Conference)	Thursday, June 18, 2009
Workshop	Monday, July 6, 2009
Intervenor Registration	Monday, July 6, 2009
Procedural Conference	Thursday, July 9, 2009
Procedural Order (Timetable and Process)	Wednesday, July 15, 2009
BCUC IR No. 1	Thursday, July 16, 2009
Intervenor IR No. 1	Thursday, July 23, 2009
TGI Response to IRs No. 1	Friday, August 14, 2009
BCUC IR No. 2	Thursday, August 27, 2009
Intervenor IR No. 2	Thursday, August 27, 2009
TGI Response to IRs No. 2	Friday, September 11, 2009
Negotiated Settlement Process or Hearing (proposed date range)	Monday, October 19, 2009 to Friday, October 30, 2009
TGI Final Argument Submissions	Friday, November 13, 2009
Intervenor Final Argument Submissions	Friday, November 27, 2009
TGI Reply Argument Submissions	Monday, December 7, 2009
Anticipated BCUC Decision	Friday, January 15, 2010

Since we are not expecting a Decision in time for permanent rates to be implemented for January 1, 2010, TGI respectfully requests an order pursuant to section 89 of the Act for interim rates for all non-bypass customers as proposed in this Application for 2010 effective January 1, 2010. As indicated in the order sought, any refund or under-collection following the granting of interim rates would be addressed by way of a rate rider to refund or collect from customers the variance between the interim rates and the permanent rates ultimately approved.

TGI looks forward to working with the Commission and Intervenors towards an efficient hearing of this Application.

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GLOSSARY

GLOSSARY OF TERMS

ACESA – American Clean Energy Security Act

ACP – Annual Contracting Plans, which are yearly filings with the Commission providing details on the Company's gas supply and midstream resource procurement activities for the year and discussion of the factors and influences affecting gas supply costs in the short and longer term.

Act – Utilities Commission Act

AFUDC –Allowance for Funds Used During Construction, which is an allowance for the cost of debt and equity funding of capital projects before they are completed and placed into service and included in rate base; the AFUDC recorded for a project is added to the overall project cost.

AKBLG – Association of Kootenay Boundary Local Government

AIT – Agreement on Internal Trade

AM/FM – Automated Mapping/Facilities Management

AMR – Automated Meter Reading

ANSI – American National Standards Institute

APEGBC – Association of Professional Engineers and Geoscientists of BC

API – American Petroleum Institute

ASL – Average Service Life

ASTTBC - Applied Science Technologists and Technicians of British Columbia, or Association for Technology Professionals in British Columbia

AUBPOS – Accenture Utilities BPO Services

AVICC - Association of Vancouver Island and Coastal Communities

B&ITS / BAITS - Business and Information Technology Services (Terasen Gas department)

BC or B.C. – British Columbia

BCBC – Business Council of British Columbia

BC Hydro – British Columbia Hydro and Power Authority

BCIT – British Columbia Institute of Technology

BCSA – British Columbia Safety Authority

BCUC – British Columbia Utilities Commission, the provincial body regulating utilities in British Columbia.

Board – the Board of Directors of Terasen Gas Inc.

BOC – Bank of Canada

BPO – Business Process Outsource

BSI – British Standards Institute

CAFÉ – Customer Attraction Front End project

Capex – Capital expenditures

CAT – Climate Action Team

CCA – Capital Cost Allowance

CCRA – Commodity Cost Reconciliation Account

CEPA - Canadian Energy Pipeline Association

CGA – Canadian Gas Association

CIAC – Contributions in Aid of Construction

CICA – Canadian Institute of Chartered Accountants

CIS - Customer Information System

ClickSchedule – a Distribution field resources work scheduling platform

CMAE - Core Market Administration Expense

CMHC – Canada Mortgage and Housing Corporation

CNG – Compressed Natural Gas

COC – Code of Conduct, which is a policy document approved by the Commission setting out the working relationships between Terasen Gas Inc. and non-regulated affiliates

COG – Cost of Gas

Cogeneration – refers to the simultaneous generation of electricity and useful thermal energy by utilizing the waste heat from a gas turbine to generate steam to be used in another process.

Commission - British Columbia Utilities Commission, the provincial body regulating utilities in British Columbia.

Company – Terasen Gas Inc.

Compression / Compressor Station – the application of increased pressure to a natural gas pipeline system to create gas flow. Higher levels of compression can be applied to increase the carrying and storage capacity of the pipeline. Increased pressure is applied through a compressor station constructed along the pipeline.

Compression Service – Rate Schedule 6C – Natural Gas Compression and Refueling Service, a new tariff service being applied for in this Application

COPE – Canadian Office of Professional Employees

Core / Core Customers / Core Market – residential, commercial and small industrial customers that have gas delivered to their home or business (bundled sales). Terasen Gas purchases natural gas and delivers it to the customer in a bundled sales rate. Core Market customers typically use a significant portion of their gas requirements for heating applications, resulting in weather sensitive demand.

COS – Cost of Service, a term used in utility ratemaking referring to the total costs of providing a service, typically including operating expenses, depreciation expense, taxes and a fair return on investment for the utility. In some cases Cost of Service also includes cost of gas

CP – Cathodic Protection

CPCN – Certificate of Public Convenience and Necessity, a certificate is obtained from the BCUC under Section 45 of the Utilities Commission Act for the construction and, or operation of, a public utility plant or system, or an extension of either, that is required for public convenience and necessity.

CPI – Consumer Price Index

CPR - Conservation Potential Review, a study completed to identify opportunities for energy savings across gas and electrical energy delivery infrastructures and improvements to overall energy utilization efficiency.

CRA – Canada Revenue Agency

CS – Compression Service

CSA – Canadian Standards Association

CWLP – CustomerWorks Limited Partnership

Deferred Costs (or Charges) – operating and maintenance costs that are incurred but that will be expensed in the future.

Demand Forecast – a prediction of the demand for natural gas into the future for a given period and under a specified set of expected future conditions. Separate demand forecasts are developed for annual energy demand and peak day demand and utilized for different aspects of utility operations and planning.

DES – District Energy Systems

DHW – Domestic Hot Water

DLE – Diesel Litre Equivalent,

DP – Distribution Pressure, pipelines operating at pressures of 100 psig or less (700 kPa or less)

DMS – Distribution Mobile Solution

DRP – Disaster Recovery Plan

DSM – Demand-Side Management, defined as "any utility activity that modifies or influences the way in which customers utilize energy services". From Terasen Gas' perspective, the primary objectives of DSM are to increase the overall economic efficiency of the energy services it provides to customers and maintain the competitive position of natural gas relative to other energy sources.

EEC – Energy Efficiency and Conservation.

EH&S – Environment, Health & Safety

ELG – Equal Life Group

ELT – Executive Leadership Team

EMP – Environmental Management Plan

EMS – Energy Management Services

ERM – Enterprise Risk Management

ESM – Earnings Sharing Mechanism

FERC - Federal Energy Regulatory Commission

FTE - Full time equivalent employee

GAAP – Generally Accepted Accounting Principles

GCRA – Gas Cost Reconciliation Account

GDP – Gross Domestic Product

GGRTA - 2007 Greenhouse Gas Reduction Targets Act

GHG – Greenhouse Gas

GHSP – Ground Source Heat Pump

GIS – Geographic Information Systems

GJ – Gigajoule – a measure of energy equivalent to one billion joules. One joule of energy is equivalent to the heat needed to raise the temperature of one gram (g) of water by one degree Celsius (ºC) at standard pressure (101.325 kPa) and standard temperature (15ºC).

GLE- Gasoline Litre Equivalent

GPIS – Gross Plant In-Service

GSMIP – Gas Supply Mitigation Incentive Plan

GST – Goods and Services Tax

GS&T – Gas Supply and Transmission (Terasen Gas department)

GT&C – General Terms and Conditions

GWh – Gigawatt-hours

HR – Human Resources

HROG – Human Resources and Operations Governance (Terasen Gas department)

IAS – Internal Audit Services

IASB – International Accounting Standards Board

IBEW – International Brotherhood of Electrical Workers

ICE Fund – Innovative Clean Energy Fund

ICE Levy – Innovative Clean Energy levy of 0.4% on utility customer bills

IFRS – International Financial Reporting Standards

ILI – In-line inspection

IMP – Integrity Management Plan

IP – Intermediate pressure

IPPs – Independent Power Producers

IRM – Integrated Resource Management

ISO - International Organization for Standardization

IT – Information Technology

ITS – Interior Transmission System

KMI – Kinder Morgan Inc.

LCT – Large Corporations Tax

LDC – Local Distribution Company

LGMA - Local Government Management Association

LILO – Lease In-Lease Out

LMLGA - Lower Mainland Local Government Association

LMS – Learning Management System

LNG - Liquefied natural gas, natural gas stored at a low temperature turns to liquid form. Approximately 600 times as much natural gas can be stored in its liquid state than in its typical gaseous state; however, specialized storage facilities must be constructed.

LP – Low Pressure

LTAP – Long Term Acquisition Plan

M&E – Management and Exempt employees

MCRA – Midstream Cost Reconciliation Account

MFD – Multi Family Dwelling

MFT – Motor Fuel Tax

MIT – Manager-in-Training

MKBD – Marketing and Business Development (Terasen Gas department)

MMcfd – One Million Cubic Feet per Day

Mt – Megatonne

MTN – Medium Term Note

MX – Main Extension

MW - Megawatt

NCMA - Northern Community Municipal Association

NEB – National Energy Board

NGTL – Nova Gas Transmission Limited

NGV – Natural Gas for Vehicles

NPIS – Net Plant in Service

NRB – Non-regulated Business

NWGA – Northwest Gas Association

NWN – Northwest Natural Gas Company

NWP – Northwest Pipeline Corporation

OEM – Other Equipment Manufacture

OGC – British Columbia Oil and Gas Commission

OPEB – Other Post Employment Benefits

O&M – Operating and Maintenance Costs all costs incurred to operate and maintain the completed Customer Care Enhancement Project and that do not result in an improvement of a long-term asset; these costs will be included in regular operating budgets and treated as an operating and maintenance expense.

OSC – Ontario Securities Commission

PMO – Project Management Office (Terasen Gas department)

PBR – Performance Based Rates

PBR Agreement – Terasen Gas' current PBR Agreement approved pursuant Order No. G-51-03 and extended pursuant to Order No. G-33-07

PBR Period – Six year period of Terasen Gas' current PBR Agreement commencing January 1, 2004 ending December 31, 2009

PI – Profitability Index

PJ – Petajoule – equal to 1000 terajoules or 10^6 gigajoules.

PLE – Propane Litre Equivalent

PNG – Pacific Northern Gas

PPE – Property, Plant and Equipment

PST - Provincial Sales Tax in British Columbia

PV – Present Value

QUEST - Quality Urban Energy Systems of Tomorrow

Rate Volatility – the magnitude and frequency of natural gas rate fluctuations

RDA – Rate Design Application

REUS – Residential End Use Survey

RFEOI – Request for Expressions of Interest

RIB – Residential Inclining Block

RMDM – Retail Markets Downstream of the Meter

ROE – Return on Equity

ROW – Right of Way

RRA – Revenue Requirements Application

RRSP – Registered Retirement Savings Plan

RSAM - Revenue Stabilization Adjustment Mechanism

SCADA - Supervisory Control and Data Acquisition

SCC – Stress Corrosion Cracking

SCP – Southern Crossing Pipeline

SDE – Service Delivery Enhancement Project

SERP – Supplemental Executive Retirement Plan

SFU – Simon Fraser University

SILGA - Southern Interior Local Government Association

SLCA – Service Line Cost Allowance

SQI – Service Quality Indicator

SST – Social Services Tax

TCPL – TransCanada Pipelines Limited

TEEC – Technology Education and Career Council

Terasen – Terasen Inc.

Terasen Utilities - Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc.

TES – Terasen Energy Services Inc.

TGI – Terasen Gas Inc., a subsidiary of Terasen Inc.

TGS – Terasen Gas (Squamish) Inc., amalgamated with Terasen Gas effective January 1, 2007

TGVI - Terasen Gas (Vancouver Island) Inc., a subsidiary of Terasen Inc.

TGW - Terasen Gas (Whistler) Inc., a subsidiary of Terasen Inc.

TILMA - Trade, Investment and Labour Mobility Agreement

TJ – Terajoule – equal to 1000 gigajoules.

TPIP - Transmission Pipeline Integrity Program

TPP – Transfer Pricing Policy

UAF – Unaccounted-for Gas

UBC – University of British Columbia

UBCM - Union of British Columbia Municipalities

UCC – Undepreciated Capital Cost

UFV – University of the Fraser Valley

UOC – Utilities Operating Committee

USP - Utilities Strategy Project

WACC – Weighted Average Cost of Capital

WCI – Western Climate Initiative

WEI – Western Energy Institute

WIP – Work in Progress

WMS/PM – Work Management System/Preventive Maintenance

WWTP – Waste Water Treatment Plant

Appendix B

HISTORIC COMPANY AND REGULATORY INFORMATION

Corporate History

Terasen Gas Inc. is a company incorporated under the laws of the Province of British Columbia with over 50 years of history in the natural gas business with a proven record for offering a reliable supply of natural gas, delivered safely and efficiently at a reasonable cost.

The company began distribution and transmission of natural gas in BC in the 1950's. In 1952, Inland Natural Gas Co. Ltd. ("Inland") was incorporated to distribute natural gas throughout the BC interior. In the 1950's, Inland purchased several subsidiaries, including St. John Oil and Gas, Peace River Transmission, Canadian Northern Oil and Gas, and Grand Prairie Transmission. In 1977, Inland purchased Columbia Natural Gas in the East Kootenays, which positioned Inland as the major distributor of natural gas for most of the BC Interior. In 1985 Inland acquired Fort Nelson Gas Ltd., the owner of the gas distribution system in and around Fort Nelson, from Colonial Oil and Gas Limited and in 1987, Inland purchased Squamish Gas Co. Ltd. from Superior Propane Ltd. In 1988, through a holding company named B.C. Gas Inc., Inland purchased the Lower Mainland gas division of BC Hydro. In 1989, Inland was amalgamated with B.C. Gas Inc., Columbia Natural Gas Limited, and Fort Nelson Gas Ltd. under the name BC Gas Inc. and become the fourth largest gas distribution utility in Canada.

In 1993 restructuring caused BC Gas Inc. to change its name to BC Gas Utility Ltd. and a holding company that held all the shares of BC Gas Utility Ltd. was named BC Gas Inc. A subsidiary of BC Gas Utility Ltd. was Squamish Gas Co. Ltd. BC Gas Inc. purchased Centra Gas BC Inc. and Centra Gas Whistler Inc in 2002, adding natural gas customers on the Sunshine Coast and Vancouver Island and piped propane customers in Whistler. In 2003, BC Gas Inc. changed the name of each of its corporate entities, with BC Gas Inc. becoming Terasen Inc. and BC Gas Utility Ltd. becoming Terasen Gas Inc. In 2005, Terasen Inc. was acquired by Kinder Morgan Inc., a U.S. energy storage and transportation company operating on behalf of Kinder Morgan Energy Partners, L.P. In 2007, Terasen Gas Inc. and Terasen Gas (Squamish) Inc. were amalgamated to operate as one company under the name, Terasen Gas Inc. In 2007, Fortis Inc. acquired Terasen Inc. from Kinder Morgan Inc. and so Terasen Inc. is now an indirect wholly-owned subsidiary of Fortis Inc., the largest distribution utility in Canada.

Today, TGI, a wholly owned subsidiary of Terasen Inc., is the largest natural gas distribution utility in BC, providing sales and transportation services to residential, commercial, and industrial customers in more than 100 communities throughout the Province, with 834,211 customers served on the mainland including the Inland, Columbia, Fort Nelson, and Lower Mainland service areas. This includes the municipality of Revelstoke where TGI operates a propane distribution system serving approximately 1,600 customers. TGI owns and operates natural gas pipelines and natural gas distribution facilities in BC, which includes approximately 20,800 kilometers of transmission pipelines and distribution mains. TGI's distribution network serves close to 88 per cent of natural gas customers in BC and delivers more than 20 per cent of the Province's energy needs.

Service Areas

These General Terms and Conditions of Terasen Gas refer to the following major Service Areas: Lower Mainland, Inland, Columbia and Fort Nelson.

Lower Mainland Service Area Means the areas including, but not limited to, the following locations and surrounding areas of

Abbotsford	New Westminster
Anmore	North Vancouver City
Belcarra	North Vancouver Dist.
Burnaby	Pitt Meadows
Chilliwack	Port Coquitlam
Coquitlam	Port Moody
Delta	Richmond
Harrison Hot Springs	Squamish
Hope	Surrey
Kent	Vancouver
Langley City	West Vancouver
Langley District	White Rock
Maple Ridge	
Matsqui	
Mission	

C

Inland Service Area Means the areas including, but not limited to, the following locations and surrounding areas of

Armstrong	Nelson
Ashcroft	Okanagan Falls
Bear Lake	Oliver
Cache Creek	100 Mile House
Castlegar	108 Mile House
Chase	150 Mile House
Chetwynd	Osoyoos
Christina Lake	Oyama
Clinton	Peachland
Coldstream	Penticton

Inland Service Area (continued)

Collettville
Craigmont
Falkland
Ferguson Lake
Fruitvale

Gibralter Mines
Grand Forks
Greenlake
Greenwood
Hedley

Hixon
Honeymoon Creek
Hudson's Hope
Kamloops
Kelowna

Keremeos
Lac La Hache
Lakeview Heights
Logan Lake
Lumby

MacKenzie
Merritt
Midway
Montrose
Naramata

Prince George
Princeton
Quesnel
Revelstoke
Robson

Rossland
Salmo
Salmon Arm
Savona
Shelley

Sorrento
Spallumcheen
Summerland
Trail
Vernon

Warfield
Westbank
Westwold
Williams Lake
Winfield

Woodsdale

Columbia Service Area

Means the areas including, but not limited to, the following locations and surrounding areas of

Cranbrook
Creston
Elkford
Fernie
Galloway

Jaffray
Kimberley
Sparwood
Yahk

Fort Nelson Service Area

Means the areas including, but not limited to, the following locations and surrounding areas of

Fort Nelson
Prophet River

Regulatory History

The regulatory model used to set rates for the Company has evolved over the last fifteen years and moved away from traditional cost of service regulation towards incentive-based ratemaking models. Since 1994, the Company has operated under an evolving model of performance-based ratemaking ("PBR") through settlements negotiated with customers and approved by the Commission. PBR models seek to enhance the performance of utilities through the use of incentive mechanisms not found in traditional cost of service regulation. A common theme that emerges is the need to break or weaken the link between costs and rates so to enhance the incentive for utilities to reduce costs. In the regulatory processes leading to the past PBR plan settlements, parties have participated in the exchange of information, commentary, workshops, analyses, negotiations and settlement discussions. The processes culminated in agreements containing incentives to enhance utility performance while maintaining excellent customer service, and established ongoing annual reviews to monitor the PBR results in a Commission sponsored process. The comprehensive PBR plans (1998-2001 and 2004-2009) have also included earnings sharing mechanisms by which customers have shared in the benefits achieved. Therefore, these settlements have moved the interests of the Company and customers into closer alignment and have encouraged the attainment of greater efficiencies.

In 1997, the Commission approved a PBR Plan for the three years from 1998 to 2000. In 2000, by agreement of customers and the Company, and as approved by the BCUC, the PBR Plan was extended to include 2001. During this period, the Company undertook initiatives to meet and exceed productivity targets in the PBR Plan without deterioration in the quality of service to customers. These initiatives led to a significant reduction of the Company's workforce and to the achievement of operating cost per customer efficiencies. Although the Company achieved a high level of performance in the area that was the primary focus of the incentives in the 1998 - 2001 PBR Plan, namely O&M expenses, the delivery rates of the Company increased during this term of the PBR Plan. The primary driver of this increase was the necessary and required investment in capital to provide safe, reliable and efficient service to customer. Under the 1998 - 2001 PBR Plan, the extent to which the Company could recover restructuring costs was dampened by the absence of an adequate multi-year payback mechanism in the areas of capital expenditures and operating costs.

On August 24, 2001 Terasen Gas filed a revenue requirement application for 2002 seeking a 7 percent increase in delivery rates, corresponding to an approximate 2 percent increase in burner-tip rates. On November 1, 2001 Terasen Gas filed notice with the Commission that it was withdrawing its 2002 revenue requirement application. After an information session regarding the application withdrawal on November 8, 2001 and intervenor submissions on November 9, 2001 the Commission issued Order No. G-123-01 and Reasons for Decision approving the withdrawal of the application and directing Terasen Gas to address certain matters raised in the Reasons for Decision in its 2003 Revenue Requirements Application. As a result, the 2001 base delivery rates remained in effect throughout 2002.

On June 17, 2002, Terasen Gas filed a 2003 Revenue Requirements and Multi-Year Performance-Based Ratemaking Application seeking approval for its 2003 revenue requirement, approval to determine its 2003 rates and to establish a comprehensive multi-year performance-based rate plan for 2003 to 2007 through a negotiated settlement process. A public hearing was held commencing November 12, 2002 for the review of 2003 revenue requirements and the Commission issued its Decision on February 4, 2003. That Decision reviewed the Company's costs and revenues, and established rates for 2003. At page 53, the Commission's Decision stated:

> *"The Commission anticipates that [Terasen Gas] will file, early in 2003, a multiyear PBR Application for revenue requirements for 2004 and beyond which incorporates the determinations made in this Decision. The Commission would then establish a procedure in accordance with the Commission's Negotiated Settlement Process Guidelines."*

On April 17, 2003, Terasen Gas filed its Multi-Year Performance Based Rate ("PBR") Plan for 2004 – 2008. Following a Negotiated Settlement Process, by Order No. G-51-03 dated July 29, 2003, the Commission accepted the agreement reached by parties, which was based on a four-year term rather than the proposed five-year term and thus approved the 2004-2007 Multi-Year Performance-Based Rate Plan Settlement (the "2004-2007 PBR Settlement Agreement"). The key elements in this order included:

- Allowed O&M costs and base capital expenditures set on an incentive formula basis;
- 50:50 sharing between customers and the Company of achieved efficiencies (after paying for restructuring costs) beyond those already embedded in the O&M and the base capital expenditure formulas;
- Restructuring costs funded through achieved efficiencies, not from customers;
- Mechanisms to continue the incentive to invest in efficiencies throughout the term of the plan;
- Results-based Service Quality Indicators;
- 4-year term with opportunity for mid-term review/adjustments;
- An Annual Review process and other provisions to keep customers informed of the functioning of PBR settlement agreement such as a mid-term review process and the formation of a Customer Advisory Council.

In carrying out the provisions of the 2004-2007 PBR Settlement Agreement Terasen Gas delivered significant value to its customers relative to what would have been achieved under traditional cost of service regulation. Some of the benefits achieved include lower delivery rates through achieved efficiencies, greater certainty in delivery rates by establishing results-based formulas and improved regulatory and administrative efficiency. The most important benefit of PBR is that it fostered strong alignment between customer and Company interests by encouraging innovation, customer focus and the on-going pursuit of operating efficiencies. The interests of customers were also well served in the 2004-2007 PBR Settlement through other means such as the Customer Advisory Council (which met twice yearly during the PBR term), the requirement for Terasen Gas to meet and measure customer service levels through an extensive set of Service Quality Indicators ("SQIs"), Annual Reviews and the Mid-term Assessment Review.

For 2004 and onwards, the Company was required to update its forecast of customer additions, use per account and industrial revenues annually. The impact on revenues resulting from the updated forecasts would be flowed through in delivery rates in the following year. The settlement also provided for the flow through of the impacts of changes approved by BCUC orders and exogenous factors. The terms of the Settlement Agreement also required Terasen Gas to hold a Mid-Term Assessment Review to provide an expanded annual review and information on its current and future year activities prior to the end of the third year (2006) of the Settlement Agreement.

On January 19, 2007, shortly after the Mid-Term Assessment Review, Terasen Gas filed its Application for the Approval of a Two-Year Extension (2008-2009) of the Settlement Agreement (the "Extended Settlement Agreement"). By Order No. G-33-07 dated March 23, 2007 the Commission approved the two-year extension of the 2004-2007 Multi-Year Performance-Based Rate Plan.

The annual reviews have been a process for the Company and stakeholders to ensure that the objectives of the Settlement Agreement were being achieved and to review the cost drivers and financial forecasts for the purposes of establishing revenue requirements for the following year. The Company has performed well during the last six years in delivering value to its customers. In addition to achieving efficiencies, the Company implemented comprehensive and customer-focused service quality assurance measures ("Service Quality Indicators" or "SQIs") to ensure that service quality standards are maintained throughout the term of the PBR. Moreover, customers have received benefits from the Company's continued efficiencies through the 50:50 sharing mechanism, whereby significant amounts have been refunded to customers through Earnings Sharing Mechanism ("ESM") riders.

The following sections will provide a synopsis of the Company's annual review application and Commission's decision for each year from 2003 to 2008.

A. 2003 Annual Review of 2004 Revenue Requirements

On October 31, 2003, TGI filed its Annual review advance material for a 2004 revenue requirement increase of $17.4 million, equivalent to a 3.71 per cent increase in gross margin or a 1.25 per cent increase in total revenue at existing rates. This filling also contained a business case study on the separation of Terasen Inc. and the creation of a corporate centre as directed in the 2003 Decision.

On November 28, 2003, TGI applied for approval of its 2004 Revenue Requirements and delivery rates pursuant to sections 58, 60 and 61 of the Act and the terms of the Settlement Agreement. The application requested approval to increase delivery rates by 4.3 percent to recover a 2004 revenue deficiency of $19.15 million.

By Order No. G-80-03, dated December 17, 2003, the Commission approved TGI's request for an increase in delivery rates effective January 1, 2004. The key drivers contributing to the revenue requirement increase were:

- Lower residential and commercial use rates
- Higher depreciation and amortization
- Change in accounting for Transmission Pipeline Integrity Program ("TPIP") expenditures
- Higher O&M per formula
- Higher rate base due to plant additions

The Commission also approved the following:

- The cancellation of the ten-month rider that was established by Commission Order No. G-7-03. This rider recovered the foregone January/February 2003 rate increase over the remaining the months of 2003.
- An increase in the RSAM rider by $0.061/GJ from $0.134/GJ to $0.195/GJ.

The Commission denied the following requests:

- The increase property tax incentive from 10 percent to 25 percent
- The Utility Asset Utilization Incentive
- The incentive for pension and insurance costs similar to the property tax incentive mechanism

B. 2004 Annual Review of 2005 Revenue Requirements

On October 29, 2004, TGI filed its Annual Review advance materials for a 2005 revenue requirement decrease of $1.0 million, equivalent to a 0.21 per cent decrease in gross margin or a 0.07 per cent decrease in total revenue at existing rates.

On November 26, 2004, TGI applied for approval of its 2005 Revenue Requirements and delivery rates pursuant to sections 58, 60 and 61 of the Act and the terms of the Settlement Agreement. The 2005 revenue requirement calculations determined according to the provisions of the Settlement Agreement resulted in a revenue requirement decrease of $2.108 million. This revenue surplus corresponded to an overall 0.42 per cent decrease in gross margin or a 0.15 per cent decrease in revenue. After excluding bypass and special rate revenues, the decrease in delivery rates for customers subject to general revenue requirement decrease was 0.45 per cent.

TGI also requested approval for the following:

- to decrease the Revenue Stabilization Adjustment Mechanism ("RSAM") rider applicable to the residential and commercial rate classes from $0.195/GJ to $0.143/GJ;
- Earnings Sharing Mechanism ("ESM") riders for the customers' portion of the projected 2004 earnings shortfall of $204,000, representing 0.04 percent of the gross margin;
- to transfer the balance of the Coastal Facilities assets into rate base and finance by 67 percent debt and 33 percent equity (the approved capital structure then in effect);
- to utilize customer security deposits as a substitute for short-term borrowing; and
- to establish deferral accounts for OSC compliance costs and BCUC levies, as the cost increases associated with these items were deemed to be exogenous factors.

By Order No. G-112-04 dated December 15, 2004, the Commission approved TGI's request for a decrease in delivery rates effective January 1, 2005. The key drivers contributing to the revenue requirement decrease were:

- Customer growth and industrial revenue changes
- Higher other revenues from the Southern Crossing Pipeline ("SCP")
- Change in pension and insurance forecast
- Lower income taxes
- Large Corporations Tax rate reduction
- Lower depreciation and amortization
- Change in use rates

C. 2005 Annual Review of 2006 Revenue Requirements

TGI filed its Annual Review advance materials on October 19, 2005 seeking a 2006 net revenue requirement increase of $14.3 million after application of the Earnings Sharing Mechanism of the Settlement.

On November 7, 2005, TGI revised the net revenue requirement increase to $10.7 million in accordance with Commission Order No. G-98-05 that approved transactions related to the Southern Crossing Pipeline ("SCP"). Commission Order No. G-98-05 required the debiting of an annual charge of $3.6 million (based on monthly installments) against the Midstream Cost Reconciliation Account, with an equal and offsetting amount to be credited to the delivery margin revenue account, for a limited period as a unique transaction in the circumstances of the SCP and the termination of the BC Hydro Transportation Service Agreement.

After taking into consideration the earnings surplus incentive sharing, the revenue requirement for 2006 increase was $10.7 million, equivalent to a 2.19 per cent increase in gross margin, or a 0.65 per cent increase in total revenue at existing rates.

On December 2, 2005, TGI applied for approval of its 2006 Revenue Requirements and delivery rates pursuant to sections 58, 60 and 61 of the Act and the terms of the Settlement Agreement. The 2006 revenue requirement calculations determined according to the provisions of the Settlement Agreement resulted in a revenue requirement increase of $18.044 million. This revenue deficiency corresponded to an overall 3.68 per cent increase in gross margin or a 1.10 per cent increase in revenue. After excluding bypass and special rate revenues, the increase in delivery rates for customers subject to the general revenue requirement increase was 3.90 per cent.

TGI also requested the following approvals:

- to continue the 2005 approved return on equity of 9.03 percent and common equity component of 33 percent for the purpose of setting interim rates for 2006;
- to increase the RSAM rider by $0.023/GJ from the currently approved level of $0.143/GJ to $0.166/GJ;
- customers' portion of the 2005 ESM surplus projected at $6.0 million on a pre-tax basis, equivalent to a refund of 1.30 percent of gross margin;
- to establish deferral treatment for the net book value difference of $1.533 million resulting from the replacement on November 1, 2005 of the existing fleet service provider, from BC Hydro to PHH Arval, and to amortize over 3 years commencing January 1, 2006 this difference between BC Hydro's stated net book value and the fair market value assigned by PHH Arval.

On December 14, 2005, by Order No. G-132-05, the Commission approved TGI's 2006 request for an increase in delivery rates on an interim basis effective January 1, 2006, subject to refund with interest at the average prime rate of TGI's principal bank. The key drivers contributing to the revenue requirement increase were:

- Lower use rates
- Higher rate base due to plant additions
- Lower revenue from the SCP
- Higher depreciation and amortization

D. 2006 Annual Review of 2007 Revenue Requirements

On October 16, 2006, TGI filed its Annual Review advance materials in accordance with the regulatory timetable established by Order No. G-121-06. The Annual Review advance materials included a request that the Commission approve the amalgamation of Terasen Gas and Terasen Gas (Squamish) Inc. ("Terasen Squamish", "TGS"), effective January 1, 2007. The amalgamated 2007 revenue requirement identified in the Annual Review advance materials was for a rate decrease of $4.1 million, equivalent to a 0.8 per cent decrease in gross margin or a 0.3 per cent decrease in total revenue at existing rates. After taking into consideration the customer portion of the ESM surplus, the decrease was $16.8 million, equivalent to a 3.4 per cent decrease in gross margin, or a 1.2 per cent decrease in total revenue at existing rates.

On December 1, 2006, TGI applied for approval of its 2007 Revenue Requirements and delivery rates pursuant to sections 58, 60 and 61 of the Act and the terms of the Settlement Agreement. The 2007 revenue requirement calculations determined according to the provisions of the Settlement Agreement resulted in a revenue requirement decrease of $9.6 million. This revenue surplus corresponded to an overall 1.87 per cent decrease in gross margin or a 0.65per cent decrease in revenue. After excluding bypass and special rate revenues, the decrease in delivery rates for customers subject to the general revenue requirement decrease was 0.60 per cent. The key drivers contributing to the revenue requirement decrease were:

- Elimination of the large corporations tax
- Lower rate base and others
- Change in the pension and insurance forecast
- Change in customer growth
- Higher income tax deductions

By Order No. G-160-06, dated December 18, 2006, the Commission accepted TGI's opinion regarding the applicability of sections 41, 50, 52, 53 and 54 of the Act to the amalgamation of TGI and TGS. The Commission agreed that Commission approval was not required for the amalgamation of TGI and TGS. The Commission approved the cancellation of TGI Tariff Supplement I-3 and TGS Tariff, effective January 1, 2007. In accordance with Special Direction No. 3, the Commission approved the amalgamated of TGI and TGS.

The Commission approved the $0.021/GJ decrease in the Rate Stabilization Adjustment Mechanism rider from $0.166/GJ to $0.145/GJ, effective January 1, 2007.

The Commission also approved customers' portion of the 2006 ESM surplus projected at $8.2 million on a pre-tax basis, representing 1.69 percent of the gross margin;

Furthermore, the Commission approved the establishment of a rate base deferral account to record the $10 million payment and the cost of the Social Service Tax appeal, subject to the $414 million SCP Project maximum capital cost approved by Commission Order No. G-95-00.

The Commission accepted the TGI submission that the inclusion of non-executive bonuses in pension costs recovered from customers and the exclusion of executive bonuses in pension costs recovered from customers is consistent with Commission's 1992, 1994 and 2003 Decisions.

Finally, the Commission accepted TGI's submission that terms of the Settlement prevent it from increasing the Demand-Side Management ("DSM") incentive grants over the $1.5 million during the period of the Settlement. TGI was instructed to include the Ratepayer Impact Measure test, the Participant Cost test and the percentage of "free riders" for the each program in the 2006 DSM portfolio and in future DSM reports.

E. 2007 Annual Review of 2008 Revenue Requirements

On October 5, 2007, TGI filed its Annual Review advance materials in accordance with the regulatory timetable established by Order No. G-112-07. The 2008 revenue requirement increase identified in the Annual Review advance materials was $5.6 million, equivalent to a 1.1 per cent increase in gross margin or a 0.4 per cent increase in total revenue at existing rates. After taking into consideration the ESM surplus incentive sharing, the revenue requirement was a decrease of $9.4 million, equivalent to a 1.9 per cent decrease in gross margin, or a 0.6 per cent decrease in total revenue at existing rates. The key drivers contributing to the revenue requirement decrease were:

- Higher income tax deductions
- Change in pension and insurance forecast
- Lower depreciation and amortization
- Lower income tax rates

On November 2, 2007, TGI filed three revisions to the October 5, 2007 Annual Review advance materials, resulting in a revised 2008 revenue requirement increase of $5.3 million. These revisions included changes to depreciation and amortization expense, interest expense, and income tax deductions. After taking into consideration the ESM surplus incentive sharing of $15 million, the revenue requirement was a decrease of $9.7 million.

On November 30, 2007, TGI applied for approval of its 2008 Revenue Requirements and delivery rates pursuant to sections 58, 60 and 61 of the Act and the terms of the Settlement Agreement. The revised 2008 revenue requirement calculations determined according to the provisions of the Extended Settlement resulted in a revenue requirement increase of $9.43 million, before consideration of the customer portion of the Earnings Sharing Mechanism. This revenue requirement corresponded to an overall 1.89 per cent increase in gross margin or a 0.62 per cent increase in revenue. After excluding bypass and special rate revenues, the increase in delivery rates for customers subject to the general revenue requirement was a 0.57 per cent increase in revenue. After taking into consideration the earnings surplus incentive sharing of $15.0 million the revenue requirement was a decrease of $5.6 million, equivalent to a 1.1 per cent decrease in gross margin. The further impact on revenue decrease was due to amended TGVI Wheeling Revenue and final TGI ROE decision of 8.62 per cent.

By Order No. G-153-07, dated December 10, 2007, the Commission approved the following:

- the increase of applicable charges for customers served under Rate Schedules 1, 1S, 2, 2U, 3, 3U, 4, 5, 6, 7, 22, 22A, 22B, 23, 25, and 27 effective January 1, 2008, as provided in the Revised Application;
- customers' portion of the 2007 incentive earnings surplus projected at $12.6 million on a pre-tax basis, representing 2.67 percent of the gross margin; the $0.05/GJ decrease in the Rate Stabilization Adjustment Mechanism rider from the currently approved level of $0.145/GJ to $0.095/GJ, effective January 1, 2008;
- the continuation of the rate base deferral account established for the ongoing Provincial Sales Tax appeal related to the Southern Crossing Pipeline project;
- the establishment of a rate base deferral account to record any differences to be amortized in the following year;
- the establishment of a rate base deferral account to record cost of service reductions related to the timing of the Lochburn land sale; and
- the request for TGI to follow Section 3061.04 of the CICA Handbook revision that will result in a reclassification in TGI's financial statements between inventory and property, plant and equipment for pipe, valves, fittings and other items that would ultimately be used for gas plant in service, whereby these costs will be transferred to Plant Work in Process ("WIP") in the financial statements, effective January 1, 2009, as described in the Advance Materials.

F. 2008 Annual Review of 2009 Revenue Requirements

On October 8, 2008, TGI filed the Annual Review advance materials for the purposes of setting rates for 2009 in accordance with the regulatory timetable established by Commission Order G-142-08.The 2009 revenue requirement increase identified in the Annual Review advance materials was $36.3 million, equivalent to a 7.5 per cent increase in gross margin or a 2.2 per cent increase in total revenue at existing rates. After taking into consideration the earnings surplus incentive sharing, the revenue requirement was an increase of $21.9 million, equivalent to a 4.6 per cent increase in gross margin, or a 1.3 per cent increase in total revenue at existing rates. The key drivers contributing to the revenue requirement increase were:

- Change in use rate
- Higher depreciation and amortization
- Higher property taxes
- Higher O&M
- Lower income tax deductions
- Higher rate base to support customer growth

TGI requested deferral account treatment for incremental costs associated with the implementation of International Financial Reporting Standards ("IFRS") to be amortized beginning in 2011, a deferral account treatment of incremental costs for Olympic and Paralympic Games Security to be amortized beginning 2011, a change to the amortization of the Large Corporations Tax deferral account, and changes to the non rate base Residential and Commercial Commodity Unbundling deferral accounts.

On November 3, 2008, TGI filed a revision to the October 8, 2008 Advance Materials filing including updated financial schedules to reflect changing economic circumstances related to industrial forecast and customer addition assumptions.

On December 3, 2008, TGI applied for approval of its 2009 Revenue Requirements and delivery rates pursuant to sections 58, 60 and 61 of the Act and the terms of the Extended Settlement Agreement. The revised 2009 revenue requirement calculations determined according to the provisions of the Extended Settlement Agreement resulted in a revenue requirement increase of $35.12 million, before consideration of the customer portion of the Earnings Sharing Mechanism. This revenue requirement corresponded to an overall 7.30 per cent increase in gross margin or a 2.10 per cent increase in revenue. After excluding bypass and special rate revenues, the increase in delivery rates for customers subject to the general revenue requirement was a 1.95 per cent increase in revenue.

By Order No. G-191-08, dated December 11, 2008, the Commission approved the following:

- customers' portion of the 2008 incentive earnings surplus projected at $12.0 million on a pre-tax basis, representing 2.61 percent of the gross margin;
- the $0.093/GJ decrease in the Rate Stabilization Adjustment Mechanism rider from the currently approved level of $0.094/GJ to $0.001/GJ effective January 1, 2009;
- the establishment of a rate base deferral account to recover the critical security costs associated with the 2010 Olympic and Paralympic Winter Games;
- the establishment of a rate base deferral account to recover the incremental costs associated with IFRS implementation;
- the change to the amortization of the Large Corporations Tax deferral account; and
- the changes to the non rate base Residential and Commercial Commodity Unbundling deferral accounts.

TGI was ordered to revise its 2009 forecast to account for any direction from the review of the Customer Choice operating and capital expenditure budgets. The Commission also ordered that if there is delay in the issuance of the Customer Choice Decision then TGI should record the difference between the 2009 budget and the 2009 allowed operating expenditures and capital expenditures in rate base deferral accounts for disposition in next year's revenue requirements.

G. Summary

As discussed above, TGI has lived up to the expectations of its regulatory commitments through the settlement period. During this period, the Company performed well by achieving efficiencies and maintaining customer-focused service quality standards. Consequently, the Settlement Agreement and the Extended Settlement Agreement coupled with annual reviews have served their purpose by aligning the interest of the customers and the Company's shareholder.

Terasen Gas Inc
Annual Report Statistics
2003-2008

	2003	2004	2005	2006	2007	2008
Customers:						
12 Month Average Residential Customers	692,297	701,290	712,427	722,865	735,263	743,756
12 Month Average Commercial Customers	76,377	76,054	76,880	77,511	78,810	79,538
12 Month Average Industrial Customers	513	482	428	383	334	306
12 Month Average Transportation Customers	1,389	1,595	1,819	1,947	1,984	2,066
12 Month Average NGV Customers	48	40	39	37	36	30
Total Average Customers	**770,624**	**779,461**	**791,593**	**802,743**	**816,427**	**825,696**
Total Year End Customers	775,516	787,020	799,365	809,559	822,598	831,845
Gas Deliveries (Actual):						
Residential Gas Delivery (TJ)	68,361	66,026	68,962	68,240	70,638	68,841
Commercial Gas Delivery (TJ)	38,418	37,770	38,422	37,767	39,581	39,667
Industrial Gas Delivery (TJ)	5,829	5,117	4,547	4,072	3,692	3,408
Transportation Gas Delivery (TJ)	96,719	101,697	99,923	98,708	100,791	98,081
NGV Gas Delivery (TJ)	241	318	186	135	117	94
Total Gas Deliveries	**209,568**	**210,928**	**212,040**	**208,922**	**214,819**	**210,091**
Cost of Gas (Normalized)						
Average Cost of Gas Sold ($/GJ)	$ 7.03	$ 7.35	$ 8.45	$ 9.13	$ 8.45	$ 8.91
O&M:						
Approved CPI (BC)	1.7%	1.7%	2.0%	2.2%	2.0%	2.0%
Gross O&M Decision (adj for Pension/Insurance)	$ 176,915	$ 192,390	$ 190,586	$ 196,919	$ 199,462	$ 200,052
Gross O&M Actual	$ 168,627	$ 176,951	$ 171,602	$ 180,026	$ 179,808	$ 186,479
Capitalization Allowed	-25,207	-26,009	-26,335	-27,243	-27,535	-27,684
Vehicle Lease	-1,918	-1,900	-1,911	-1,872	-2,008	-1,988
Coastal Lease	0	-4,505	0	0	0	0
Fort Nelson Allocation	-539	-611	-646	-688	-701	-599
Total Net O&M	**$ 140,963**	**$ 143,926**	**$ 142,710**	**$ 150,223**	**$ 149,564**	**$ 156,208**
Headcount						
Average Full Time Equivalent (FTE)	1,190	1,089	1,092	1,062	1,087	1,127
Distribution Fast Facts:						
Outages caused by Third Party	1,459	1,491	1,457	1,434	1,545	1,574
Gas Odour Calls	21,347	21,861	20,443	23,497	22,792	20,335
CO Calls	1,512	1,405	1,418	1,224	1,573	1,583
Fire Calls	712	610	733	882	996	973
Meter Recalls	45,142	45,185	45,448	28,457	32,175	33,275
Locates	324	2,523	1,837	1,739	2,378	3,153
Calls to BC 1 Call	46,500	46,500	46,500	46,500	58,000	41,000
Lock Offs - Interior	15,845	12,973	10,582	8,949	9,567	10,623
Lock Offs - Coastal	905	1,807	1,414	1,105	1,657	1,628
Unlocks - Interior	15,006	8,767	11,093	9,478	9,936	10,431
Unlocks - Coastal	30,521	24,210	22,118	20,326	23,888	22,530
Service Lines (Risers)	713,700	713,700	713,700	713,700	743,928	735,891
# of Main Valves	9,438	9,438	9,438	9,438	9,425	9,024
# of Service Valves	16,994	16,994	16,994	16,994	16,960	16,735
Regulator Stations	416	416	416	416	416	390
Line Heaters	200	200	200	200	200	245
Budgeted FTE - Distribution	510	499	488	468	481	503
Pipeline Stats:						
Total TP Pipe (KM's)	2,415	2,415	2,415	2,415	2,418	2,418
Total IP (KM's)	350	350	350	350	516	511
Total DP Service Pipe (KM's)	16,700	16,964	17,205	17,455	17,655	17,872
Total DP Main Pipe (KM's)	18,300	18,651	19,018	19,377	19,730	20,123
Total LP Pipe (KM's)	100	100	100	100	58	24
Total Pipeline	**37,865**	**38,480**	**39,088**	**39,697**	**40,377**	**40,948**
System Outages:						
Outages	1,532	1,566	2,291	2,414	2,935	2,638
Customers Affected	2,857	3,912	3,981	2,691	3,631	2,772
System Leaks:						
Transmission Pipeline Leaks	3	3	3	1	1	2
Distribution Pipeline Leaks	134	150	120	71	87	57
Emergency Response Time (minutes)	22:00	21:36	21:42	21:24	20:36	20:42
Service Quality Indicators:						
Emergency Calls Answered in 30 seconds	96.3%	97.9%	99.0%	98.7%	98.4%	98.3%
% of Transportation Customer Bills Accurate	99.8%	96.6%	99.9%	99.9%	99.5%	94.3%
Customer Satisfaction	73.9%	73.9%	77.2%	77.9%	79.3%	79.7%
Customer Complaints to BCUC	101	191	100	145	130	90
Miscellaneous:						
Rate Base, Mid-Year	$ 2,249,535	$ 2,305,591	$ 2,408,090	$ 2,442,636	$ 2,425,545	$ 2,471,877
Allowed Return	9.420%	9.150%	9.03%	8.80%	8.37%	8.62%

Appendix C

EXTERNAL SITUATIONAL CONTEXT

(view Attachments Panel in Adobe

to access Contents of Appendix C)

Appendix D

GAS SALES AND TRANSPORTATION DEMAND

TGI CUSTOMER ADDITIONS 1999 - 2008

Lower Mainland Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Residential[1]	7,046	4,804	4,739	5,282	4,892	7,802	7,833	6,159	5,230	4,636
Commercial[2]	1,278	355	347	-1,000	-716	371	673	355	541	895
Industrial & Transportation[3]	223	80	13	48	-4	19	-4	-54	-44	-3
Total Net Additions	**8,547**	**5,239**	**5,099**	**4,330**	**4,172**	**8,192**	**8,502**	**6,460**	**5,727**	**5,528**
Year-End Customers	524,126	529,365	534,464	538,794	542,966	551,158	559,660	569,244[4]	574,971	580,499

Inland Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Residential[1]	4,244	734	108	1,961	1,380	2,759	3,385	3,243	3,671	3,040
Commercial[2]	328	349	-300	179	-15	352	306	286	141	342
Industrial & Transportation[3]	16	-1	4	-2	4	12	-4	-11	-12	-3
Total Net Additions	**4,588**	**1,082**	**-188**	**2,138**	**1,369**	**3,123**	**3,687**	**3,518**	**3,800**	**3,379**
Year-End Customers	205,553	206,635	206,447	208,585	209,954	213,077	216,764	220,282	224,082	227,461

Columbia Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Residential[1]	456	141	-1	120	46	111	194	181	346	267
Commercial[2]	40	63	-26	14	-28	23	22	11	10	46
Industrial & Transportation[3]	2	4	-3	3	2	1	-1	-4	0	0
Total Net Additions	**498**	**208**	**-30**	**137**	**20**	**135**	**215**	**188**	**356**	**313**
Year-End Customers	20,771	20,979	20,949	21,086	21,106	21,241	21,456	21,644	22,000	22,313

Revelstoke Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Residential[1]	22	7	-11	-3	-12	44	15	12	30	16
Commercial[2]	8	8	-5	4	-3	10	1	3	2	11
Total Net Additions	**30**	**15**	**-16**	**1**	**-15**	**54**	**16**	**15**	**32**	**27**
Year-End Customers	1,443	1,458	1,442	1,443	1,428	1,482	1,498	1,513	1,545	1,572

TGI Consolidated - All Regions:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Residential[1]	11,768	5,686	4,835	7,360	6,306	10,716	11,427	9,595	9,277	7,959
Commercial[2]	1,654	775	16	-803	-762	756	1,002	655	694	1,294
Industrial & Transportation[3]	241	83	14	49	2	32	-9	-69	-56	-6
Total Net Additions	**13,663**	**6,544**	**4,865**	**6,606**	**5,546**	**11,504**	**12,420**	**10,181**	**9,915**	**9,247**
Total Gross Additions	**15,450**	**7,400**	**5,300**	**8,300**	**12,837**	**15,549**	**12,770**	**13,338**	**15,533**	**14,566**
Year-End Customers	751,893	758,437	763,302	769,908	775,454	786,958	799,378	812,683[4]	822,598	831,845
Housing Starts[5]	16,309	14,418	17,234	21,625	26,174	32,925	34,667	36,443	39,195	34,321

Notes:

1. Rate 1
2. Rates 2, 3, and 23
3. Rates 4, 5, 6, 7, 22, 25, and 27
4. Includes 3,124 additional customers due to Squamish amalgamation
5. Source: CMHC

ACTUAL ENERGY DEMAND 1999 - 2008 (PJs)

Lower Mainland Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Residential	57.6	56.0	50.9	56.2	50.7	48.4	51.1	51.3	56.2	58.8
Commercial	39.4	37.2	34.2	35.2	32.2	32.2	33.4	33.8	37.3	38.6
Firm Sales	6.9	8.4	7.2	5.5	4.7	4.3	3.8	3.4	3.1	2.8
Industrial	27.3	25.2	24.8	28.4	28.1	18.7	28.7	28.0	27.5	26.5
Total	**131.3**	**126.9**	**117.1**	**125.3**	**115.6**	**103.6**	**117.0**	**116.5**	**124.1**	**126.6**

Inland Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Residential	17.8	18.5	16.1	16.7	15.9	15.8	16.0	15.4	16.7	17.6
Commercial	9.8	10.0	8.8	9.1	8.7	8.7	8.9	8.6	9.5	10.1
Firm Sales	2.2	2.5	1.6	1.4	1.2	1.0	0.8	0.7	0.6	0.5
Industrial	29.7	30.1	27.2	28.2	26.9	24.0	26.6	25.6	25.8	21.0
Total	**59.5**	**61.0**	**53.7**	**55.4**	**52.7**	**49.5**	**52.4**	**50.3**	**52.6**	**49.3**

Columbia Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Residential	2.0	1.9	2.1	1.7	1.7	1.8	1.7	1.6	1.7	1.8
Commercial	1.0	1.0	1.2	0.9	0.9	1.0	0.9	0.9	1.0	1.1
Firm Sales	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.0	0.0
Industrial	4.6	5.3	4.1	3.7	3.5	3.3	3.4	3.0	3.2	3.5
Total	**7.9**	**8.5**	**7.5**	**6.5**	**6.2**	**6.1**	**6.1**	**5.6**	**5.9**	**6.3**

Revelstoke Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Residential	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial	0.1	0.2	0.2	0.1	0.1	0.2	0.1	0.1	0.1	0.1
Total	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**

TGI Consolidated - All Regions:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Residential	77.5	76.5	69.1	74.7	68.4	66.0	69.0	68.4	74.6	78.2
Commercial	50.4	48.4	44.3	45.4	42.0	42.1	43.4	43.4	48.0	49.9
Firm Sales	9.3	11.2	9.0	6.9	6.1	5.3	4.7	4.1	3.8	3.5
Industrial	61.6	60.6	56.1	59.4	60.1	58.3	58.6	54.2	56.3	51.8
Total	**198.9**	**196.7**	**178.5**	**186.5**	**176.6**	**171.6**	**175.7**	**170.1**	**182.6**	**183.4**

Notes:

The data illustrated above is not normalized for weather, and therefore differs from the figures illustrated within the main body of this Application

NORMALIZED ACTUAL ENERGY DEMAND 1999 - 2008 (PJs)

Lower Mainland Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Residential	56.5	55.1	48.8	54.2	54.0	53.9	51.6	52.1	52.7	51.6
Commercial	40.3	36.4	33.8	34.3	34.8	35.1	33.9	34.0	35.2	35.7
Firm Sales	6.9	8.4	7.2	5.4	4.8	4.2	3.8	3.4	3.1	2.9
Industrial	27.3	25.2	24.8	27.9	29.6	27.1	28.6	28.0	27.3	26.8
Total	**131.0**	**125.1**	**114.6**	**121.8**	**123.1**	**120.2**	**118.0**	**117.5**	**118.3**	**117.0**

Inland Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Residential	19.0	18.4	16.1	16.5	16.7	16.4	15.9	16.1	16.1	15.5
Commercial	10.0	9.8	8.7	8.9	9.4	9.0	8.8	9.0	9.2	9.0
Firm Sales	2.2	2.5	1.6	1.3	1.2	1.0	0.8	0.7	0.6	0.5
Industrial	29.7	30.1	27.2	27.9	27.1	27.6	26.5	23.1	25.8	21.6
Total	**60.9**	**60.8**	**53.6**	**54.7**	**54.4**	**54.0**	**52.0**	**48.9**	**51.7**	**46.7**

Columbia Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Residential	2.1	1.9	1.9	1.8	1.8	1.7	1.7	1.7	1.7	1.7
Commercial	1.0	1.0	1.2	1.0	1.0	1.0	1.0	0.9	1.0	1.0
Firm Sales	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.0	0.0
Industrial	4.6	5.3	4.1	3.6	3.5	3.6	3.4	3.0	3.2	3.4
Total	**7.9**	**8.4**	**7.4**	**6.5**	**6.4**	**6.4**	**6.1**	**5.7**	**6.0**	**6.2**

Revelstoke Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Residential	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial	0.1	0.2	0.2	0.2	0.1	0.2	0.1	0.1	0.1	0.1
Total	**0.2**	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**

TGI Consolidated - All Regions:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Residential	77.8	75.4	68.4	72.6	72.6	72.0	69.3	70.0	70.6	68.8
Commercial	51.5	47.3	43.9	44.3	45.3	45.2	43.9	44.1	45.5	45.9
Firm Sales	9.6	10.9	8.9	6.9	6.1	5.3	4.7	4.1	3.8	3.5
Industrial	61.2	58.9	55.6	59.4	60.1	58.3	58.6	54.2	56.3	51.8
Total	**200.1**	**192.5**	**176.8**	**183.2**	**184.1**	**180.8**	**176.4**	**172.4**	**176.2**	**170.0**

ACTUAL USE PER CUSTOMER RATES 1999 - 2008 (GJ/yr)

Lower Mainland Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Rate 1	124.2	118.8	109.7	114.2	104.9	99.2	102.0	101.8	109.0	110.3
Rate 2	345	339	313	311	306	295	309	319	348	360
Rate 3	3,892	3,669	3,356	3,424	3,142	3,250	3,313	3,222	3,553	3,651
Rate 23	6,722	6,563	5,776	5,245	4,676	4,608	4,565	4,569	4,881	4,871

Inland Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Rate 1	97.0	99.2	87.7	88.8	84.0	82.4	82.0	79.0	82.5	84.0
Rate 2	302	317	287	288	276	275	282	274	296	306
Rate 3	4,050	3,346	3,371	3,405	3,432	3,422	3,468	3,376	3,576	3,723
Rate 23	11,339	9,752	6,135	5,783	5,731	5,506	4,790	5,016	5,379	5,313

Columbia Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Rate 1	107.4	109.3	108.0	90.0	94.2	87.1	89.3	82.8	86.6	87.4
Rate 2	365	395	398	317	332	326	326	318	336	349
Rate 3	3,640	3,554	3,809	3,267	3,191	3,439	3,637	3,340	3,551	3,989
Rate 23	N/A	N/A	3,148	2,877	3,063	3,737	4,326	4,341	4,674	4,730

Revelstoke Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Rate 1	75.8	75.6	71.5	67.3	59.9	64.4	62.0	69.2	59.5	51.7
Rate 2	374	332	349	343	342	349	350	285	307	317
Rate 3	5,518	6,244	7,095	6,895	5,945	7,769	5,836	4,649	4,677	4,358

TGI Consolidated - All Regions:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Rate 1	116.1	113.1	103.6	106.5	98.8	94.2	96.1	95.0	101.1	102.3
Rate 2	334	335	309	305	299	291	302	307	333	345
Rate 3	3,917	3,620	3,373	3,424	3,193	3,287	3,348	3,251	3,560	3,669
Rate 23	6,869	7,047	5,844	5,330	4,816	4,754	4,596	4,638	4,959	4,944

Notes:

The data illustrated above is not normalized for weather, and therefore differs from the figures illustrated within the main body of this Application

NORMALIZED ACTUAL USE PER CUSTOMER RATES 1999 - 2008 (GJ/yr)

Lower Mainland Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Rate 1	121.9	116.9	105.2	113.0	111.6	109.8	103.6	103.2	102.6	99.5
Rate 2	347	327	309	315	330	323	314	325	327	326
Rate 3	3,952	3,616	3,318	3,379	3,371	3,485	3,365	3,267	3,405	3,406
Rate 23	6,667	6,333	5,721	5,159	4,867	5,017	4,700	4,606	4,684	4,642

Inland Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Rate 1	103.8	98.8	87.5	88.0	88.7	85.7	81.9	81.6	80.3	76.0
Rate 2	330	311	285	285	296	286	281	286	286	273
Rate 3	4,410	3,892	3,288	3,361	3,702	3,524	3,451	3,536	3,500	3,426
Rate 23	12,627	9,489	6,334	5,605	5,816	5,713	4,792	5,140	5,273	4,998

Columbia Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Rate 1	113.3	107.9	95.6	95.5	95.9	90.5	89.2	86.8	86.8	83.0
Rate 2	390	389	347	302	338	340	330	328	340	336
Rate 3	3,847	3,521	3,487	3,141	3,358	3,566	3,681	3,409	3,619	3,898
Rate 23	N/A	N/A	2,799	2,500	3,691	3,852	4,324	4,498	4,637	4,516

Revelstoke Region:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Rate 1	81.9	74.4	69.7	66.2	69.3	70.6	63.6	68.9	57.9	49.2
Rate 2	401	331	343	339	349	370	354	313	297	301
Rate 3	5,633	6,136	7,051	6,872	6,529	8,049	5,914	4,954	4,581	4,211

TGI Consolidated - All Regions:

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Rate 1	116.7	111.7	100.5	105.6	103.1	102.6	97.4	96.8	96.0	92.5
Rate 2	344	325	305	302	304	314	306	314	317	326
Rate 3	4,025	3,660	3,332	3,378	3,292	3,501	3,388	3,314	3,426	3,406
Rate 23	6,817	6,447	5,802	5,281	4,883	5,113	4,714	4,686	4,778	4,642

TGI WEATHER DATA 1999 - 2008

Annual Heating Degree Days, by Region

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Lower Mainland[1]	2,853	2,901	2,856	2,844	2,667	2,525	2,664	2,714	2,889	3,043
Inland[2]	3,592	3,931	3,701	3,870	3,684	3,631	3,702	3,637	3,778	4,093
Columbia[3]	4,275	4,669	4,320	4,643	4,420	4,273	4,483	4,217	4,406	4,654
Revelstoke[4]	4,032	4,262	4,155	4,176	3,982	4,004	3,987	3,833	4,124	4,226

Notes:

1. Vancouver airport weather station

2 Simple average of the Castlegar, Kelowna, Penticton and Prince George airport weather stations

3. Cranbrook airport weather station

4. Revelstoke airport weather station

5. Heating degree days are based on an 18 degree Celsius control point: HDD_{18} = Maximum(0, 18 - Temperature)

Provincial Economic Outlook

BMO Capital Markets Economics
January 30, 2009

	Cda	BC	Alta	Sask	Man	Ont	Que	NB	NS	PEI	Nfld
Real GDP Growth (% change, chain-weighted)											
2006	**3.1**	4.4	6.1	-0.3	4.0	2.6	1.7	2.4	0.9	2.4	3.0
2007	**2.7**	3.0	3.1	2.5	3.3	2.3	2.6	1.7	1.7	2.4	9.1
2008 f	**0.6**	1.4	1.8	2.9	1.5	-0.2	0.2	1.0	1.1	0.8	1.3
2009 f	**-1.5**	-0.4	-0.9	1.0	-0.7	-2.4	-1.3	0.2	-0.4	-0.2	0.5
2010 f	**1.8**	1.7	1.6	1.4	1.6	2.0	1.9	1.7	1.6	1.2	2.0
Employment Growth (% change)											
2006	**1.9**	3.0	4.8	1.7	1.2	1.5	1.3	1.4	-0.3	0.5	0.7
2007	**2.3**	3.2	4.7	2.1	1.6	1.5	2.3	2.1	1.3	1.2	0.7
2008	**1.6**	2.1	2.8	2.1	1.7	1.5	0.8	0.9	1.2	1.3	1.5
2009 f	**-1.2**	-0.4	-0.5	1.0	-0.2	-2.1	-1.2	0.4	0.2	0.2	0.7
2010 f	**0.5**	0.7	0.5	0.7	0.2	0.4	0.3	0.4	0.2	0.5	1.9
Unemployment Rate (percent)											
2006	**6.3**	4.8	3.4	4.6	4.3	6.3	8.0	8.7	7.9	11.1	14.8
2007	**6.0**	4.2	3.5	4.2	4.4	6.4	7.2	7.6	8.1	10.3	13.6
2008	**6.1**	4.5	3.6	4.1	4.1	6.5	7.3	8.6	7.7	10.7	13.2
2009 f	**7.5**	6.1	4.9	4.8	5.4	8.4	8.1	9.7	8.7	10.8	12.9
2010 f	**7.9**	6.5	5.4	5.5	6.6	8.6	8.4	10.4	9.5	11.2	12.4
Housing Starts (thousands)											
2006	**229.1**	36.6	49.1	3.7	5.0	74.4	48.0	4.0	5.2	0.8	2.3
2007	**227.6**	39.2	48.1	5.9	5.8	68.0	48.5	4.1	4.7	0.7	2.6
2008	**213.7**	34.8	30.0	7.1	5.9	75.5	47.8	4.3	4.6	0.7	3.1
2009 f	**165.0**	27.1	25.0	6.3	4.6	55.0	36.5	3.4	3.3	0.6	3.2
2010 f	**170.0**	26.8	30.0	5.0	4.5	57.0	37.0	3.5	3.0	0.6	2.7
Consumer Price Index (% change)											
2006	**2.0**	1.7	3.9	2.0	1.9	1.8	1.7	1.7	2.1	2.2	1.8
2007	**2.1**	1.8	4.9	2.9	2.1	1.8	1.7	1.9	1.9	1.8	1.6
2008	**2.4**	2.1	3.2	3.2	2.2	2.3	2.1	1.7	3.0	3.4	2.9
2009 f	**0.5**	0.9	1.3	1.7	0.7	0.3	0.4	0.3	0.4	0.6	1.3
2010 f	**1.8**	1.9	2.0	1.7	1.5	1.8	1.7	1.8	1.7	1.8	2.0

TD Bank Financial Group

TD Economics

Provincial Economic Forecast

March 17, 2009

SYNCHRONICITY, THE 2009-10 CANADIAN TOUR

HIGHLIGHTS

- **Highly synchronous global recession rippling through all regions of Canada**
- **Global financial market and macroeconomic conditions overwhelm domestic drivers of local economies …**
- **… leaving little differentiation in regional fortunes this year**
- **Unemployment rates to surge by 3-4 percentage points by 2010 to reach 1990s levels for many provinces**
- **Commodity-based provinces' nominal incomes (GDP) get walloped the most**
- **Home construction and prices continue to unwind across the nation**
- **Retail spending to contract on slumping prices and volumes**

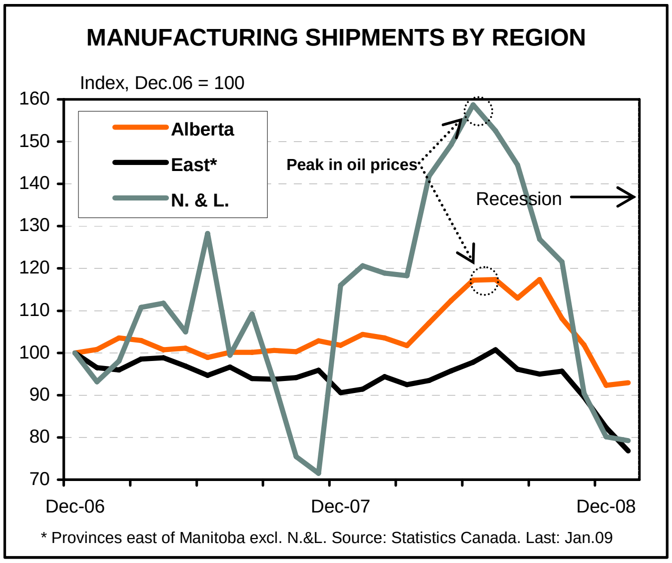
Our recent Quarterly Economic Forecast (March 12) argued that this is the most synchronous global downturn in the post-war period. It could also very well be the most synchronous downturn within Canada since the war. Indeed, all regions of the country have faltered in lockstep since the fourth quarter of 2008. This is the one reunion tour from the recession marching band we all would rather not attend. Plunging global demand for manufacturing exports, falling commodity prices and volumes, and financial market gyrations are affecting all regions. This is translating into broadly-based and significant drops in output and investment, as well as rising unemployment from coast to coast. In turn, fragile consumer confidence and job losses have led to contractions in consumer spending and suggest more hardship is yet to come. Government spending (all levels combined) is providing somewhat of a cushion, but cannot, by itself, take up this huge slack in private sector economic activity.

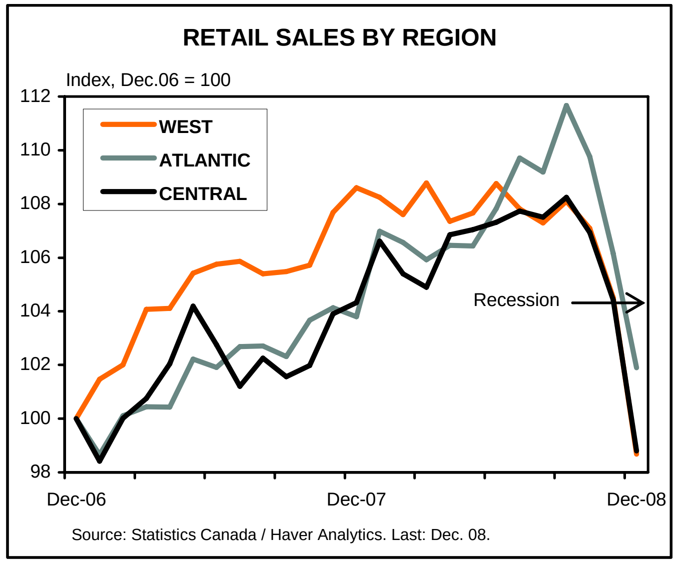
The accompanying charts reflect just how quick of a turnaround we have seen in regional monthly indicators like manufacturing shipments, retail sales, and employment. Furthermore, these regional aggregates clearly show when economic activity peaked, and how quickly it has slipped since then. This speaks volumes to the fact that global financial market and macroeconomic conditions are overwhelming the domestic drivers of local economies. The lack of significant differentiation between regions contrasts with the experience of recessions past, as the accompanying text box (page 4) shows.

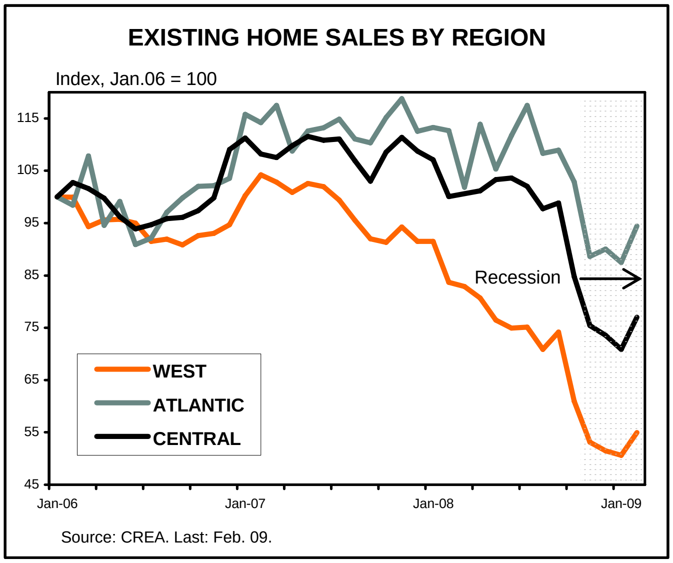
A year to forget

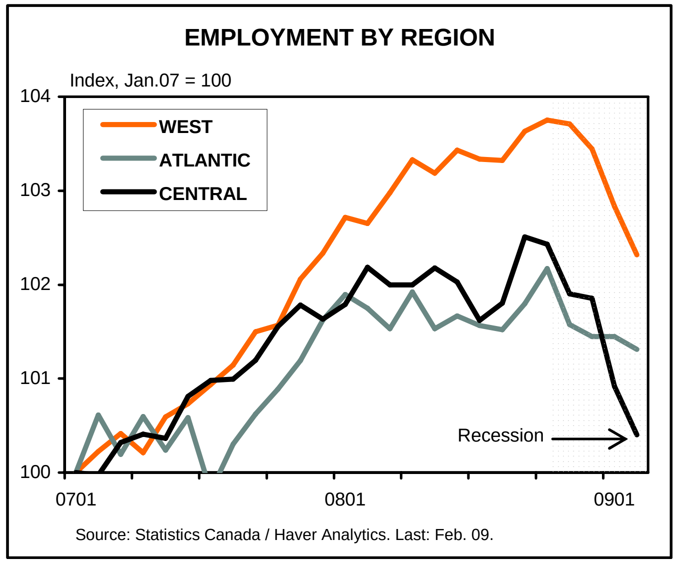
This year, most provinces can expect real GDP contractions close to that of the national economy, around 2.4%, with a couple of Prairie provinces (Manitoba and Saskatchewan) holding up slightly better. Nominal incomes (GDP) are being walloped, but here experiences will be more varied, with regions relying more heavily on commodities suffering through the swift return of the commodity price pendulum. Accordingly, the Prairies and Newfoundland & Labrador will experience larger than 5% pullbacks in nominal GDP, lead by Alberta's 10% decline. Other province's nominal GDP slippage should be less severe than that of the country as a whole (-4.5%), while in many cases still expected to record their worst historical performance.

The retail sales landscape is expected to align with these reversals in nominal incomes. As retail prices slump with firms lacking pricing power and volumes slipping, Canadian retail sales will record their first ever (data only goes









back to 1992) drop (-3.0%) on an annual average basis, led by 4-5% pullbacks in B.C. and Alberta. The experience of declining retail spending will be shared across all provinces.

Existing (resale) home sales and prices are projected to slip significantly this year vis-a-vis last year. We expect only 320,000 existing homes to be sold in 2009, or 26% fewer than a year prior. The pullback had already started in earnest in the second half of last year in B.C. and Alberta. This trend quickly generalized across the country within a matter of a few months, however. All provinces will see a significant double-digit percentage drop in home sales, not too far off from the national figures. As a result of much softer demand for homes, home values also started declining in the second half of 2008. We expect home prices to unwind by a further 13.5% this year on an annual average basis after a modest decline of 0.7% last year. More telling is the peak-to-trough measure, by which we expect national home prices to correct by 20-25%. Given the past froth experienced in some Western markets and the severity of the economic downturn in Ontario, these locales will lead the correction. Homebuilding has also been in full blown retreat since late last year. We currently expect an average of only 125,000 housing starts this year (41% fewer than in 2008) with a very modest uptick to 130,000 units next year.

All other indicators aside, it is the employment land-

FINANCIAL AND MACROECONOMIC ASSUMPTIONS

- **World** real GDP will shrink significantly (-1.6%) this year and grow only modestly (+2.2%) next year. The **G7** economies' pullback this year will be twice as much (-3.8%), followed by less than a third as much growth (0.7%). **U.S.** real GDP will contract by 3.1% in 2009, followed by a muted recovery which will limit growth to 1.4% percent in 2010.
- Forecast contingent of our "**Five pillars to recovery**":
  - The U.S. real estate market must stabilize in the next 3-6 months
  - Credit conditions must continue to improve
  - Systemic risk in the global financial system (e.g. Eastern Europe) must diminish
  - Restructuring of the auto sector must continue to make progress
  - Fiscal stimulus packages must be implemented swiftly and the economic boost needs to be in the ballpark of our current expectations
- From its current level $US 0.78, the **Canadian dollar** will appreciate towards $US 0.87 by year end and $US 0.89 cents towards the end of next year.
- Most **commodity prices** will not gain any significant traction upwards before 2010. In particular, we expect **crude oil prices** to remain relatively low, reaching $US 50 (per barrel) by year-end 2010. We expect annual average crude oil prices of $US 38 this year and $46 next year. An updated detailed oil price outlook will be available on our website in upcoming weeks.
- The Federal Reserve and Bank of Canada will keep their **policy interest rates** near zero for all of 2009 and much of 2010. We expect both central banks to begin raising interest rates in the third quarter of next year, with the Fed Funds Rate reaching 1.00% and the Canadian overnight rate reaching 1.25% by year-end 2010.
- Detailed description of conditions and more complete forecasts available in March 12 QEF.

scape which will be the most reflective of severe hardship across the nation, with employment drops of around 2% for most provinces. The employment data for the first two months of the year were simply terrible, and unfortunately confirm our outlook on this front. In particular, none of Canada's four largest provinces are being spared. Both in the absolute number of jobs lost and in percentage terms, Ontario will record the largest drops.

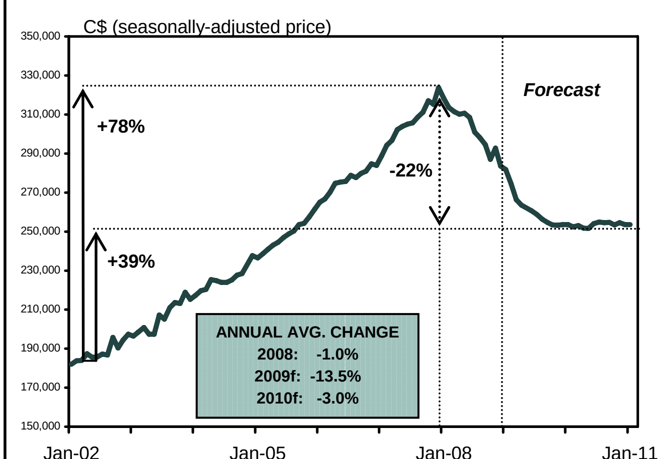
Another equalizing factor across the country comes from the fact that provincial governments, even with limited scope for significant stimulus, will lean against the recession by running deficits commensurate with lower tax revenues, which are in turn largely reflective of the downturn in their respective economies.

Extended tour

The synchronicity theme carries over into 2010. The recovery in the U.S. and world economy will be muted by a number of important lingering financial issues, not the least of which will be the continued de-leveraging of U.S. households. As a result, the Canadian economic recovery is also expected to take place at a snail's pace, with only 1.3% real GDP growth. Certainly, most provinces will experience an improvement as some of the headwinds (e.g. commodity slump) ease. Furthermore, fiscal stimulus should lift growth across the country in a fairly even fashion.

But rebounds will be modest across the board, and in most provinces, not sufficient enough to offset the declines recorded in 2009. We expect real GDP growth of roughly 1.0% for most provinces. In what is expected to still be a benign inflation environment, nominal GDP will not grow much more than that either. Behaving in typical fashion and lagging behind output and productivity as firms initially hesitate to hire, employment should also be slow out of the

NATIONAL AVERAGE EXISTING HOME PRICE



Source: CREA. Forecast by TD Economics, March. 2009

RECESSIONS PAST AND PRESENT

Production, spending, and employment are the nuts and bolts of economic indicators. Statistics Canada's Provincial Economic Accounts on income and/or spending (GDP) only go back to 1981, however. To go back a bit further in time and compare the current recession with the last two, we rely on the longer-dated and higher frequency Labour Force Survey (LFS), with the understanding that employment is a lagging indicator of economic activity. Looking at absolute employment figures can be misleading when comparing between periods where the size of the underlying population and labour force differ substantially. As such, percentage changes provide a more accurate picture as to the relative severity of different recessions. The accompanying table helps track the current recession to date to those of the early 1980s and early 1990s. Amongst others, the following observations are of note:

- The early 1980s recession was, by far, most painfully felt in B.C. and Québec, where employment plunged by 7-8%. The pain was widespread, however, as national employment fell 5.4% and nearly all provinces recorded significant drops in employment.
- The early 1990s recession was concentrated in Ontario and, to a lesser extent, Québec. In percentage terms, Ontario lost twice as many jobs (-6.6%) as Canada (-3.3%). This could only have been the case if other regions performed markedly better. Indeed, B.C. recorded an astonishing 6% increase in employment at the time and was largely unscathed by that recession.
- Given current trends and our employment forecast, the bottom line is that the current recession is not picking favourites. Unlike the experience of the last recession (early 1990s) when significant parts of the country went about their merry business, we do not believe any region will shrug this one off.

TD ECONOMICS - NATIONAL & PROVINCIAL LABOUR MARKET RECESSION TRACKER

	EMPLOYMENT			EMPLOYMENT		
	Change			Change (%)		
period	Feb-09			Current recession	Previous two recessions	
	M/M	M/M 3-m	From peak *	Q4.2008-( ) **	1990-92 ^	1981-82 ^
CANADA	**-82,600**	**-77,333**	**-295,300**	**-1.7**	**-3.3**	**-5.4**
British Columbia	**-4,900**	**-14,900**	**-46,300**	**-2.0**	**6.0**	**-8.3**
Alberta	**-23,700**	**-9,833**	**-33,100**	**-1.6**	**0.2**	**-4.2**
Saskatchewan	**600**	**733**	**2,800**	**0.5**	**-2.1**	**0.3**
Manitoba	**700**	**-433**	**1,000**	**0.2**	**-3.3**	**-3.6**
Ontario	**-35,300**	**-34,667**	**-160,100**	**-2.4**	**-6.6**	**-4.6**
Québec	**-18,400**	**-17,200**	**-50,100**	**-1.3**	**-4.1**	**-7.4**
New Brunswick	**-2,900**	**-500**	**-3,900**	**-1.1**	**0.5**	**-5.7**
Nova Scotia	**2,300**	**933**	**-1,100**	**-0.2**	**-2.6**	**-3.1**
Prince Edward Island	**300**	**-300**	**-1,100**	**-1.6**	**-0.4**	**-0.4**
Newfoundland & Labrador	**-1,200**	**-1,100**	**-3,300**	**-1.5**	**-6.2**	**-3.8**

* Cumulative net monthly change in overall employment since most recent national peak (Oct. 2008).

** Per cent change in overall employment since most recent national peak (Oct. 2008).

^ Peak to trough per cent change in last two recessions (Q3:81-Q4:82 and Q1:90-Q4:92).

Source: Statistics Canada, Labour Force Survey. Haver Analytics.

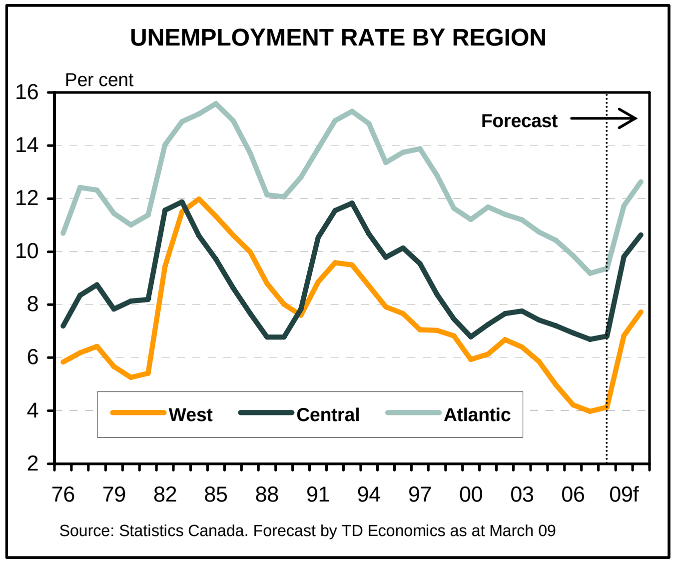
gate. On a quarterly basis, we expect aggregate net quarterly job creation, albeit modest, to start taking hold in the second quarter of 2010.

Retail volumes are expected to grow, along with a modest uptick in prices, by 3.5% in value next year, with provincial retail spending growing within a fairly narrow 3.0%-4.5% range.

Meanwhile, low mortgage rates, a slightly improved economic landscape alongside significantly better affordability will sow the seeds of a modest recovery in homes sales next year, enough to stabilize home prices by mid-2010. Given the weak handoff from this year, home prices will still be down a further 3% on average in 2010, with markets in Quebec, the Prairies, and B.C. lagging the expected stabilization elsewhere in the country.

After overbuilding in recent years in an environment of unsustainable home appreciations, homebuilders will continue to pull in the reins, having to wait for stabilization in sales and prices before significantly ramping up activity beyond 2010. An in-depth report on Canadian and regional homebuilding trends, along with a detailed outlook, will be made available on our website in the coming weeks.

With employment being a lagging indicator, the unemployment rate surges to be recorded across all provinces this year will extend into next year, by which time unemployment rates will typically be 3-4 percentage points higher than their respective 2008 average levels. The national unemployment rate will hit 10.0% by the first quarter of 2010, with that of Québec reaching 10.5% and that of Ontario reaching 11.0%. Alberta is expected to lose its crown as the province with the lowest unemployment rate, ceding this title to Saskatchewan. Nonetheless, every province west of Ontario will have nearly double their 2008 unemployment rate by the first half of next year.



While B.C. should see a modest and short-lived boost in activity surrounding the Winter Olympics, a solid and sustainable recovery for any part of country is not, in our view, the most likely scenario before 2011.

Pascal Gauthier, Economist
416-944-5730

REAL GROSS DOMESTIC PRODUCT (GDP) Annual average per cent change	82/91	2006	2007	2008E	2009F	2010F
CANADA	**-2.5**	**3.1**	**2.7**	**0.5**	**-2.4**	**1.3**
N. & L.	0.7	3.0	9.1	0.6	-2.5	1.2
P.E.I.	0.3	2.4	2.4	0.2	-2.2	1.0
N.S.	1.4	0.9	1.7	1.0	-2.0	1.1
N.B.	0.9	2.4	1.7	0.8	-1.8	0.9
Québec	-3.2	1.7	2.6	0.7	-2.3	0.9
Ontario	-3.3	2.6	2.3	-0.2	-2.7	1.2
Manitoba	-3.0	4.0	3.3	1.5	-1.2	1.3
Sask.	-0.4	-0.3	2.5	3.1	0.4	1.8
Alberta	-1.3	6.1	3.1	1.3	-2.6	1.3
B.C.	-3.0	4.4	3.0	0.8	-1.7	2.4

E: Estimate. F: Forecast by TD Economics as at March 2009

Source: Statistics Canada / Haver Analytics

NOMINAL GROSS DOMESTIC PRODUCT (GDP) Annual average per cent change	82/91	2006	2007	2008E	2009F	2010F
CANADA	**3.1**	**5.7**	**5.9**	**4.4**	**-4.5**	**1.7**
N. & L.	6.4	18.5	13.6	7.5	-6.2	1.8
P.E.I.	6.0	4.1	5.3	3.8	-4.0	1.0
N.S.	9.6	1.5	4.0	2.5	-1.5	1.2
N.B.	6.3	4.4	4.3	3.2	-2.4	1.2
Québec	3.5	3.9	5.4	2.6	-2.6	1.1
Ontario	3.0	4.3	4.5	1.9	-3.3	1.4
Manitoba	1.2	8.2	8.1	9.5	-5.6	2.0
Sask.	1.2	5.5	11.0	14.0	-5.7	2.6
Alberta	2.9	8.7	8.1	9.3	-10.0	2.3
B.C.	1.7	7.9	5.4	4.4	-3.7	2.6

E: Estimate. F: Forecast by TD Economics as at March 2009

Source: Statistics Canada / Haver Analytics

EMPLOYMENT Annual average per cent change	82/91	2006	2007	2008	2009F	2010F
CANADA	**-2.4**	**1.9**	**2.3**	**1.5**	**-2.1**	**-0.6**
N. & L.	-1.9	0.7	0.7	1.4	-2.0	-0.5
P.E.I.	-2.0	0.5	1.2	1.2	-2.3	-0.3
N.S.	-1.7	-0.3	1.3	1.2	-2.1	-0.7
N.B.	-2.6	1.4	2.1	0.9	-2.3	-0.4
Québec	-3.6	1.3	2.3	0.8	-2.0	-0.9
Ontario	-2.8	1.5	1.5	1.4	-2.6	-0.6
Manitoba	-1.6	1.2	1.6	1.7	-1.3	-0.8
Sask.	-0.2	1.7	2.1	2.2	-0.5	-0.6
Alberta	-0.5	4.8	4.7	2.7	-2.0	-0.5
B.C.	-1.9	3.1	3.2	2.1	-1.5	-0.4

F: Forecast by TD Economics as at March 2009

Source: Statistics Canada / Haver Analytics

UNEMPLOYMENT RATE Annual average, per cent	82/91	2006	2007	2008	2009F	2010F
CANADA	**10.7**	**6.3**	**6.0**	**6.1**	**9.0**	**9.9**
N. & L.	17.1	14.8	13.6	13.3	14.6	15.5
P.E.I.	14.6	11.1	10.3	10.7	12.1	13.0
N.S.	12.5	7.9	8.1	7.7	10.3	11.4
N.B.	13.4	8.7	7.6	8.6	11.6	12.3
Québec	13.1	8.0	7.2	7.3	9.4	10.3
Ontario	9.7	6.3	6.4	6.5	10.0	10.8
Manitoba	8.6	4.3	4.4	4.1	6.4	7.7
Sask.	6.8	4.6	4.2	4.1	6.3	7.6
Alberta	8.0	3.4	3.5	3.6	6.9	7.6
B.C.	11.1	4.8	4.2	4.6	7.0	7.8

F: Forecast by TD Economics as at March 2009

Source: Statistics Canada / Haver Analytics

TOTAL CONSUMER PRICE INDEX (CPI) Annual average per cent change	92-08	2007	2008	2009F	2010F
CANADA	**1.9**	**2.1**	**2.4**	**-0.8**	**0.8**
N. & L.	1.8	1.4	2.9	-0.2	1.2
P.E.I.	2.0	1.8	3.4	-0.5	1.1
N.S.	2.0	1.9	3.0	-0.5	0.7
N.B.	1.8	1.9	1.7	-1.1	1.3
Québec	1.7	1.6	2.1	-0.8	0.4
Ontario	1.9	1.8	2.3	-0.8	0.5
Manitoba	2.1	2.1	2.2	-0.6	0.9
Sask.	2.2	2.9	3.2	0.1	1.0
Alberta	2.5	4.9	3.2	-1.1	1.1
B.C.	1.8	1.7	2.1	-0.9	2.0

F: Forecast by TD Economics as at March 2009.

Source: Statistics Canada / Haver Analytics

RETAIL TRADE Annual average per cent change	1992	2007	2008	2009F	2010F
CANADA	**2.5**	**5.8**	**3.2**	**-3.0**	**3.5**
N. & L.	-0.9	9.0	7.7	-2.0	2.8
P.E.I.	6.2	7.7	4.8	-2.7	3.1
N.S.	5.4	4.2	4.5	-2.5	3.7
N.B.	4.0	5.7	4.9	-1.8	3.9
Quebec	0.3	4.6	4.9	-2.1	3.0
Ontario	2.7	3.9	3.3	-2.6	3.5
Manitoba	2.0	8.8	7.1	-2.1	4.0
Sask.	1.2	13.0	10.4	-2.5	4.2
Alberta	3.1	9.3	-0.2	-4.1	3.3
B.C.	4.7	6.7	0.2	-5.2	4.5

F: Forecast by TD Economics as at March 2009

Source: Statistics Canada / Haver Analytics

HOUSING STARTS Thousands of units					
	2006	2007	2008	2009F	2010F
CANADA	**229.1**	**227.9**	**211.4**	**125.0**	**130.0**
N. & L.	2.3	2.6	3.2	3.0	2.7
P.E.I.	0.8	0.7	0.7	0.6	0.5
N.S.	5.2	4.8	4.3	2.9	3.0
N.B.	4.0	4.1	4.2	3.4	3.0
Québec	48.0	48.7	47.9	35.0	32.0
Ontario	74.4	68.0	75.6	43.3	45.7
Manitoba	5.0	5.8	5.6	3.8	4.6
Sask.	3.7	5.9	6.8	3.0	3.5
Alberta	49.1	48.1	29.0	14.0	16.3
B.C.	36.6	39.3	34.3	16.0	18.7

F: Forecast by TD Economics as at March 2009
Source: Canada Mortgage and Housing Corporation

HOUSING STARTS Per cent change					
	2006	2007	2008	2009F	2010F
CANADA	**2.3**	**-0.5**	**-7.2**	**-40.9**	**4.0**
N. & L.	-10.7	12.7	25.2	-7.2	-10.0
P.E.I.	-15.3	-8.5	-3.5	-17.6	-5.3
N.S.	11.4	-7.8	-11.4	-32.0	3.4
N.B.	3.6	1.0	2.5	-18.6	-11.8
Québec	-5.8	1.4	-1.5	-27.0	-8.6
Ontario	-4.4	-8.6	11.2	-42.7	5.4
Manitoba	6.7	14.8	-3.8	-31.5	21.1
Sask.	12.8	58.9	14.5	-55.8	16.7
Alberta	20.9	-2.1	-39.7	-51.7	16.4
B.C.	6.0	7.4	-12.8	-53.3	16.9

F: Forecast by TD Economics as at March 2009
Source: Canada Mortgage and Housing Corporation

EXISTING HOME SALES Thousands of units					
	2006	2007	2008	2009F	2010F
CANADA	**485.3**	**523.3**	**434.0**	**320.0**	**350.0**
N. & L.	3.5	4.5	4.7	3.6	3.8
P.E.I.	1.5	1.8	1.4	1.2	1.3
N.S.	10.7	11.9	10.9	8.0	8.6
N.B.	7.1	8.2	7.6	6.0	6.3
Québec	74.3	83.5	79.4	65.0	63.5
Ontario	194.9	213.4	181.0	128.0	148.0
Manitoba	13.0	13.9	13.5	10.5	10.7
Sask.	9.1	12.1	10.2	8.5	8.4
Alberta	74.4	71.4	56.4	39.5	43.0
B.C.	96.7	102.8	68.9	49.8	56.5

F: Forecast by TD Economics as at March 2009
Source: Canadian Real Estate Association

EXISTING HOME SALES Per cent change					
	2006	2007	2008	2009F	2010F
CANADA	**-0.1**	**7.8**	**-17.1**	**-26.3**	**9.4**
N. & L.	10.2	26.4	5.0	-23.3	5.6
P.E.I.	3.0	18.6	-20.1	-18.6	8.7
N.S.	-2.3	10.8	-8.3	-26.4	7.5
N.B.	4.2	14.5	-7.4	-20.6	4.2
Québec	2.0	12.3	-4.9	-18.1	-2.3
Ontario	-1.1	9.5	-15.2	-29.3	15.6
Manitoba	2.0	7.0	-2.9	-22.4	1.9
Sask.	10.0	31.9	-15.4	-16.7	-1.2
Alberta	12.9	-3.9	-21.0	-30.0	8.9
B.C.	-9.1	6.3	-33.0	-27.8	13.6

F: Forecast by TD Economics as at March 2009
Source: Canadian Real Estate Association

AVERAGE EXISTING HOME PRICE Thousand $					
	2006	2007	2008	2009F	2010F
CANADA	**276.0**	**305.8**	**303.6**	**262.6**	**254.8**
N. & L.	139.5	149.3	178.5	185.8	183.8
P.E.I.	125.4	133.5	139.9	144.1	145.0
N.S.	168.6	181.0	189.9	187.9	190.5
N.B.	126.9	136.6	145.8	142.5	144.6
Québec	190.3	202.9	210.8	197.2	186.8
Ontario	278.4	299.5	302.4	264.0	258.8
Manitoba	150.2	169.2	190.3	181.8	170.8
Sask.	132.1	174.4	224.6	216.2	196.4
Alberta	285.4	356.2	352.9	297.3	275.7
B.C.	391.0	439.1	454.6	377.2	358.0

F: Forecast by TD Economics as at March 2009
Source: Canadian Real Estate Association

AVERAGE EXISTING HOME PRICE Per cent change					
	2006	2007	2008	2009F	2010F
CANADA	**11.2**	**10.8**	**-0.7**	**-13.5**	**-3.0**
N. & L.	-1.2	7.0	19.6	4.1	-1.1
P.E.I.	7.0	6.4	4.9	3.0	0.6
N.S.	5.9	7.3	4.9	-1.1	1.4
N.B.	5.2	7.7	6.7	-2.2	1.5
Québec	5.5	6.6	3.9	-6.4	-5.3
Ontario	5.9	7.6	0.9	-12.7	-2.0
Manitoba	12.2	12.6	12.5	-4.4	-6.1
Sask.	7.6	32.0	28.8	-3.7	-9.2
Alberta	30.8	24.8	-0.9	-15.8	-7.3
B.C.	17.7	12.3	3.5	-17.0	-5.1

F: Forecast by TD Economics as at March 2009
Source: Canadian Real Estate Association

ECONOMIC Analysis of British Columbia

volume 28 . number 7 . 2008

B.C. ECONOMIC FORECAST 2009 - 2013

Summary

The most severe financial crisis since the Great Depression is taking its toll on the real economy. Events are quickly unfolding and policy measures take time to produce results. A global economic recession is underway. Commodity prices have tumbled sharply since summer 2008 in response to falling demand and the ensuing excess supply.

In late 2008, B.C.'s economy is on the verge of recession with some sectors, such as forestry and housing, already in well-established declines. Economy-wide, job losses are appearing and unemployment is rising; consumers are not increasing their spending and businesses are cutting back capital spending plans and realigning their production capability downward to current demand levels.

During 2009, a recession unfolds in B.C.'s economy, resulting in the first drop in annual output since 1982. Employment declines in 2009 and again in 2010, although not as much, with the unemployment rate climbing to above 7%.

Declining construction, mining, and business investment, along with weak consumer spending and recessions in forestry and housing, cause an economic contraction in 2009. Higher government spending provides some offset and has more impact after 2009 when spending on infrastructure accelerates.

The 2010 Winter Olympics provide a temporary boost to economic growth, which will slip back slightly in 2011 before accelerating to almost 4% in 2013. The global economy is in a sustained recovery phase by 2011, following substantial monetary and fiscal stimulus and a return to relatively normal credit markets and risk spreads.

Forecast Summary: British Columbia

	2007	2008	2009	2010	2011	2012	2013
Real GDP, % chg.	3.0	1.3	-1.0	2.0	1.9	3.0	3.8
Nominal GDP, % chg.	5.4	5.3	-2.8	1.9	4.3	5.6	6.9
Employment, % chg.	3.2	2.2	-1.8	-0.3	1.2	2.7	3.7
Unemployment Rate, %	4.2	4.5	6.7	7.5	7.5	6.4	5.2
Population, % chg.	1.6	1.7	1.6	1.5	1.4	1.5	1.7
Housing Starts, units, 000s	39.2	33.9	16.6	17.4	23.1	25.9	31.4
Retail Sales, % chg.	6.7	1.3	-1.2	0.7	2.6	4.7	5.9
Personal Income, % chg.	6.8	4.3	-1.9	-0.4	2.8	7.0	9.1
Corporate Pre-tax profits, % chg.	-3.2	-1.2	-5.5	13.4	16.6	8.7	6.6
Consumer Price Index, % chg.	1.8	2.1	0.8	1.3	1.4	1.9	2.4

Source: Statistics Canada, Central 1 CU. Note: 2008 estimates for GDP and Income. Forecast commences 2009.

Consumer price inflation falls to less than 1% in 2009 due to the sharp decline in energy costs and lower interest rates. The broadest measure of economy-wide prices –- the GDP price deflator -- declines for the first time in a decade. Combined with the decline in economic output, this sees the economy (as measured in nominal or current dollars) shrink for the first time on record.

Total personal income will decline in 2009 and in 2010 before rising each year thereafter to 2013. The drop in total employment and hours worked, along with slower growth in wages, pulls down labour income, the largest component of personal income.

Corporate profits, before taxes, shrink in 2009, mainly due to low commodity prices and weaker domestic demand. Profitability returns in the remaining forecast years as a result of firmer commodity prices, lower labour cost pressures, and improving overall economic growth.

Overall economy

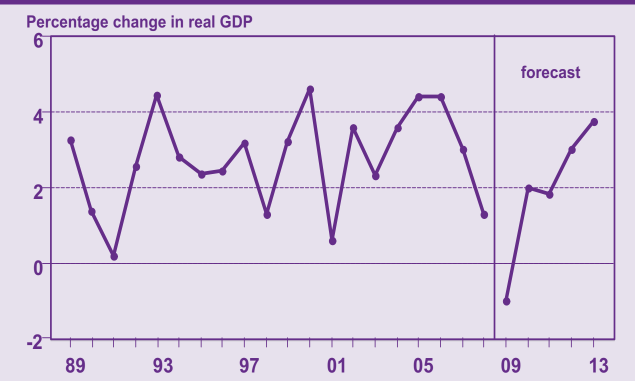
Total real Gross Domestic Product (GDP) dips 1.0% in 2009 from an estimated 1.3% growth in 2008 and 3.0% in 2007. This would be the first annual contraction in the total economy since 1982, when it shrank by 6.1%. During the global economic recession of the early 1990s, B.C.'s economy grew by 1.4% in 1990 and 0.2% in 1991.

B.C.'s economy receives a temporary boost in 2010 due to the Winter Olympics, which should bring in more than $1 billion in additional export-related spending. Real GDP is forecast to grow 2.0% in 2010 mainly on that strength, with the domestic economy expanding only 0.7%. Weakness in consumer, business investment, and residential investment spending prevails, with the only source of domestic strength coming from government spending.

After 2010, the domestic economy picks up growth momentum to reach nearly 4% in 2013, but the trade deficit widens as imports outpace exports between 2011 and 2013, the last year of this five-year forecast. Consequently, real GDP growth is forecast to be to 1.9% in 2011, 3.0% in 2012, and 3.8% in 2013.

This forecast assumes that the global monetary and fiscal policy stimulus actions yield results and begin to show a positive impact on the real economy

Economic Growth, B.C.



Source: Statistics Canada, C1CU. Note: 2008 estimate by C1CU

–- the production and consumption of good and services -– later in 2009 and more so in 2010 and beyond. Federal and provincial government fiscal stimulus packages along with further Bank of Canada rate cuts in early 2009 are built into the B.C. forecast. In addition, commodity prices begin to rise in 2010 and more robustly thereafter, in tandem with the global economic recovery.

The Canadian dollar is a key part of the forecast since it plays a large role in export and import outcomes. A general appreciation against the U.S. currency is foreseen during the next five years, which is negative for B.C. exports, positive for imports, and a slight net negative factor overall. The U.S.-Canada exchange rate is currently just above 80 cents US and is predicted to rise to 96 cents US in 2013.

Forecast risks are on the downside for 2009. There are more than the usual number of unknowns and uncertainties during this crisis, and economic forecast models are not well-equipped to handle such shock events. Forecasters, along with policy-makers, struggle to keep up with events and need to make frequent adjustments, usually downwards.

In this environment, forecast scenarios are helpful to frame an uncertain future. Should the credit markets take much longer to return to normal and the global economic recession become more severe, then B.C.'s outlook will be considerably worse. Instead of a mild recession in 2009, it could be a more substantial contraction, approaching 2% or more.

In a more positive scenario, the worst of the credit market problems end soon and the many policy measures, particularly monetary initiatives, take hold and send financial markets higher, along with confidence levels among consumers and businesses. Under this scenario, B.C. could avoid a recession in 2009 with growth between 0 and 1.0%.

Labour market

For the first time in a decade, B.C.'s economy needs fewer workers. Total employment during 2009 falls 1.8% or 42,500 persons in this forecast, followed by a slight contraction of 0.3% or 6,500 persons in 2010, marking the first consecutive annual declines in employment since 1982-83. The resumption of stronger domestic growth in 2011 to 2013 generates demand for more workers, with employment exceeding 2008 highs in 2012. Employment growth in 2012 and 2013 is forecast at 2.7% and 3.7%, respectively.

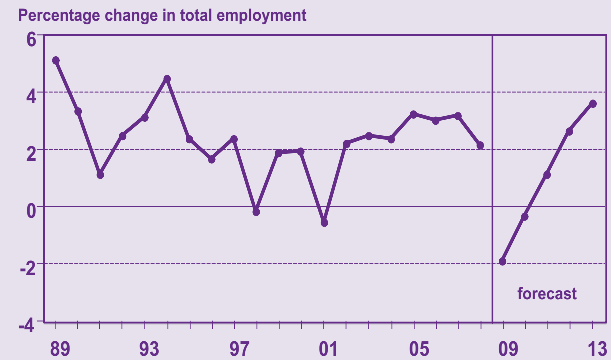
Labour force growth slows and participation rates decline during the recession since there are fewer job opportunities. This helps to limit the annual unemployment rate increase to 6.7% in 2009 and 7.5% in 2010, following an estimated 4.5% in 2008. In late 2008, B.C.'s unemployment rate rose to 5% from 4.3% in August.

Net job growth in 2011 to 2013 brings down the unemployment rate to 5.2% at the end of the forecast period. Labour force growth accelerates during this period as well, though less than growth in employment.

Job losses during an economy-wide recession are usually widespread and this generally plays out in 2009. However, job losses during this recession are mostly concentrated in the construction and the retail and wholesale trade sectors. These two industries account for 85% of total job losses, with the remaining losses spread among manufacturing, finance/insurance/real estate, professional/managerial/support, and accommodation/food services. Employment in government-related sectors post small gains during 2009.

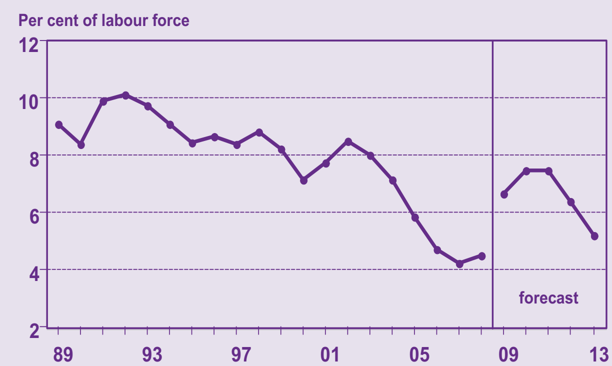
Another element in the labour market adjustment during a recession is fewer hours worked. Average weekly hours worked declines in 2009 to 32.4 hours from an estimated 33.0 hours in 2008. This trend to fewer hours was already underway during 2008, with a decline to 32.5 hours in November.

Employment Growth, B.C.



Source: Statistics Canada, C1CU. Note: 2008 estimate by C1CU

Unemployment Rate, B.C.



Source: Statistics Canada, C1CU. Note: 2008 estimate by C1CU.

The weaker labour market translates into slower wage growth during most of the forecast period. The average hourly wage rate increases 1.9% in 2009, down from 3.1% in 2008. In 2010 and 2011, even smaller wage gains will be seen, according to the forecast model used. Wages typically react with a time lag to changing labour market conditions.

Population and migration

Population growth slows from the moderate 1.7% pace set in 2008 to 1.4% in 2011. Net interprovincial migration tails off noticeably to 5,500 persons in 2009 (year ending June 30) from 11,400 persons in 2008 and then drops to 3,100 persons in 2010. Interprovincial migration flows typically drop off during an economic downturn due to diminishing job prospects.

International migration holds up well during the recession, with a slight increase to 51,100 persons on a net basis during 2009, compared to 47,600 persons in 2008. But this slips to 47,100 persons in 2011.

Prices

Another rare occurrence in 2009 is a drop in the broadest measure of economy-wide prices, the GDP price deflator. The last time it declined was 1998, with a slight 0.2% dip, whereas this forecast sees two consecutive annual declines -- 1.8% in 2009 and 0.1% in 2010. The 1982 recession and the 1990 growth recession were accompanied by high inflation rates and the increase in economic slack did not bring down prices.

This raises the spectre of deflation and recession, but in this instance the decline stems largely from a jump in import prices due to the lower Canadian dollar. Imports are subtracted from overall GDP. However, inflation in the domestic economy increases in 2009, though at a much reduced pace of 0.6% compared to 2.2% in 2008. During this recession, the increase in economic slack lessens inflation, but does not cause deflation except in residential and non-residential construction.

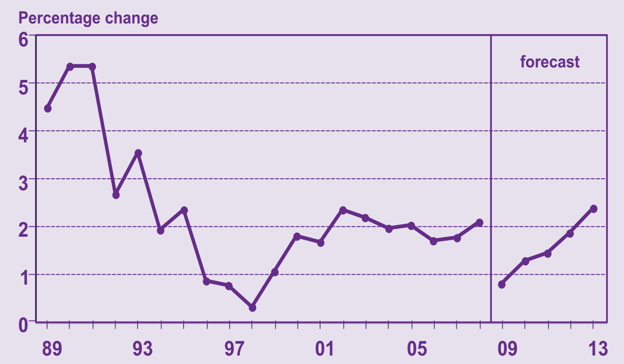
The Consumer Price Index (CPI) inflation rate slows dramatically in 2009 to 0.8% from 2.1% in 2008, on account of sharply lower energy costs. This is not the lowest CPI inflation rate on record, as 1998 saw a rise of just 0.3%. Inflation is of little concern during the forecast period, rising to 1.4% in 2011 and to 2.4% in 2013 under tighter economic conditions.

Current dollar economy

The decline in the overall GDP price index coupled with a drop in real GDP in 2009 means that nominal or current dollar GDP also declines, which has never occurred since tracking of this measure began in 1961. Current dollar GDP falls 2.8% in the 2009 forecast. The 1982 recession brought it close to an outright decline, but nominal GDP managed a 0.3% increase thanks to high underlying inflation. This time, inflation is low and not able to offset the overall decline in the real economy.

The decline in current dollar output during 2009 extends into the domestic economy and into the residential and non-residential sectors in particular. Final domestic demand falls 1.8%, led by large declines in residential and non-residential investment. Growth in current dollar GDP returns in 2010 and accelerate to 7.3% by 2013.

Consumer Price Index, B.C.



Source: Statistics Canada, C1CU. Note: 2008 estimate by C1CU.

Expenditure sectors

Domestic economy

Consumer spending, adjusted for inflation, slows sharply to 1.4% in 2009 and 0.6% in 2010, while growth in current dollar terms is 2.4% and 1.9%, respectively. For 2008, current dollar spending growth is estimated at 6.8% and at 4.9% in 2002 dollars. Consumer spending returns to more normal growth rates in 2012 and 2013 when income growth is higher. Slower consumer spending growth during 2009 to 2011 is a main factor behind the weaker domestic and overall economic performance.

Retail sales are forecast to post a rare annual decline in 2009, slipping 1.2%. This follows a weak close to 2008, with retail sales up only 1.3% after a hefty 6.7% gain in 2007. Very low consumer confidence levels, reflecting the financial crisis and heightened economic uncertainty, are a major constraint to sales growth. The outlook for the first half of 2009 is particularly bleak.

After a strong multi-year expansion, **residential investment** is in a contraction phase that lasts until 2011. The recession in this sector began in 2008, with a contraction in current dollar investment spending of 2.8% in real (2002) dollars. This deepens in 2009 to a 21.9% fall in 2002 dollars. A slight decline prevails in 2010, although there is a possibility of a small gain, and a moderate recovery takes hold in 2011 to 2013.

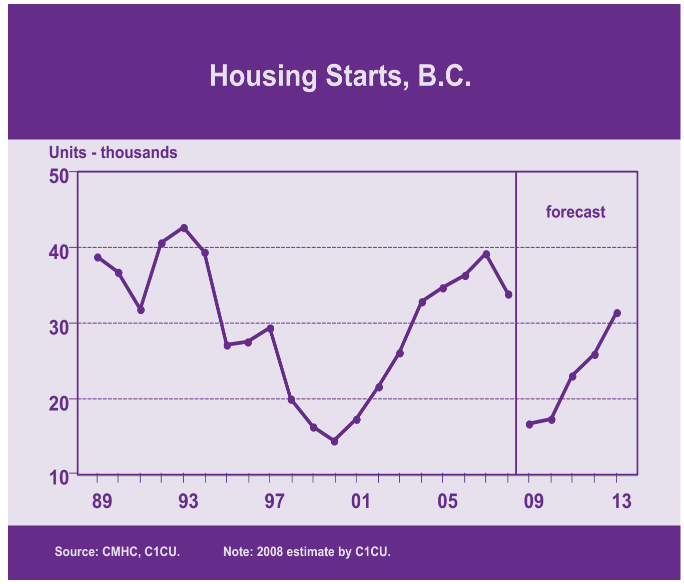
Housing starts are forecast at 16,600 units in 2009, down from an estimated 33,900 units in 2008 and more than 39,000 units in 2007. This housing recession is of major proportions (the most severe since 1982) and accounts for much of the contraction in the domestic economy and labour market during 2009.

Business investment spending on machinery-equipment and non-residential construction is another casualty of this recession. Total inflation-adjusted business investment drops 16.1% in 2009 and a further 3.2% in 2010, before climbing each year to 2013. Poor corporate profits, weak market conditions, and tighter financing contribute to the investment recession. These factors should improve in 2011 to 2013, generating investment spending gains.

Inflation-adjusted spending on machinery and equipment investment falls 12.9% in 2009 and another 5.4% in 2010. Investment spending won't return to 2008 levels until 2012 or 2013.

Non-residential construction drops by a sharp 20.7% in 2009, mainly in the engineering construction sector, as building construction is off by less than 4%. Most of the engineering construction drop is in the mining sector, owing to the reversal in market conditions and to tighter financing. Development and exploration of new mines and expansion of existing mines is postponed or curtailed during these difficult market conditions. The utilities sector is another casualty, though by a much lesser amount. Financing during this credit squeeze is a growing problem for some of the Independent Power Projects (IPP) under BC Hydro's energy plan.

Government spending accelerates in 2009 and 2010 with the new fiscal stimulus measures to deal with the economic downturn. While specific measures will be announced in the upcoming federal and provincial budgets, this forecast assumes new capital spending in the order of $3 to $3.5 billion from 2009 through 2013. Increased government spending partly replaces the private sector drop-off.



Capital investment spending rises 10% after inflation in 2009 and another 7% in each of 2010 and 2011, despite the winding down of construction of various Winter Olympic venues and related infrastructure projects in 2009. Transportation-related infrastructure projects figure prominently here during the next five years.

Spending by all governments on current goods and services grows by about 3% per year on an inflation-adjusted basis. The aging population ensures that spending on health services increases at a faster pace, while a lower growth rate in education spending prevails for demographic reasons.

Trade sector

The **trade deficit** improves in 2009 and 2010, not on the strength of exports but rather on weaker demand for imports. The real trade deficit shrinks to $20.7 billion in 2009 and $18.4 billion in 2010 from an estimated $24.0 billion in 2008. B.C.'s trade deficit hit a record 14.4% of GDP in 2008, growing from 12.4% in 2007.

Real exports fall for a third straight year in 2009 with a 1.8% decline, following an estimated 3.3% drop in 2008. The Winter Olympics boosts exports in 2010 but substantial improvement depends on improving economic conditions for the province's main trading partners, which occurs after 2010. The Canadian dollar's appreciation during this period restrains export growth, but it is accompanied by higher commodity prices and growing demand. Forest and mining exports and transportation services lead exports higher from 2011 to 2013.

Imports drop 4.8% in 2009, owing partly to fewer machinery and equipment purchases but mostly to weaker consumer and industry demand. A smaller 1.1% decline is seen in 2010, before imports turn-around and increase at a faster pace in the following three years.

Incomes

Personal income declines for the first time on record. Total personal income slips by 1.9% in 2009 and 0.4% in 2010, before rising each year thereafter, reaching 9.1% in 2013. The drop in total employment and fewer hours worked, along with slower growth in wages, pulls down labour income, the largest component of personal income. Less income from interest, dividends and investments also contribute to lower personal incomes in 2009 and 2010. Government income transfers increase 7.4% and 4.8% in those years, respectively, but this is a small component of total income.

Taking inflation into account reveals a different historical performance in personal and labour incomes. The major 1981-82 recession resulted in a larger income drop than is forecast for the 2009 recession, indicating the greater severity of that earlier recession. The 1991 economic downturn caused a small decline in real incomes.

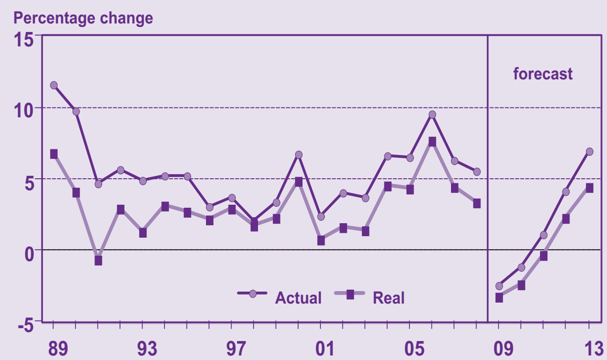
Growth of personal disposable income follows a similar time profile as personal incomes. Some new tax cuts are incorporated into the forecast as part of the fiscal stimulus packages.

Corporate profits, before taxes, mark a third consecutive year of shrinkage in 2009, mainly due to low commodity prices and weaker domestic demand. The last time that profits declined for three years in a row was 1989 to 1991, when the U.S. economy and housing market were in recession. Profitability returns in 2010 and in the remaining forecast years as a result of firmer commodity prices, lower labour cost pressures, and improving overall economic growth.

Industry performance

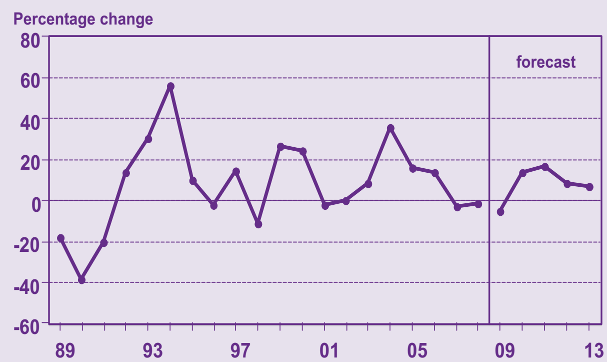
The 2009 recession has a negative effect on most industries, with construction, forestry, mining, and consumer-related sectors being hardest hit. Industries recording moderate growth in 2009 are mainly government-related sectors such as health

Labour Income Growth, B.C.



Source: Statistics Canada, C1CU. Note: 2008 estimate by C1CU, actual deflated by CPI.

Corporate Profits Before Tax, B.C.



Source: Statistics Canada, C1CU. Note: 2008 estimate by C1CU.

and education. Accommodation and food services, along with owner-occupied housing services, are among the few private sectors expanding in 2009.

The 2010 Winter Olympics significantly boosts the accommodation/food services, transportation services, and retail trade industries in that year. A more broadly based recovery plays out in the following three years, led by commodities, construction, utilities, and consumer sectors.

Forestry and related manufacturing faces another recession year in 2009, following a large 17% drop in output in 2008 and 8% in 2007. Output losses in 2009 are forecast at 7% and employment levels, and investment spending decline as well. The recession in forestry ends in 2010 assuming a U.S. housing recovery in 2010 and beyond. A moderate recovery then ensues through 2013.

Mining is undergoing a sharp reversal after a resurgence, mainly in coal, during 2008. Coal production increased with prices and demand, but the global recession is reducing demand and contract prices will tumble in 2009. Production cutbacks in 2009 and new coal mines are likely delayed until late in the forecast period.

Expansion of base and precious metals mining is on hold during the recession and not likely to materialize until prices have risen and can be expected to stay up for some time. Exploration spending declines in 2009 and probably expands after 2010. Since the last forecast report, the number of postponed mining projects postponed is up significantly.

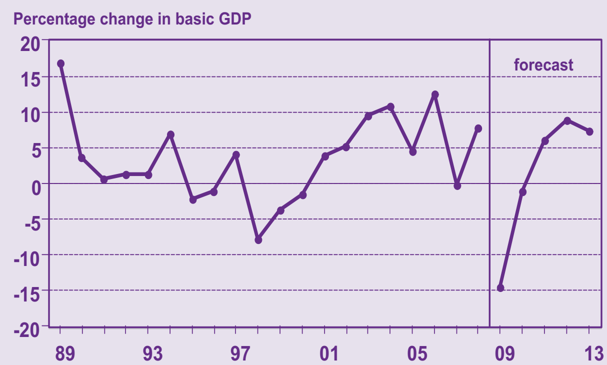
Coal and metal mining output is forecast to decline 5% in 2009 and 7% in 2010. Employment and investment spending mirror these trends.

Oil and gas production dips in 2009 despite recent record land sales and drilling activity. The more-than-50% plunge in natural gas prices cool interest in exploration and development in 2009, but the long-term outlook for this energy source is positive. B.C. has considerable potential in this sector and output grows later in the forecast period when prices recover.

Utilities output is little changed in 2009, following a 1.4% dip in 2008 and an 8.4% increase in 2007. Electricity generation was down 7% in 2008 due to lower water inflows into reservoirs, some mechanical failures and prolonged repair timelines. There is considerable potential for growth in electric power output due to BC Hydro's calls for power proposals. The current financing squeeze is delaying some capital spending in 2009, but an easing of credit problems in 2010 and beyond facilitates resurgence in IPP activity.

The **construction** industry is the hardest hit by the recession in 2009, resulting in a large 14% plunge in output and a 12% drop in employment. A sharp decline in residential construction, along with a substantial fall in engineering construction and a lesser drop in non-residential building construction, contribute to the industry's worst performance since the late 1990s. However, the economic recovery propels construction GDP to a new record high in 2013.

Construction Industry Output, B.C.



Source: Statistics Canada, C1CU. Latest actual 2007.

The **tourism** industry (composed mainly of accommodation/food, transportation, and retail activities) grows slowly in 2009. Tourism spending is discretionary and such expenditures usually contract during a recession. However, the lower Canadian dollar is a major plus for the industry in 2009, attracting more visitors. Tourism gets a strong boost from the Winter Olympics in 2010, but growth is only moderate in 2011 and 2012.

B.C.'s **TV-Film** industry is heavily reliant on U.S. demand and the lower dollar could have a fairly immediate positive impact and attract more U.S. productions in 2009. Final 2008 activity data are not yet available, but it appears to be a no-growth year.

Transportation and warehousing industry output dips in 2009 due to the recession, with both international and interprovincial exports lower and the domestic economy weaker. This industry is a beneficiary of the 2010 Winter Olympic activity. Longer-term capacity expansions are under way at B.C. ports to capture more Asia-North America trade, along with airport expansions and new energy pipelines to the coast. Investment spending in this industry is one of the main drivers of robust engineering construction activity in years ahead.

Finance, insurance, real estate and leasing, excluding owner-occupied housing, output growth declines 1% in 2009, reflecting the weaker domestic economy. Growth resumes in 2010, tracking the economy's growth rate. A GDP decline in this sector is quite rare, with only two other occurrences since 1984.

Owner-occupied housing output (imputed rental income) sees slower growth ahead, with an easing in housing prices and less new construction. This fictitious industry accounts for one-half of this sector.

Retail and wholesale trade GDP slides 0.8% in 2009 and post below-average growth in 2010 and 2011 due to weak consumer spending and personal income growth. Retail sales drop 1.2% in 2009, from a 1.3% gain in 2008 and 6.7% in 2007. A small increase appears in 2010, with larger gains seen later in the forecast. Employment in trade services drops 3% in 2009, on the heels of a 3% decline in 2008 as well.

B.C.'s recession: how long and deep?

Economic recessions do not occur frequently, since the normal state is growth, and their emergence raises the questions of depth and duration. B.C.'s recessions are typically not domestically generated and originate via exports, commodity prices, and interest rates or financial and capital market developments. Occasionally, non-economic factors, such as the oil embargoes of the 1970s, influence the recession phase of the business cycle.

B.C. economy has undergone four recessions since 1961, compared to six for Canada as a whole and the U.S. B.C.'s recessions have been short and mild except for the severe 1981-82 recession, when real GDP dropped 7.4% from peak to trough in the five quarters ending with Q4 of 1982. The average length of a B.C. recession has been less than one year, with the longest being 1981-82 at five quarters. However, fiscal stimulus temporarily boosted GDP growth in 1983, although the economy later fell back. Had that stimulus not occurred, the recession would have lasted longer.

Labour market performance during recessions usually entails losses of 2% to 3% in total employment, though in the 1981-82 recession it fell more than 7% and the unemployment rate increased by more than eight percentage points.

Post-war recessions in Canada and the U.S. last about 10 to 11 months on average, but since the current U.S. recession began in January 2008, according to the National Bureau of Economic Research, it will be longer than average. Canada's business cycle dates for the current episode are not yet set, though it is likely to involve a peak in the third quarter of 2008 and a recession thereafter.

The beginning of B.C.'s recession was probably the fourth quarter of 2008 or the first quarter of 2009 at the latest. Timely GDP data are not available (the latest is for 2007), so analysts rely on other indicators such as employment, trade, retail sales, construction activity, traveler, and transportation data. Using these data, Central 1's BC Coincident Economic Index for October 2008 does not yet display a downturn.

External economic forecast

The most severe financial crisis since the Great Depression is spreading into the real economy with greater effect each month. The strong linkages between the financial system and the real economy ensure that, when the flow of financing is constrained and more costly, it is only a matter of time before the production and consumption of goods and services is negatively affected. Policymakers recognize the severity of the crisis by undertaking aggressive actions to help the economy.

Events are quickly unfolding and policy measures take time to produce results. In the meantime, the economy enters a recession phase that lasts for most of 2009. The recession's low point is still ahead and the economic fallout is accelerating. Declining production and company cutbacks, more layoffs and rising unemployment, higher unsold inventories and price reductions, falling consumer and business confidence, and postponed or cancelled investment and spending plans play out for several more months.

Research into the relationship between a banking crisis and the economy generally concludes that an economic downturn is more severe and protracted when accompanied by a banking crisis, highlighting the important link between finance and economic activity. This implies that the unfolding recession could be longer and deeper than generally expected and forecasters may be underestimating its severity.

The global economy is in a recession, pulled down by the industrialized economies of North America, Europe, Japan, Australia, and others. The fast-growing developing or emerging economies of China, India, Brazil, Russia, south-east Asia and others are following their export markets and fall into a comparatively slow-growth phase in 2009.

Economic recovery emerges slowly in 2010 and gain momentum each year through to 2013. This is the conventional view and it is incorporated into the B.C. forecast, but the global economy could take longer to recover and the recession could be deeper.

The sharp decline in energy prices in the second half of 2008 offers relief to users but hurts producers. Accurately predicting oil prices by year in this environment is difficult and the fallback position is to use recent futures market prices. The futures market is in a state of contango (where distant futures prices exceed current spot prices) with oil prices up to $US 75 per barrel by the end of 2013. Natural gas futures prices (per million BTU) are forecast to rise to $US 7.50 after 2010.

The U.S.-Canada exchange rate forecast calls for gradual appreciation following the sharp decline in September and October 2008. The currency averages about $US 0.83 in 2009 and rises to $US 0.96 in 2013, mainly driven by higher commodity prices combined with US dollar weakness.

Interest rates fall to new lows in 2009 and rise to normal levels by 2013 once the economic recovery takes hold. The Bank of Canada is expected to cut its policy rate to new lows in early 2009 and government bond yields fall to record lows during this flight to safety and capital preservation. However, the cost of raising funds in the market for lenders and businesses is forecast to stay high in 2009, constraining the flow of financing and economic activity. The cost of funds begin to decline when risk premiums come down and credit markets return to normal.

Commodity prices are generally expected to rise during the forecast period, which is positive for B.C.'s forestry, mining and energy sectors. In 2009, though, prices mostly remain low and are not expected to turn higher until more signs of economic recovery emerge. The expected appreciation in the Canadian dollar limits revenue gains for exporters.

Key External Economic Forecasts

	2007	2008	2009	2010	2011	2012	2013
U.S. Real GDP, % chg.	2.2	1.2	-1.7	1.6	2.0	2.5	3.0
Japan Real GDP, % chg.	2.1	0.4	-1.3	1.0	1.5	1.7	1.9
European Union Real GDP, % chg.	2.6	1.2	-1.2	1.3	1.6	1.8	2.2
China Real GDP, % chg.	11.9	9.0	7.0	8.5	9.5	10.0	10.0
Canada Real GDP, % chg.	2.6	0.4	-1.2	1.5	2.2	3.0	3.3
Canada 3-month T-Bill, %	4.14	2.40	0.65	1.50	2.50	3.25	4.00
Canada 10-year GoC Bond, %	4.27	3.60	2.60	3.30	4.00	5.00	6.00
U.S.-Canada Exchange Rate	93.0	94.3	82.6	87.7	90.1	92.6	96.2
Wood Product Industry Price Index, %chg.	-3.3	-4.2	8.5	-2.1	2.2	0.8	1.8
Pulp and Paper Industry Price Index, %chg.	-0.9	6.3	9.5	-2.8	0.4	2.2	3.6
Crude Oil, US$ per barrel	72	100	50	65	70	72	75
Natural Gas, US$ per MBTU	6.86	8.8	6.5	7.5	7.5	7.5	7.5
Coal Price per tonne,% chg.	-21.0	92.1	-42.9	0.9	13.6	11.2	8.3

Source: Statistics Canada, Central 1 CU, U.S. BEA, Japan SNA, IMF, NYMEX, B.C. Ministry of Energy & Mines.
Note: Yearly averages. Forecast commences 2009.

Gross Domestic Expenditures ($ Millions): British Columbia

	2007	2008	2009	2010	2011	2012	2013
Consumer	120,066	128,171	131,185	133,636	136,121	141,096	148,686
% change	7.0	6.8	2.4	1.9	1.9	3.7	5.4
Government Current	33,911	35,078	36,439	38,195	40,076	42,215	44,597
% change	3.7	3.4	3.9	4.8	4.9	5.3	5.6
Government Investment	6,455	6,344	6,982	7,328	7,826	8,336	8,849
% change	15.2	-1.7	10.1	5.0	6.8	6.5	6.2
Residential Construction	19,095	18,973	14,390	14,230	15,644	16,886	19,467
% change	10.7	-0.6	-24.2	-1.1	9.9	7.9	15.3
Plant and Equipment	21,886	24,755	20,487	19,958	21,451	24,955	27,498
% change	2.2	13.1	-17.2	-2.6	7.5	16.3	10.2
Machinery & Equipment	10,974	11,105	9,869	9,334	9,728	10,689	11,251
% change	5.7	1.2	-11.1	-5.4	4.2	9.9	5.3
Non-Res. Construction	10,912	13,651	10,618	10,624	11,723	14,266	16,246
% change	-1.1	25.1	-22.2	0.1	10.3	21.7	13.9
Domestic Demand	201,413	213,321	209,483	213,347	221,119	233,489	249,097
% change	6.5	5.9	-1.8	1.8	3.6	5.6	6.7
Exports	78,933	79,032	78,849	82,238	84,706	87,156	90,944
% change	-0.1	0.1	-0.2	4.3	3.0	2.9	4.3
Imports	89,562	91,275	92,245	95,446	97,440	100,847	105,444
% change	3.5	1.9	1.1	3.5	2.1	3.5	4.6
Net Exports	-10,629	-12,243	-13,396	-13,208	-12,734	-13,691	-14,500
Inventory Change	1,606	1,521	764	390	704	1,109	1,476
Statistical Discrepancy	-137	-137	-137	-137	-137	-137	-137
GDE	192,527	202,737	196,988	200,666	209,226	221,043	236,211
% change	5.4	5.3	-2.8	1.9	4.3	5.6	6.9

Source: Statistics Canada and Central 1 CU forecast.

Gross Domestic Expenditures ($2002 Millions): British Columbia							
	2007	2008	2009	2010	2011	2012	2013
Consumer	111,521	116,939	118,630	119,335	119,903	122,146	125,850
% change	5.2	4.9	1.4	0.6	0.5	1.9	3.0
Government Current	30,905	31,271	31,839	32,666	33,500	34,385	35,345
% change	4.1	1.2	1.8	2.6	2.6	2.6	2.8
Government Investment	5,435	5,024	5,542	5,997	6,378	6,161	6,145
% change	8.8	-7.6	10.3	8.2	6.4	-3.4	-0.3
Residential Construction	13,432	13,055	10,201	10,016	10,855	11,431	12,638
% change	2.2	-2.8	-21.9	-1.8	8.4	5.3	10.6
Plant and Equipment	21,553	23,276	19,527	18,896	20,247	23,330	25,229
% change	2.4	8.0	-16.1	-3.2	7.2	15.2	8.1
Machinery & Equipment	13,318	13,619	11,865	11,222	11,931	13,509	14,507
% change	8.8	2.3	-12.9	-5.4	6.3	13.2	7.4
Non-Res.Construction	8,235	9,656	7,662	7,674	8,316	9,822	10,722
% change	-6.4	17.3	-20.7	0.2	8.4	18.1	9.2
Domestic Demand	182,330	188,992	184,439	185,800	189,958	196,397	204,222
% change	4.4	3.7	-2.4	0.7	2.2	3.4	4.0
Exports	72,638	70,216	68,963	70,330	72,512	74,526	77,451
% change	-0.3	-3.3	-1.8	2.0	3.1	2.8	3.9
Imports	93,015	94,254	89,690	88,695	92,152	95,654	99,945
% change	3.9	1.3	-4.8	-1.1	3.9	3.8	4.5
Net Exports	-20,377	-24,038	-20,727	-18,365	-19,640	-21,128	-22,494
Inventory Change	1,813	964	555	128	339	516	692
Statistcial Discrepancy	117	117	117	117	117	117	117
GDE	164,583	166,745	165,059	168,348	171,468	176,622	183,288
% change	3.0	1.3	-1.0	2.0	1.9	3.0	3.8

Source: Statistics Canada and Central 1 CU forecast.

B.C. Consumer Expenditures	2007	2008	2009	2010	2011	2012	2013
$ Millions							
Consumer Expenditures	120,066	128,171	131,185	133,636	136,121	141,096	148,686
% change	7.0	6.8	2.4	1.9	1.9	3.7	5.4
Durable Goods	14,546	14,611	14,258	14,389	14,534	14,941	15,809
% change	6.8	0.4	-2.4	0.9	1.0	2.8	5.8
Semi-Durable Goods	9,043	9,799	10,118	10,341	10,519	10,893	11,513
% change	6.4	8.4	3.3	2.2	1.7	3.6	5.7
Non-Durable Goods	25,825	27,924	28,328	28,918	29,635	30,879	32,630
% change	4.9	8.1	1.4	2.1	2.5	4.2	5.7
Services	70,652	75,837	78,482	79,988	81,434	84,384	88,735
% change	7.9	7.3	3.5	1.9	1.8	3.6	5.2
Retail Sales	56,365	57,112	56,444	56,843	58,317	61,052	64,641
% change	6.7	1.3	-1.2	0.7	2.6	4.7	5.9
$ 2002 Millions							
Consumer Expenditures	111,521	116,939	118,630	119,335	119,903	122,146	125,850
% change	5.2	4.9	1.4	0.6	0.5	1.9	3.0
Durable Goods	15,314	16,312	16,078	16,386	16,878	17,701	18,738
% change	8.0	6.5	-1.4	1.9	3.0	4.9	5.9
Semi-Durable Goods	9,156	10,119	10,417	10,648	10,855	11,264	11,902
% change	7.5	10.5	2.9	2.2	2.0	3.8	5.7
Non-Durable Goods	22,458	23,253	23,826	24,081	24,189	24,459	24,957
% change	2.8	3.5	2.5	1.1	0.4	1.1	2.0
Services	64,819	67,613	68,580	68,567	68,464	69,408	71,192
% change	5.3	4.3	1.4	0.0	-0.1	1.4	2.6

Source: Statistics Canada and Central 1 CU forecast.

B.C. Residential Investment and Housing Starts

	2007	2008	2009	2010	2011	2012	2013
$ Millions							
Total Residential Investment	19,095	18,973	14,390	14,230	15,644	16,886	19,467
% change	10.7	-0.6	-24.2	-1.1	9.9	7.9	15.3
New Dwellings	10,346	9,133	4,352	4,579	6,172	7,107	8,986
% change	0.7	-19.8	-71.8	6.3	47.4	18.2	32.7
Renovations	6,692	7,437	7,506	7,264	7,183	7,437	7,993
% change	14.9	11.1	0.9	-3.2	-1.1	3.5	7.5
Total Acquisition Costs	1,903	2,237	2,369	2,225	2,126	2,171	2,304
% change	6.3	17.6	5.9	-6.1	-4.5	2.1	6.1
Other Residential Construction	154	165	163	162	164	171	184
% change	17.3	7.4	-1.1	-0.8	1.1	4.2	7.7
$ 2002 Millions							
Total Residential Investment	13,432	13,055	10,201	10,016	10,855	11,431	12,638
% change	2.2	-2.8	-21.9	-1.8	8.4	5.3	10.6
New Dwellings	7,278	6,284	3,085	3,223	4,282	4,811	5,834
% change	0.5	-13.7	-50.9	4.5	32.9	12.4	21.3
Renovations	4,707	5,117	5,321	5,113	4,983	5,035	5,189
% change	6.1	8.7	4.0	-3.9	-2.5	1.0	3.1
Total Acquisition Costs	1,338	1,539	1,679	1,566	1,475	1,470	1,496
% change	-1.8	15.0	9.1	-6.7	-5.8	-0.4	1.8
Other Residential Construction	108	114	116	114	114	116	119
% change	8.3	5.1	1.9	-1.6	-0.3	1.7	3.2
Housing Starts, Units	39,195	33,852	16,619	17,362	23,071	25,920	31,417
% change	7.6	-13.6	-50.9	4.5	32.9	12.3	21.2

Source: Statistics Canada and Central 1 CU forecast.

Real Non-residential Construction Investment: British Columbia

$ 2002 Millions	2007	2008	2009	2010	2011	2012	2013
Engineering Construction	7,207	8,398	6,881	6,946	7,490	8,947	9,750
% change	-7.3	16.5	-18.1	0.9	7.8	19.4	9.0
Building Construction	4,620	4,578	4,409	4,400	4,618	4,778	4,940
% change	5.4	-0.9	-3.7	-0.2	5.0	3.5	3.4
Commercial	1,715	1,730	1,501	1,461	1,505	1,540	1,544
% change	11.5	0.9	-13.2	-2.7	3.0	2.4	0.3
Industrial	930	1,062	876	822	921	1,038	1,145
% change	-2.9	14.2	-17.5	-6.1	12.0	12.8	10.3
Institutional-Government	1,975	1,786	2,033	2,117	2,193	2,199	2,250
% change	4.7	-9.6	13.8	4.2	3.6	0.3	2.3
Total non-residential Construction	11,827	12,976	11,291	11,346	12,109	13,724	14,690
% change	-2.7	9.7	-13.0	0.5	6.7	13.3	7.0

Source: Statistics Canada and Central 1 CU forecast.

GDP by Industry ($2002 Millions): British Columbia	2007	2008	2009	2010	2011	2012	2013
Total	150,412	152,388	150,848	153,853	156,705	161,415	167,507
% change	2.7	1.3	-1.0	2.0	1.9	3.0	3.8
Agriculture	1,175	1,148	1,139	1,161	1,189	1,218	1,261
% change	3.8	-2.3	-0.8	1.9	2.4	2.4	3.5
Forestry & Logging	3,277	2,679	2,456	2,486	2,630	2,784	3,005
% change	-8.0	-18.3	-8.3	1.2	5.8	5.9	7.9
Oil & Gas Mining	3,301	3,315	3,273	3,288	3,319	3,363	3,411
% change	-0.4	0.4	-1.3	0.4	0.9	1.3	1.4
Other Mining	1,228	1,265	1,205	1,125	1,170	1,161	1,351
% change	-1.9	3.0	-4.7	-6.7	4.0	-0.8	16.4
Fish, Hunting & Trapping	130	126	124	123	123	127	131
% change	-14.1	-2.8	-1.6	-0.9	0.5	2.6	3.3
Manufacturing	15,592	14,503	14,108	14,647	15,394	15,846	16,558
% change	-2.3	-7.0	-2.7	3.8	5.1	2.9	4.5
Wood Products	4,341	3,516	3,209	3,319	3,522	3,746	4,079
% change	-10.4	-19.0	-8.7	3.4	6.1	6.4	8.9
Pulp & Paper Products	1,540	1,397	1,382	1,413	1,452	1,461	1,481
% change	-2.2	-9.3	-1.1	2.3	2.7	0.6	1.4
Other Manufacturing	9,632	9,513	9,440	9,837	10,342	10,560	10,917
% change	1.7	-1.2	-0.8	4.2	5.1	2.1	3.4
Utilities	3,316	3,271	3,271	3,345	3,447	3,634	3,903
% change	8.4	-1.4	0.0	2.3	3.1	5.4	7.4
Construction	8,996	9,701	8,295	8,210	8,702	9,476	10,165
% change	-0.3	7.8	-14.5	-1.0	6.0	8.9	7.3
Transportation & Warehousing	9,691	9,833	9,788	10,028	10,037	10,323	10,638
% change	2.6	1.5	-0.5	2.5	0.1	2.8	3.1
Retail & Wholesale Trade	17,962	18,553	18,409	18,719	19,062	19,694	20,477
% change	7.7	3.3	-0.8	1.7	1.8	3.3	4.0
FIREL*	34,521	35,834	36,328	36,969	37,584	38,496	39,682
% change	4.5	3.8	1.4	1.8	1.7	2.4	3.1
Owner-Occupied Housing	16,419	17,348	18,045	18,372	18,712	19,173	19,694
% change	4.6	5.7	4.0	1.8	1.9	2.5	2.7
Other FIREL*	18,102	18,486	18,284	18,597	18,872	19,323	19,988
% change	4.4	2.1	-1.1	1.7	1.5	2.4	3.4
Information, Professional, Scientific, Managerial	15,833	16,071	15,933	16,210	16,525	16,957	17,482
% change	4.3	1.5	-0.9	1.7	1.9	2.6	3.1
Other Services	6,400	6,559	6,565	6,722	6,615	6,763	6,963
% change	3.7	2.5	0.1	2.4	-1.6	2.2	3.0
Accomodation & Food Services	4,572	4,655	4,722	5,116	4,720	4,804	5,039
% change	2.2	1.8	1.4	8.3	-7.8	1.8	4.9
Education Services	7,744	7,865	7,892	7,921	8,012	8,103	8,202
% change	3.7	1.6	0.3	0.4	1.2	1.1	1.2
Health & Social Services	9,560	9,843	10,072	10,290	10,499	10,784	11,139
% change	1.9	3.0	2.3	2.2	2.0	2.7	3.3
Government Services	7,560	7,619	7,712	7,943	8,137	8,354	8,597
% change	3.3	0.8	1.2	3.0	2.4	2.7	2.9

*Source: Statistics Canada and Central 1 CU forecast. *FIREL - Finannce, insurance, real estate and leasing*

Employment by Industry (000s): British Columbia							
	2007	2008	2009	2010	2011	2012	2013
Total	2,266	2,316	2,274	2,267	2,294	2,355	2,441
% change	3.2	2.2	-1.8	-0.3	1.2	2.7	3.7
Agriculture	36	34	34	33	34	35	37
% change	4.3	-5.5	-0.1	-2.3	1.9	4.3	4.2
Other Primary	47	45	41	39	40	41	43
% change	8.0	-4.8	-8.9	-5.1	1.6	4.2	5.4
Manufacturing	205	187	183	180	187	190	199
% change	3.8	-8.7	-2.2	-1.9	3.8	2.0	4.5
Utilities	10	14	15	16	16	18	19
% change	19.8	38.3	5.8	5.4	1.6	10.4	4.6
Construction	197	220	194	182	187	195	207
% change	9.8	11.9	-11.9	-6.2	2.9	3.8	6.6
Transportation & Warehousing	126	128	126	125	126	132	138
% change	5.1	2.2	-1.6	-0.9	0.8	4.8	4.1
Trade	365	355	343	350	353	360	372
% change	3.2	-2.9	-3.1	1.9	1.0	1.9	3.3
FIREL*	145	147	144	142	143	149	155
% change	5.1	1.6	-2.0	-1.8	1.1	4.1	4.0
Professional, Scientific, Managerial	383	396	391	387	394	406	421
% change	0.8	3.4	-1.1	-1.2	1.8	3.1	3.7
Accomodation & Food Services	173	177	177	183	176	181	189
% change	1.3	2.6	-0.3	3.9	-3.9	2.8	4.0
Education Services	156	162	165	165	166	166	167
% change	0.1	3.6	1.7	0.5	0.6	0.0	0.7
Health & Welfare Services	240	246	254	258	262	268	275
% change	3.2	2.4	3.4	1.6	1.5	2.2	2.7
Other Services	88	102	101	100	99	103	107
% change	-3.1	15.6	-0.9	-1.3	-0.1	4.0	3.6
Government Services	96	103	105	107	109	109	112
% change	5.0	7.5	1.6	2.3	1.8	0.2	2.3

Source: Statistics Canada and Central 1 CU forecast. ** FIREL - Finance, insurance, real estate and leasing*

B.C. Labour Market Indicators							
	2007	2008	2009	2010	2011	2012	2013
Source Population, 000s	3,571	3,642	3,708	3,770	3,832	3,896	3,965
% change	1.7	2.0	1.8	1.7	1.6	1.7	1.8
Participation Rate %	66.3	66.6	65.7	65.0	64.7	64.6	64.9
Labour Force, 000s	2,366	2,426	2,436	2,451	2,480	2,516	2,575
% change	2.7	2.5	0.4	0.6	1.2	1.5	2.4
Employment, 000s	2,266	2,316	2,274	2,267	2,294	2,355	2,441
% change	3.2	2.2	-1.8	-0.3	1.2	2.7	3.7
Unemployment,000s	100.1	110.1	162.4	183.6	186	160.8	133.8
Unemployment Rate %	4.2	4.5	6.7	7.5	7.5	6.4	5.2
Average Weekly Hours	33.6	33	32.4	32.4	32.5	32.8	33.1
% change	1.2	-1.7	-1.9	0.0	0.2	0.9	1.0
Average Hour Wage Rate % chg.	2.1	3.1	1.9	0.3	-0.3	0.6	2.1
Unit Labour Costs % change	1.4	-0.3	-1.7	-0.1	-1.1	-0.8	0.1

Source: Statistics Canada and Central 1 CU forecast.

B.C. Income Components ($ Millions)

	2007	2008	2009	2010	2011	2012	2013
Personal Income	151,836	158,367	155,335	154,742	159,009	170,157	185,570
% change	6.8	4.3	-1.9	-0.4	2.8	7.0	9.1
Labour Income	99,894	105,424	102,875	101,713	102,865	107,168	114,586
% change	6.3	5.5	-2.4	-1.1	1.1	4.2	6.9
Interest, Dividends, & Investment	18,804	18,221	16,499	15,602	16,918	21,863	27,767
% change	10.5	-3.1	-9.4	-5.4	8.4	29.2	27.0
Government Transfers	19,234	20,029	21,514	22,547	23,468	24,228	25,120
% change	7.0	4.1	7.4	4.8	4.1	3.2	3.7
Unincorporated Business	14,336	15,130	14,827	15,222	16,080	17,221	18,451
% change	5.1	5.5	-2.0	2.7	5.6	7.1	7.1
Other Transfers	703	761	789	814	846	894	949
% change	5.4	8.2	3.8	3.1	4.0	5.6	6.2
Disposable Income	117,363	122,502	120,632	120,688	124,608	133,581	145,813
% change	6.5	4.4	-1.5	0.0	3.2	7.2	9.2
Taxes & Contributions	34,473	35,864	34,703	34,054	34,401	36,576	39,758
% change	7.8	4.0	-3.2	-1.9	1.0	6.3	8.7
Corporate Profits Before Tax	21,384	21,135	19,977	22,661	26,423	28,729	30,632
% change	-3.2	-1.2	-5.5	13.4	16.6	8.7	6.6

Source: Statistics Canada and Central 1 CU forecast.

Population Components: British Columbia

	2007	2008	2009	2010	2011	2012	2013
Population, 000s	4,310.3	4,381.5	4,450.4	4,515.3	4,580.7	4,650.9	4,729.0
% change	1.6	1.7	1.6	1.5	1.4	1.5	1.7
Births, 000s	42.3	44.0	44.2	44.9	45.5	45.8	46.2
Deaths, 000s	30.9	32.5	32.0	33.0	33.9	34.9	35.9
Natural Increase, 000s	11.5	11.5	12.3	11.9	11.5	10.9	10.4
Net Migration, 000s	55.3	59.1	56.6	52.9	53.9	59.3	67.7
Net International, 000s	40.3	47.6	51.1	49.8	47.1	49.5	53.2
Net Interprovincial, 000s	15.0	11.4	5.5	3.1	6.8	9.8	14.4

Source: Statistics Canada and Central 1 CU forecast. As of Ju;y 1st.

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Central 1

Appendix E

CAPITAL EXPENDITURES

Category A Capital Historical Information

Referenced in 2010 2011 Revenue Requirements Application, Part III, Section B, Tab 1 – page 182

Table 1 - Comparison of Interior Mains Activity by Region for 2003 & 2008

Interior Mains Activity (metres) 2003 vs 2008			
Region	**2,003**	**2,008**	**Change**
Northern	2,713	8,017	5,304
Thompson	681	20,640	19,959
North Okanagan	8,722	33,216	24,494
Central Okanagan	20,997	17,997	-3,000
South Okanagan	3,416	6,770	3,354
West Kootenays	368	12,925	12,557
East Kootenays	2,060	11,705	9,645
Total	**38,957**	**111,270**	**72,313**

Referenced in 2010 2011 Revenue Requirements Application, Part III, Section B, Tab 1 – page 186

Table 2 - Comparison of Service Header Mains Activity by Region for 2003 and 2008

Region	**2003**	**2008**	**Change**
Lower Mainland West	7,061	3083	(3,978)
Lower Mainland East	9,952	17850	7,898
Northern	376	863	487
Thompson	1,051	5460	4,409
North Okanagan	918	6668	5,750
Central Okanagan	7,265	9681	2,416
South Okanagan	1,544	1073	(471)
West Kootenays	272	952	680
East Kootenays	272	1211	939
Total	**28,711**	**46,841**	**18,130**

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April 3, 2009

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") 2008 Year End Reports for:
- **TGI-TGVI Main Extension Report in Compliance with British Columbia Utilities Commission (the "Commission") Order No. G-152-07; and**
- **TGI Vertical Subdivision Report in Compliance with Commission Order No. G-6-08**

On July 31, 2007 TGI and TGVI (collectively the "Companies") applied to the Commission for changes to the System Extension and Customer Connection Policies ("TGI-TGVI System Extension and Customer Connection Policies Review"). On December 6, 2007, the Commission issued Order No. G-152-07 and Reasons for Decision approving changes to the TGI-TGVI System Extension and Customer Connection Policies Review changes. In Commission Order No. G-152-07 (page 37), the Companies were directed to file with the Commission a Main Extension report:

"within 90 days of calendar year end, a Main Extension Report including the following:
- *a review of a random sampling of MX test results representing a confidence interval of +/-12 percent at a 95 percent confidence level and the five highest cost main extensions to determine if the aggregate PI thresholds need to be adjusted on a go forward basis in order to achieve the aggregate PI of 1.1. The review is to include a comparison of forecast and actual costs; consumption; and PI for the first five years of main extensions in the sample;*
- *a concise explanation of the random sampling methodology used; and*
- *a comparison of the forecast and actual cost for all service line and main extension installations."*

On November 2, 2007, TGI applied for approval of a change to the General Terms and Conditions of its Tariff to allow an alternative method of providing gas service to Vertical Subdivision developments ("Vertical Subdivisions"). On January 10, 2008, the Commission issued Order No. G-6-08 approving TGI's application, and specified the inclusion of TGI Vertical Subdivisions in the Main Extension report:

> *"Terasen is directed include, in the Main Extension Report that Terasen was directed to file in the Commission's Main Extension Decision, the results of TGI's main extension tests to Vertical Subdivisions."*

Pursuant to Commission Order No. G-152-07 and Commission Order No. G-6-08, the Companies respectfully submit the following as the 2008 TGI and TGVI Year End Main Extension and TGI Vertical Subdivision reports.

We trust that the Commission will find the reports in order. If there are any questions, please contact Ian Miki at 604-592-7903.

Yours very truly,

TERASEN GAS INC.
TERASEN GAS (VANCOUVER ISLAND) INC.

Original signed:

Tom A. Loski

Attachments

cc(e-mail only): Registered Parties to the:

- TGI Multi-Year PBR Settlement and Annual Reviews
- TGVI Negotiated Settlement and Settlement Updates

Terasen Gas Inc. and
Terasen Gas (Vancouver Island) Inc.
Main Extension Report

and

Terasen Gas Inc.
Vertical Subdivision Report

for

2008 Year End

April 3, 2009

Part A - 2008 Year End TGI and TGVI Main Extension Report

We respectfully submit the TGI and TGVI Main Extension 2008 Year End Report.

The report demonstrates that on a portfolio basis, the main extensions installed in 2008 are economical and do not harm existing customers because the average actual PI is 1.2, higher than the threshold of 1.1. Therefore, no change is required to the aggregate PI threshold of 1.1. The results also demonstrate that for a significant majority of mains the current estimating methodology is producing good overall results and is appropriate for a large percentage of main extensions. We believe this report satisfies the Commission's requirements and also demonstrates our commitment to improvement and prudently processing main extension applications.

The report is presented below.

Background

On July 31, 2007, TGI and TGVI (collectively the "Companies") applied to the Commission for changes to the System Extension and Customer Connection Policies ("TGI-TGVI System Extension and Customer Connection Policies Review"). On December 6, 2007, the Commission issued Order No. G-152-07 and Reasons for Decision approving changes to the TGI-TGVI System Extension and Customer Connection Policies Review. In Commission Order No. G-152-07 (page 37), the Companies were directed to file with the Commission a Main Extension ("MX") report:

> *"within 90 days of calendar year end, a Main Extension Report including the following:*
> - *a review of a random sampling of MX test results representing a confidence interval of +/-12 percent at a 95 percent confidence level and the five highest cost main extensions to determine if the aggregate PI thresholds need to be adjusted on a go forward basis in order to achieve the aggregate PI of 1.1. The review is to include a comparison of forecast and actual costs; consumption; and PI for the first five years of main extensions in the sample;*
> - *a concise explanation of the random sampling methodology used; and*
> - *a comparison of the forecast and actual cost for all service line and main extension installations."*

TGI and TGVI Main Extension Test

The results presented in this report demonstrate that the overall or portfolio based assessment of main extensions is appropriate. For the 2008 main extensions, the average actual PI is 1.2, higher than the threshold of 1.1. Therefore, no change is required to the aggregate PI threshold of 1.1. An average actual PI higher than the threshold means that from a portfolio view, the main extensions are economical and not harming existing customers. When reviewing main extension costs on a portfolio basis, the results demonstrate that for a significant majority of mains, the current estimating methodology is producing good results. However, we have also identified areas of improvements to the cost estimating process. Based on these results, we believe the portfolio based model of assessing main extensions makes sense and is appropriate.

The TGI and TGVI MX Test is a twenty year discounted cash flow analysis which compares the present value ("PV") of cash inflows to the PV of the cash outflows for 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 recovery charge or the midstream cost recovery charge. The cash outflows are the estimated costs for TGI and TGVI to build and operate the system in the first five years of the main extension 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 PI that represents a ratio of the PV of expected revenues to the PV of expected costs. If the PI is 0.8 or greater then the system extension can proceed without the need for a customer contribution. If the PI is less than 0.8, a customer contribution would be required to make up the shortfall in order that the system extension can be built without negative economic impact to existing customers. The Commission has also approved a portfolio based or aggregate PI of 1.1 as a threshold for all main extensions completed on an annual basis.

Total Data Set and Random Sampling Methodology

For the purposes of this report, the total data set for the 2008 main extensions was determined based on the following three criteria:

1. All MX Tests undertaken in 2008;
2. All main segments within the MX Test are installed in 2008; and
3. All completed main segments are "Technically Completed" by October 31, 2008.

Referring to criteria #2, larger main extensions such as subdivisions are typically comprised of more than one main segment. Therefore, to assess the total cost of the main extension it is the Companies' view that all main segments included in the MX test must be installed in order to be included in the data set required for the report.

Referring to criteria #3, it is our view that all complete main segments must also be "Technically Complete" (or "TECO") by October 31, 2008. TECO is an internal job tracking status which confirms that the paperwork associated with the installation has been received from the field crew and entered into the job tracking system. The October 31, 2008 criteria is based on the Companies' policy of waiting 60 days after TECO to allow for a reasonable amount of time to capture outstanding costs and invoices prior to confirming the actual cost of the installation at the end of December 31, 2008. Those main extensions and segments which do not meet the criteria will be excluded from the total data set and evaluated for the preparation of next year's report.

It is noted that one significant TGVI main extension was not included in this report. The Shawnigan Lake Road main extension (8.5 km long, 114mm Distribution Pressure) was not included in the total data set because the installation commenced in summer 2008 but was not completed until early 2009. The Shawnigan Lake Road main extension is referenced again in the sub-section titled "Variance Review". This main extension will be included and evaluated in next year's report.

Based on the above criteria, the total data set includes 439 main extensions. 282 of those were installed for TGI and the remaining 157 were installed for TGVI. To obtain a random sample with a confidence interval of +/-12 percent (at a 95 percent confidence level), a sample size of 58 is required. This was determined through the use of a "Sample Size Calculator" which is available online through the Neag School of Education at the University of Conneticut (http://www.gifted.uconn.edu/siegle/research/Samples/samplecalculator.htm). To determine an appropriate sample size, one simply inputs the population size (439) along with the required confidence interval (+/-12 percent), and the sample size is then calculated (58). To draw a random sample of 58 main extensions from the population size of 439, SAS (a statistical analysis system) was used. By loading the 439 main extension notification numbers (an identification number) into SAS, a random sample of 58 was drawn.

Analysis

Forecast versus Actual Costs

A review of forecast versus actual costs for mains installed during 2008 has not only indicated the current estimation process is reasonable, but has also helped identify opportunities to further enhance the process, ultimately leading to an even greater level of accuracy when estimating main installation costs in the future. The following tables and graph illustrate:

- the average forecast and actual costs for all mains installed during 2008;
- the average forecast and actual costs for a random sample taken from all mains installed during 2008;
- the distribution of cost variances (forecast versus actual) for all mains installed during 2008; and
- the PI for all mains installed during 2008.

All mains installed in 2008:

MAINS (Total Data Set of 439)			
	Forecast Costs	**Actual Costs**	**% Difference**
TGI	4,509,905	$5,532,275	18%
TGVI	$2,429,162	$2,901,345	16%
Totals	**$6,939,068**	**$8,433,620**	18%

Overall, the variance between forecast and actual costs for both Companies is 18%, and there is no material difference between the variances seen for TGI and TGVI. A discussion of the variance is presented in the sub-section below titled "Variance Review".

Random sample of mains installed in 2008:

MAINS (Random Sample of 58)			
	Forecast Costs	**Actual Costs**	**% Difference**
TGI	$352,046	$438,861	20%
TGVI	$264,194	$300,613	12%
Totals	**$616,239**	**$739,475**	17%

Overall, the variance between forecast and actual costs when analyzing a random sample of all mains installed during 2008 is in line with that of the total data set. The portion of the random sample related to TGVI mains installed shows a slightly lower variance, which when considering the overall variance for TGVI is attributed to sampling variability.

Profitability Index:

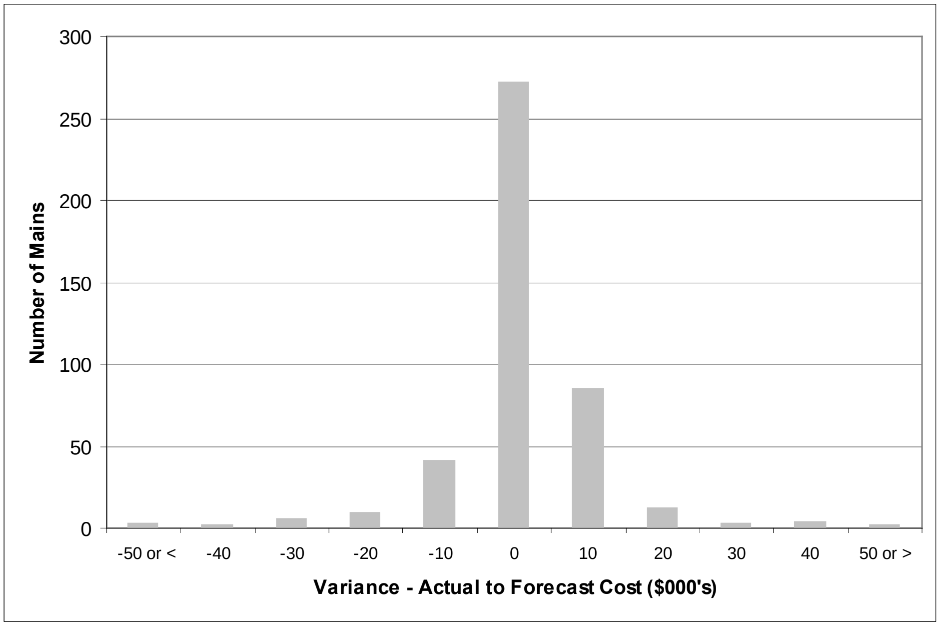
As discussed earlier, the PI indicates the ratio of cash inflows to outflows (on a net present value basis). The following table illustrates the average PI calculated at the time the estimate was created ("Average Forecast PI"), and also the average PI calculated by replacing the forecast costs with actual costs ("Average Actual PI"). Note that "Average Actual PI" is still an estimate, as the consumption figures are still estimates.

Company	Average Forecast PI	Average Actual PI
TGI	1.3	1.2
TGVI	1.6	1.4
Combined	**1.4**	**1.2**

On a portfolio basis, the Average Actual PI is 1.2 and is higher than the aggregate PI threshold of 1.1. Therefore, no change is required to the aggregate PI threshold of 1.1. The Average Actual PI includes actual costs which are approximately 18% higher than forecast. An Average Actual PI of 1.2 means that the main extensions economical and are not having a negative impact on existing customers. The results also supports our view that the current process for estimating main installation costs is reasonable as it is producing positive economic results on an overall basis.

Variance Review

For all of the mains in the total data set, the forecast cost was determined using a geographically based unit-length or "geo-code" methodology. As presented above, the geo-code methodology resulted in an 18% variance between forecast and actual costs for both Companies. One reason for the variance is increasing labour, paving and material rates in 2008. A cost variance distribution of the mains installed in 2008 is presented below:



The histogram illustrates the dollar variance between the actual and forecast costs of all 2008 main extensions. Further analysis was conducted to assess the impact of unfavourable variances. By excluding the top 10% of mains (44 mains) that had unfavourable variances (actual costs exceed forecast costs), the average variance was seen to decrease from 18% to 4%. This means that for 90% of the mains (395 mains), the average variance is a modest 4%, while the Average Actual PI for the portfolio portion of 395 mains is 1.4, as compared to an overall value of 1.2. Therefore, on a portfolio basis, we conclude that the geo-price methodology is producing good overall results and is appropriate for the vast majority of main extensions.

However, we recognize the need for improvements to the cost estimating process therefore, a detailed variance review was performed on the mains which were identified as having an unfavourable variance from the above histogram. The objective of the detailed variance review was to identify opportunities to refine the estimation process in order to achieve a greater level of accuracy. The review process revealed that approximately 10% of all main extensions installed in 2008 had similar characteristics, both site specific and unique that explain, at least in part, the variance between actual and forecast costs. Therefore, we believe the geo-code methodology is not the most appropriate estimating method for this small portion of main extensions. By examining the site specific characteristics, we have developed a set of criteria for determining whether or not a particular main installation will follow the geo-code methodology or a more detailed estimation process. The detailed estimation criteria are:

1) Main length exceeds 1,000 meters

2) Initial estimate (through existing process) exceeds $100,000

3) Non-standard requirements exist. These include situations such as bridge crossings, highway crossings, directional drillings, crossing fish bearing watercourses, or where archeological permits are required.

For main installations that fit into the any of the above criteria, the Companies have developed and implemented additional controls and management oversight in the main installation process. This includes an increase to the number of sight visits to confirm requirements, a more detailed estimate process, and also a more formal review process. The Companies anticipate that the detailed estimating process will reduce the variance between the forecast and actual cost for those applicable mains and will also reduce the overall variance for those mains included in the data set.

As referenced earlier in the report, the Shawnigan Lake Road main extension was not included in the total data set but contributed to the detailed variance review. The reason for inclusion in the review is because in the fall of 2008 management was informed that the actual costs would significantly exceed the forecast cost. In an effort to proactively manage the unfavourable variance, a detailed review of the main extension was immediately initiated and a project manager was assigned to oversee the completion of the installation. The detailed review identified opportunities for several process improvements and contributed to the development of the detailed estimation criteria above. The Shawnigan Lake Road main extension will be included and evaluated in next year's report.

Highest Cost Main Extensions

As part of the annual main extension review process, a more formal review of the high cost main installations has been conducted. The geo-code methodology was used to determine the forecast cost for the all of the main extensions including the five highest cost main extensions. The 2008 main extensions for TGI and TGVI are presented below:

TGI 2008 HIGHEST COST MAINS									
Name	Location	Actual Length (m)	Total Forecasted Attachments	Projected Attachments (Year 1)	Installed Attachments (YTD)	TECO Date	Forecasted P.I.	Forecasted Costs	Actual Costs
Trans-Canada Hwy	Savona	13873	511	135	0	2008-09-12	0.9	$950,140	$833,569
Juniper Rd	Naramata	1866	44	10	0	2008-07-22	1.7	$24,141	$119,211
Crystal Creek Dr	Anmore	791	22	22	2	2008-10-21	1.0	$30,876	$115,364
163 & 61A Ave	Surrey	2786	171	50	23	2008-04-23	1.4	$77,032	$114,145
Rio Dr	Kelowna	2312	92	40	0	2008-09-15	0.7	$90,674	$112,712

TGVI 2008 HIGHEST COST MAINS									
Name	Location	Actual Length (m)	Total Forecasted Attachments	Projected Attachments (Year 1)	Installed Attachments (YTD)	TECO Date	Forecasted P.I.	Forecasted Costs	Actual Costs
Players Dr	Langford	1901	74	74	0	2008-05-23	1.5	$237,392	$219,888
French Rd	Sooke	1324	50	50	6	2008-04-07	1.2	$68,993	$159,929
Hutchinson Rd	Cobble Hill	1523	75	41	5	2008-04-07	1.4	$81,857	$86,812
Sewell Rd	Colwood	1083	25	10	15	2008-04-07	1.0	$45,187	$83,822
Phillips Rd	Sooke	652	87	86	0	2008-10-20	0.9	$196,787	$75,997

A review of the above main extensions confirms that nine of the ten mains extensions fit at least one of the detailed estimation criteria presented above. This means the detailed estimating process would have been applied to all but one of the above main installations.

The detailed estimating process would allow for adequate consideration of the site specific conditions. Therefore, it is expected that the forecast costs would have been significantly closer to the actual costs if the more detailed estimating process had been applied. The effect would result in an overall reduction in the variance for those mains included in the total data set.

The following two paragraphs describe the primary reasons for the significant cost variances, by company.

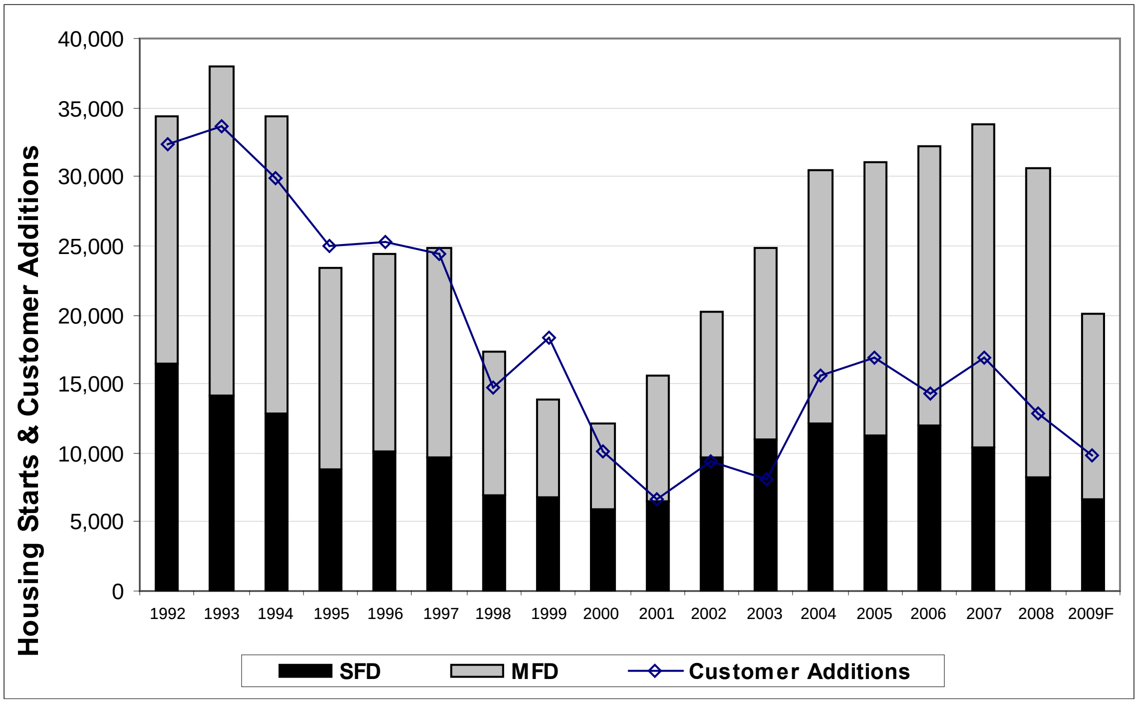
For TGI, the top five costing main installations with significant variances have explanations that are reasonable. There were unexpected ground conditions which included rocky terrain, increases in road grade, and also unexpected paving activity. Difficulties locating foreign underground utilities also contributed to the variances. These unexpected situations resulted in additional costs for labour, repair & restoration, backfill & compaction, and road base materials.

For TGVI, the top five costing main installations with significant variances have explanations that are also reasonable. Unforeseen rock, increased asphalt removal, increased road restoration costs, and re-staking due to revised land base plans all contributed towards these variances. In one case (Phillips Rd, Sooke) the main was only 50% completed as it was put on hold by the developer.

As discussed above, nine of the ten top costing main installations in 2008 would have been estimated using the more detailed approach. And, given the variance explanations above, the more detailed approach would have resulted in a greater level of accuracy in the forecast costs. The expected result would be an overall reduction in the variance for those mains included in the total data set.

Attachments and Consumption

In the MX Test, the total forecast customer attachments and the forecast customer attachments from Year 1 to Year 5 are determined through discussions with the developers. Actual customer attachments do not occur until after the main installation and typically occur over a period of time as homes and businesses become ready for gas service. For the 2008 main extensions, a full year has not passed which means a comparison of forecast to actual year one attachments is not valid at this time. However, some comments are presented based on the results available to date. Referring to the five highest cost mains for TGI and TGVI, the mains which were installed or TECO in the first half of the 2008 had, in general, lower than forecast attachments. An explanation is at the time the main extension test was processed (early 2008), the builders and developers were optimistic and forecasted high home construction volumes to continue. However, signs of a weakening economy became evident in mid-2008 and as a result the attachment rate for the latter part of 2008 continued to decrease significantly. Similarly, for those mains installed late in 2008, the actual attachments were significantly lower than forecast due to the slowing economy and significantly lower home building levels. It is anticipated that Year 1 attachment values will be available for next year’s report. The graph below reveals the declining number housing starts and customer attachments (for TGI and TGVI combined) in the past 2 years:



For the 2008 main extensions, as attachments occurred throughout the year, annualized consumption is not realized during the first year of attachment. In Year 2 of an attachment, normalized annualized consumption is generally realized. It is anticipated that one year of normalized, annualized consumption values will be available for next year's report.

Profitability Index

As presented earlier in the report, the average forecast and average "actual" PI (based on average actual costs) for each Company is greater than the aggregate annual PI of 1.1. The aggregate PI looks at the main extensions on a portfolio or overall basis.

Company	Average Forecast PI
TGI	1.3
TGVI	1.6
Combined	**1.4**

Since actual year one attachments and normalized, annualized consumption is unavailable, MX Tests incorporating those year one actual attachments and consumption values can not be performed for this report. It is anticipated that one year of attachment and consumption values will be available for next year's report. In next year's report, the Companies propose to re-evaluate the MX Tests using average actual values for: attachments, consumption, service line costs and main costs. The results will provide a comparison between the forecast and actual PI for the random sample and 5 highest cost main extensions.

MX Test Updates

Parameter Update

The MX Test contains a wide variety of parameters of which some are common to all rate classes while others are rate class specific. The common parameters for both TGI and TGVI are:

- Service Line Installation Fee
- Application Fee - New Installation
- Account Transfer Fee
- Overhead Rate
- CCA Class 1
- Discount Rate
- System Improvement
- Income Tax Rate & Surcharge
- Property Tax Rate
- Working Capital

The parameters specific to rate classes for both TGI and TGVI are:

- O&M per Customer
- 1% in Lieu Rate
- Basic Charge
- Delivery Charge

The parameters above are reviewed annually and updated as appropriate in January 2009.

Geo-Code Update

As described in the TGI-TGVI System Extension and Customer Connection Policies Review, the cost of main extensions and service lines are forecast based on data from the prior year and adjusted, when necessary, to reflect anticipated changes in either inflation or operating policies.

Though the costing models for main extensions and service lines had remained unchanged for several years, forecast versus actual costs were reviewed periodically by operations personnel. The review has resulted in the need to make minor adjustments to the costing models.

Service Lines

The service line costing model is a tool used to estimate the cost of new service lines. On an annual basis, the Companies assess the methodology used to determine service line cost parameters for the costing model and implement any resulting changes early the following year. For 2009, the service line costing model was updated using a linear regression (or best fit line) methodology which was used for the prior update based on 2008 historical costs. For 2009, the methodology was adjusted to appropriately reflect the cost of mobilizing/demobilizing a crew to the installation. This adjustment resulted in a flatter slope or lower unit length cost which translated into a lower average cost for longer service lines and a higher average cost for shorter service lines. Data on direct costs of service lines for 2008 was extracted from the Companies' financial information system. The data set was then analyzed on a geographical basis, which represent the various operating regions within the TGI and TGVI service territories ("zones"). Updated parameters were then developed for each zone and inflated by 2.5% to reflect potential increases in both internal and external costs associated with service line installations. Based on these values, the forecast cost of a typical 17 meter service line has slightly increased to approximately $1,185 on average across TGI's service territory. Likewise the average cost in TGVI's service territory has decreased to $1,228 primarily as a result of an adjustment to the linear regression (best fit line) methodology to establishing an appropriate service line cost. The improvement include an increase in the "fixed" charge to more appropriately reflect the current cost of mobilizing/demobilizing a TGVI crew to an installation and a corresponding decrease to the unit length installation charge to provide a best fit line through the service line data. For TGVI service lines greater than 7 meters, the average service line cost will be lower than the previous year. These are compared to the forecast costs that would result from the values prior to the update.

Average Service Line Costs 17m Service		
	2009	**2008**
TGI	$1,185	$1,184
TGVI	$1,228	$1,407

Main Extensions

The forecast costing model was also updated for main extensions. Consistent with the service line analysis, data was extracted from the same source and analyzed on a geographical basis. Only data from 2008 main extensions was used which was then adjusted for inflation to arrive at the pricing model for 2009. The updated 2009 main extension geo-codes or geographically based unit-length price show increases greater than the patterns found with the service line pricing.

Main Extension Geo Codes ($/m)	**2009**	**2008**
TGI Weighted Average	$37.59	$35.65
TGVI Weighted Average	$61.35	$50.07

The geo-codes above are reviewed annually and were updated in January 2009.

<u>Cost Estimating Improvements</u>

The current process for pricing or determining the forecast cost of service lines and main extensions is based on a geographically based unit-length price or "geo-code" methodology. As part of the annual geo-code review process, the Companies determined that for a small percentage of service and main installations (approximately 10%), the geo-code methodology is not the most appropriate estimating method due to unique, site specific requirements. Examples of site specific requirements are: long or high cost mains (greater than 1,000 meters or construction costs greater than $100,000), highway/bridge crossings, directional drillings, crossing fish bearing watercourses, archaeological permits, etc. For these types of installations the Companies have implemented a new detailed estimating process to improve the accuracy of the forecast cost. The new process includes: the development of criteria to identify main extensions which require detailed estimating, increased site visits to confirm site requirements, and management review of the cost estimate. In addition, the Companies have also implemented additional controls and management oversight in the main installation process to monitor and manage the actual costs. The process improvements were implemented in early 2009 and the results will be continuously monitored.

Conclusion

The report demonstrates that on a portfolio basis, the main extensions installed in 2008 are economical and do not harm existing customers because the average actual PI is 1.2, higher than the threshold of 1.1. Therefore, no change is required to the aggregate PI threshold of 1.1. The results also demonstrate that for a significant majority of mains, the geo-price methodology is producing good overall results and is appropriate for a large percentage of main extensions. However, we have identified the need to apply a detailed cost estimating methodology (to approximately 10% of main extensions) to address unique and site specific conditions that are not adequately addressed by the geo-code methodology. We have implemented the detailed cost estimating process improvements and are committed to monitoring the results. We expect the overall results to reveal forecast costs which are closer to actual costs which in turn will increase the Average Actual PI. We believe the 2008 TGI and TGVI Main Extension Report satisfies the Commission's requirements and also demonstrates our commitment to improvements and prudently processing main extension applications.

Part B – 2008 Year End TGI Vertical Subdivision Report

We respectfully submit the TGI Vertical Subdivision ("VSD") 2008 Year End Report.

The report demonstrates that on a portfolio basis, the VSDs installed between 2003 and 2008 are highly economical and do not harm existing customers because the average actual PI is 1.8 and is significantly higher than the aggregate PI threshold of 1.1. Therefore, no change is required to the aggregate PI threshold of 1.1. On a portfolio basis, the variance between actual versus forecast cost is low which demonstrates that our cost estimating methodology is producing good overall results. In addition, we have continued to refine our forecast consumption methodology to achieve a forecast consumption which is closer to actual consumption. We believe this report satisfies Commission's requirements and also demonstrates our commitment to improvement and prudently processing VSDs.

Background

Commission Order No. G-6-08 specified the inclusion of TGI Vertical Subdivisions in the Main Extension report:

> *"Terasen is directed include, in the Main Extension Report that Terasen was directed to file in the Commission's Main Extension Decision, the results of TGI's main extension tests to Vertical Subdivisions."*

The 2008 TGI VSD report is presented below.

Main Extension Test

The Main Extension Test is used to assess the economic viability of each VSD.

Data

For the purposes of this report, the data set for the VSDs was based on the following criteria which is similar to the criteria used for the main extensions:

1. All VSDs completed and installed after the 3rd quarter of 2003; and
2. All completed VSDs are Technically Complete by October 31, 2008.

Referring to criteria #1, the necessary customer information is only available beginning from the 3rd quarter of 2003.

Referring to criteria #2, it is our view that all completed VSDs must also be "Technically Complete" (or "TECO") by October 31, 2008. TECO is an internal job tracking status which confirms that the paperwork associated with the installation has been received from the field crew and entered into the job tracking system. The October 31, 2008 criteria is based on the Company's policy of waiting 60 days after TECO to allow for a reasonable amount of time to capture outstanding costs and invoices prior to confirming the actual cost of the installation at the end of December 31, 2008. Those VSDs which do not meet the criteria will be excluded from the data set and evaluated for the preparation of next year's report.

Based on the above criteria, the data set for this report includes 76 VSDs and includes all those completed from 2003 to 2008. Of the 76 VSDs, there are 25 located in the Interior region, while the remaining 51 are located within the Lower Mainland region.

Analysis

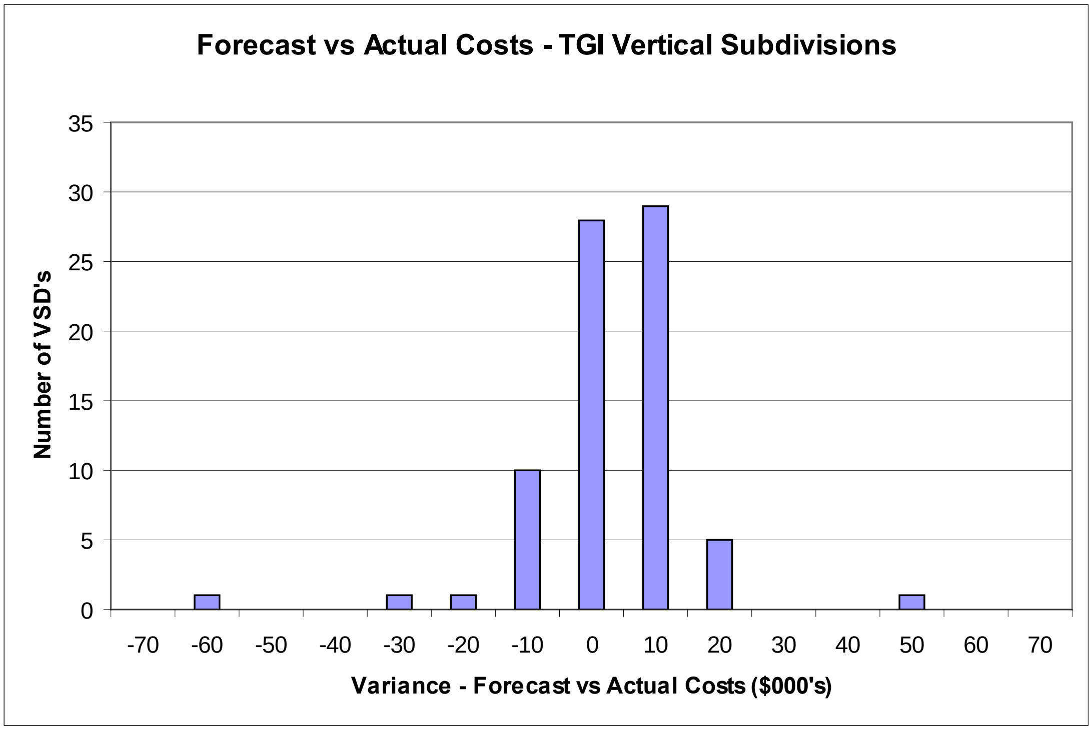
Forecast versus Actual Costs

The forecast cost for each VSD is determined using a detailed estimating methodology. For the data set, the variance between the forecast and actual costs is 5% as presented below:

TGI Vertical Subdivisions (Total data set of 76)		
Forecast Costs	**Actual Costs**	**% Difference**
$2,752,746	$2,887,040	5%

Based on this result we believe the detailed estimating methodology is producing good overall results and is appropriate for VSDs.

A review of the cost variances for each individual VSD project was undertaken, to identify any opportunities for improvement to the current estimating process. As seen in the following histogram, the distribution of cost variances for the individual VSD projects is relatively normal.



The histogram illustrates the dollar variance between the actual and forecast costs of the 2003 to 2008 VSDs. Further analysis was conducted to assess the impact of unfavourable variances (actual costs exceeded forecast costs). By excluding 5% of the VSD's (4 VSDs) that had the highest unfavourable variances, the average actual variance was seen to decrease from 5% to approximately 1%. This means that for 95% of the VSDs (72 VSD's), the variance is approximately 1% while the Average Actual PI (which is described below) for the portfolio portion of 72 VSD's is 2.0 as compared to an overall value of 1.8. Therefore, on a portfolio basis the detailed estimating methodology is producing good overall results and is appropriate for VSDs.

For VSDS, the increase in actual costs is primarily attributed to building design changes and field changes which occurred after the gas design was completed. We will continue to work with developers and their designers during the gas design phase to estimate a forecast cost which are closer to actual cost.

Attachments and Consumption

In the MX Test, the total forecast customer attachments and the forecast customer attachments from Year 1 to Year 5 are determined through discussions with the developers. For VSDs, the number of units or premises is determined in the design process. Unlike main extensions, all (in most cases 100%, the exception is due to design changes during building construction) of the forecast customer attachments are observed in Year 1, specifically after the header (gas main in the building) and meter installations and once the building is completed and deemed ready for occupancy.

For the data set, the actual consumption is approximately 60% lower than the forecast consumption. The primary reason for this variance was the use of, what has proven to be, optimistic forecast consumption values. Not withstanding this consumption forecasting variance, on a portfolio basis the average actual PI is 1.8 and is significantly higher than the aggregate PI threshold of 1.1 as presented in the next section. From 2003 to 2008, we gained a greater understanding of the VSD market and consumer behaviour. For example, we have observed that some occupants are not full time or year round consumers because the units have been purchased by non-residents or for investment purposes. To address the variance between the forecast and actual consumption, we have gradually made improvements to the forecast consumption methodology between 2003 to 2008 as described below:

- 2003 - The forecast consumption for each premise was determined assuming standard residential annual consumption values (per appliance).

- 2004 - The residential consumption values were adjusted downwards as a result of the "2002 Residential End Use Study (2004)".

- 2007 - It was recognized that the forecast consumption values were still optimistic. Therefore process improvements were implemented such that each VSD project was assessed individually and the forecast consumption values were adjusted appropriately (downwards) to more accurately reflect actual consumption.

- 2008 - As per Commission Order G-6-08, the MX Test inputs were updated to reflect that larger developments, such as VSDs, often require several months before all units are occupied and normal consumption patterns established. To explain further, as units become occupied throughout the year, annualized consumption is not realized during the first year of attachment. In Year 2 of an attachment, normalized annualized consumption is generally realized.

The following table presents a history of the revised appliance loads:

Forecast Appliance Loads (GJ/year)			
Appliance	**2003**	**2004**	**2008**
Water Heater	33.5	20.7	Individually estimated
Fireplace	30.0	15.7	Individually estimated
Range	9.5	8.4	Individually estimated
Dryer	6.5	3.9	Individually estimated

A Residential End Use Study is currently underway with results expected in latter half of this year. The results of the study will identify whether changes to the forecast appliance loads are required.

It is expected that the improvements to the consumption forecasting methodology implemented since 2007 will result in lower variances. We will continue to monitor customer consumption behaviour and will revise the consumption forecast methodology as necessary to ensure that consumption forecasts are closer to actual consumption.

Profitability Index

The Average Forecast and Average Actual PI (based on average actual costs, average actual attachments and average actual consumption) is presented below:

TGI Vertical Subdivisions (Total data set of 76 VSDs)	
Average Forecast PI	**Average Actual PI**
2.4	1.8

On a portfolio basis, the average actual PI is 1.8 and is significantly higher than the aggregate PI threshold of 1.1. Therefore, no change is required to the aggregate PI threshold of 1.1. The variance between the Average Forecast PI and the Average Actual PI is due to the actual consumption values being lower than what was forecast. However, even when incorporating the actual costs, available actual consumption and attachments, the results still indicate that on a portfolio basis, the VSDs are highly economical and do not harm existing customers.

MX Test Updates

Parameter Update

The MX Test contains a wide variety of parameters of which some are common to all rate classes while others are rate class specific. The common parameters for both TGI and TGVI are:

- Service Line Installation Fee
- Application Fee - New Installation
- Account Transfer Fee
- Overhead Rate
- CCA Class 1
- Discount Rate
- System Improvement
- Income Tax Rate & Surcharge
- Property Tax Rate
- Working Capital

The parameters specific to rate classes for both TGI and TGVI are:

- O&M per Customer
- 1% in Lieu Rate
- Basic Charge
- Delivery Charge

The parameters above are reviewed annually and updated as appropriate in January 2009.

Conclusion

The report demonstrates that on a portfolio basis, the VSDs installed between 2003 and 2008 are highly economical and do not harm existing customers because the average actual PI is 1.8 and is significantly higher than the aggregate PI threshold of 1.1. Therefore, no change is required to the aggregate PI threshold of 1.1. On a portfolio basis, the actual cost versus forecast cost had a low variance of 5% which demonstrates that our cost estimating methodology is producing good overall results. In addition, the results also demonstrate that for 95% of the VSDs, the detailed estimating methodology is producing very good overall results and is appropriate for a large percentage of the VSDs. We will continue to work with developers and their designers during the gas design phase to estimate forecast costs which are closer to actual costs. We have continued to refine our forecast consumption methodology to achieve a forecast consumption which is closer to actual consumption. We are committed to further understanding customer consumption behaviour and will update the consumption forecast methodology appropriately once the results of the Residential End Use Study become available later this year. We believe this report satisfies Commission's requirements and also demonstrates our commitment to improvement and prudently processing VSDs.

Appendix F

OPERATIONS AND MAINTENANCE EXPENDITURES

OPERATING & MAINTENANCE EXPENSE HISTORY

a) Operating & Maintenance Expense Resource View 2003- 2008

TERASEN GAS INC
OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
($000)

Line No.	Particulars		2003	2004	2005	2006	2007	2008
	(1)		(2)	(3)	(4)	(5)	(6)	(7)
1	M&E Costs		$ 36,478	$ 32,751	$ 30,927	$ 36,995	$ 41,161	$ 38,581
2	COPE Costs		22,378	22,557	23,109	22,382	21,966	23,046
3	IBEW Costs		20,125	19,824	20,399	18,559	19,926	21,201
4								
5	**Labour Costs**		**78,981**	**75,133**	**74,435**	**77,936**	**83,053**	**82,827**
6								
7	Vehicle Costs		3,775	4,783	4,889	4,226	4,748	5,001
8	Employee Expenses		3,208	2,901	3,194	3,378	3,498	4,422
9	Materials and Supplies		4,083	4,536	4,533	4,223	4,436	5,891
10	Computer Costs		8,991	7,693	7,265	8,086	7,489	7,391
11	Fees and Administration Costs		21,746	24,106	27,163	33,884	25,246	27,976
12	Contractor Costs		49,539	53,173	53,885	52,298	53,640	55,593
13	Facilities	*	10,285	9,679	9,859	10,012	10,921	10,792
14	Recoveries & Revenue		(12,622)	(10,290)	(14,392)	(14,836)	(14,058)	(14,155)
15								
16	**Non-Labour Costs**		**89,005**	**96,581**	**96,396**	**101,270**	**95,919**	**102,912**
17								
18								
19	**Total Gross O&M Expenses**		**167,985**	**171,714**	**170,831**	**179,206**	**178,973**	**185,739**
20								
21	Less: Coastal Lease	*		-	-	-	-	-
22	Less: Vehicle Lease Reclass		(1,918)	(1,900)	(1,911)	(1,872)	(2,008)	(1,988)
23	Less: Capitalized Overhead		(25,104)	(25,892)	(26,212)	(27,111)	(27,401)	(27,566)
24								
25	**Total O&M Expenses**		**$ 140,963**	**$ 143,922**	**$ 142,708**	**$ 150,223**	**$ 149,564**	**$ 156,186**

Notes:

*The 2004 Annual Report subtracted the Coastal Lease after Gross O&M total. For comparable reporting to 2003 the lease cost has been taken out of Facilities line 500-10.

b) *Operating & Maintenance Expense- Activity View 2003-2008*

TERASEN GAS INC
OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
($000)

Line No.	Particulars	Reference	2003	2004	2005	2006	2007	2008
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Distribution Supervision	100-11	$ 9,976	$ 7,616	$ 7,489	$ 7,631	$ 9,189	$ 9,514
2	Distribution Supervision Total	100-10	9,976	7,616	7,489	7,631	9,189	9,514
3	Operation Centre - Distribution	100-21	5,776	6,184	5,480	6,293	6,054	6,410
4	Asset Management - Distribution	100-22	1,195	1,339	1,437	1,382	949	1,034
5	Preventative Maintenance - Distribution	100-23	1,298	1,379	1,515	1,536	1,484	2,202
6	Distribution Operations - General	100-24	2,853	3,554	3,656	3,657	4,347	4,809
7	Emergency Management	100-25	4,976	5,173	5,490	5,452	5,590	6,350
8	Distribution Operations Total	100-20	16,099	17,629	17,578	18,319	18,424	20,805
9	Distribution Corrective - Meters	100-31	785	1,094	1,022	925	1,090	1,286
10	Distribution Corrective - Propane	100-32	-	(0)	24	3	7	4
11	Distribution Corrective - Leak Repair	100-33	607	652	740	837	1,005	981
12	Distribution Corrective - Stations	100-34	322	492	487	421	556	729
13	Distribution Corrective - General	100-35	207	322	509	397	354	324
14	Distribution Maintenance Total	100-30	1,922	2,560	2,782	2,584	3,013	3,323
15	**Distribution Total**	**100**	**27,997**	**27,804**	**27,849**	**28,534**	**30,627**	**33,642**
16								
17	Transmission Supervision	200-11	1,767	1,485	1,857	1,889	2,194	1,841
18	Transmission Supervision Total	200-10	1,767	1,485	1,857	1,889	2,194	1,841
19	Pipeline Operation	200-21	954	886	1,002	962	1,784	2,212
20	Right of Way	200-22	2,086	2,329	1,700	1,677	1,220	1,363
21	Compression	200-23	1,391	1,661	1,689	1,585	1,536	1,451
22	Gas Control	200-24	1,896	1,724	1,548	1,939	1,848	1,909
23	Transmission Pipeline Integrity Project (TPIP)	200-25 *	-	3,044	4,147	4,065	3,284	4,202
24	Transmission Operations Total	200-20	6,328	9,643	10,086	10,228	9,672	11,137
25	Pipeline - Maintenance	200-31	268	249	220	211	47	128
26	Compression - Maintenance	200-32	153	182	167	157	100	202
27	TPIP - Maintenance	200-33 *	-	1,091	1,731	435	877	338
28	Transmission Maintenance Total	200-30	421	1,522	2,118	803	1,024	668
29	**Transmission Total**	**200**	**8,516**	**12,650**	**14,061**	**12,920**	**12,890**	**13,646**
30								
31	LNG Plant Operations	300-11	536	586	575	524	781	720
32	LNG Plant Operations Total	300-10	536	586	575	524	781	720
33	LNG Plant Maintenance	300-21	200	242	363	291	198	254
34	LNG Plant Maintenance Total	300-20	200	242	363	291	198	254
35	**LNG Plant Total**	**300**	**736**	**828**	**938**	**815**	**980**	**974**
36								
37	Measurement Operations	400-11	4,316	3,828	3,172	3,159	3,356	3,346
38	Measurement Operations Total	400-10	4,316	3,828	3,172	3,159	3,356	3,346
39	Measurement Maintenance	400-21	2,784	3,122	4,104	2,899	1,870	1,929
40	Measurement Maintenance Total	400-20	2,784	3,122	4,104	2,899	1,870	1,929
41	**Measurement Total**	**400**	**7,100**	**6,949**	**7,276**	**6,059**	**5,226**	**5,274**
42								
43	Facilities Management	*** 500-10	4,818	4,929	4,820	5,074	4,857	5,389
44	Shops & Stores	500-20	2,920	2,618	2,906	2,807	3,233	3,405
45	Operations Engineering	500-30	4,002	4,283	5,210	5,118	5,512	5,572
46	Property Services	500-40	402	560	568	881	760	1,011
47	System Integrity	500-50	1,503	1,607	1,718	1,904	2,005	2,042
48	Environmental Health & Safety	500-60	1,722	1,385	1,312	1,162	1,066	1,191
49	Operations Governance	500-70	1,861	1,032	1,011	1,159	1,351	1,464
50	**General Operations Total**	**500**	**17,228**	**16,414**	**17,545**	**18,106**	**18,784**	**20,075**

* TPIP was capitalized in 2003.

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (CONT'D)
($000)

Line No.	Particulars	Reference		2003	2004	2005	2006	2007	2008
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)
1	Energy Efficiency	600-10		$ 1,464	$ 1,396	$ 1,043	$ 1,556	$ 1,599	$ 1,740
2	Marketing - Supervision	600-20		569	563	473	562	1,174	553
3	Corporate & Marketing Communicatio	600-30		3,021	2,305	2,993	2,853	2,156	2,695
4	Marketing Planning & Development	600-40		(0)	390	692	686	607	568
5	**Marketing Total**	**600**		**5,054**	**4,654**	**5,201**	**5,656**	**5,536**	**5,557**
6									
7	Customer Care - Supervision	700-10		342	543	645	735	724	878
8	Customer Contact - ABSU contract	700-20		42,234	42,728	43,554	44,168	45,366	46,426
9	Bad Debt Management and Administ	700-30		5,923	5,615	4,336	10,743	4,521	5,022
10	Customer Management & Sales	700-40		2,035	1,514	1,891	2,361	2,484	3,108
11	**Customer Care Total**	**700**		**50,535**	**50,400**	**50,426**	**58,007**	**53,094**	**55,434**
12									
13	Business & IT Services - Supervision	800-10		1,308	1,770	1,858	1,858	1,857	1,011
14	Application Management	800-20		6,182	5,098	6,212	6,183	7,687	7,861
15	Infrastructure Management	800-30		5,319	5,127	4,947	5,472	5,675	5,270
16	Procurement Services	800-40		708	734	583	674	681	670
17	**Business & IT Services Total**	**800**		**13,516**	**12,730**	**13,600**	**14,188**	**15,901**	**14,812**
18									
19	Administration & General	900-11		10,778	5,901	1,833	2,564	2,391	3,736
20	Insurance	900-12		3,879	5,873	5,083	5,085	5,078	4,661
21	Finance and Regulatory Affairs	900-13		7,844	6,694	7,352	7,265	7,929	8,670
22	Shared Services Agreement	900-14	**	-	5,334	4,870	4,035	4,144	3,613
23	Corporate Administration Total	900-10		22,502	23,801	19,138	18,949	19,543	20,681
24	Forecasting	900-20		1,725	1,200	1,102	1,184	1,025	934
25	Public Affairs	900-30		1,626	1,975	1,477	1,359	1,373	1,394
26	Business Development	900-40		581	1,046	1,195	1,194	982	1,017
27	Human Resources	900-50		4,462	3,727	3,538	4,027	4,724	4,540
28	(OPEB)	900-60		6,406	7,538	7,485	8,208	8,289	7,761
29	**Administration & General Total**	**900**		**37,302**	**39,288**	**33,935**	**34,921**	**35,936**	**36,326**
30									
31	**Total Gross O&M Expenses**			**167,985**	**171,718**	**170,831**	**179,206**	**178,973**	**185,739**
32									
33	Less: Coastal Lease		***	-	-	-	-	-	-
34	Less: Vehicle Lease Reclass			(1,918)	(1,900)	(1,911)	(1,872)	(2,008)	(1,988)
35	Less: Capitalized Overhead			(25,104)	(25,892)	(26,212)	(27,111)	(27,401)	(27,566)
36									
37	**Total O&M Expenses**			**$ 140,963**	**$ 143,926**	**$ 142,708**	**$ 150,223**	**$ 149,564**	**$ 156,186**

Notes:

** Process for allocated shared services were not centralized in 2003.

*** The 2004 Annual Report subtracted the Coastal Lease after Gross O&M total. For comparable reporting to 2003 the lease cost has been taken out of Facilities line 500-10.

The Activity View groups cost centers based on similar process activities.

This view differs from the Department view used elsewhere in the Application which groups cost centers by business function.

Mapping of Department to Activity View:

President & CEO is mapped to activity line 900-Administration (Insurance, admin, and other).
Marketing is spilt into activities 600-Marketing and 700-Customer Care.
B&ITS is spilt amongst 400-Measurement, 500-General ops (Ops Engineering, System integrity, Facilities management, Shops and stores, and Property services), and 800-Business & IT.
Transmission is spilt into 200-Transmission and 300-LNG maintenance activities.

HR & Ops Governance is spilt into 500-General Ops (Environmental & Ops Health and Safety, Operations Governance, and Fleet services) and 900-Admin activities.
Finance is mapped to activity 900-Administration.

Bad Debt management (Meter read, Unlock, Relight, Lock offs) in Distribution department view is mapped to activity 700-Customer Care.
Meter Exchange (Industrial & Residential) in Distribution department view is mapped to activity 400-Measurement.

Headcount History and Demographic Data

Headcount During the PBR Period Has Remained Below 2003 Levels

TERASEN GAS INC.
EMPLOYEES HISTORICAL COMPARISON
"HEADCOUNT" AS AT DECEMBER 31ST
FOR THE YEARS 2003 TO 2008

Line No.	Particulars	2003	2004	2005	2006	2007	2008
1	Distribution	786	631	487	463	492	510
2	Finance & Regulatory Affairs	47	57	51	55	64	66
3	Business & IT Services	54	66	266	260	307	317
4	Human Resources & Operations Governance	90	206	99	97	86	100
5	Marketing & Business Development	52	65	65	77	84	80
6	Gas Supply & Transmission	103	96	136	131	81	82
7	Corporate	65	-	-	-	-	-
8	Total Headcount	1197	1121	1104	1083	1114	1155

Actual Retirements Have Averaged 13% Per Year During the PBR Period

	2003			2004			2005		
	Eligible Retirees	Retire-ments	Eligible Employees Retiring (%)	Eligible Retirees	Retire-ments	Eligible Employees Retiring (%)	Eligible Retirees	Retire-ments	Eligible Employees Retiring (%)
COPE	151	12	7.9%	158	12	7.6%	153	11	7.2%
IBEW	252	27	10.7%	256	18	7.0%	255	20	7.8%
M&E	102	27	26.5%	65	60	92.3%	70	11	15.7%
Total	505	66	13.1%	479	90	18.8%	478	42	8.8%

	2006			2007			2008		
	Eligible Retirees	Retire-ments	Eligible Employees Retiring (%)	Eligible Retirees	Retire-ments	Eligible Employees Retiring (%)	Eligible Retirees	Retire-ments	Eligible Employees Retiring (%)
COPE	160	15	9.4%	157	13	8.3%	149	19	12.8%
IBEW	231	38	16.5%	230	17	7.4%	195	37	19.0%
M&E	67	8	11.9%	37	2	5.4%	45	7	15.6%
Total	458	61	13.3%	424	32	7.5%	389	63	16.2%

More Than 1/3 of our Workforce is Age 50 or Older

2003

Age Category	COPE	IBEW	M&E	Total
< 25	5			5
25 - 29	15	2	15	32
30 - 34	42	19	23	84
35 - 39	69	48	44	161
40 - 44	71	73	49	193
45 - 49	71	56	65	192
50 - 54	87	120	58	265
55 - 59	54	97	50	201
60 - 64	18	34	12	64
65+				
Total	432	449	316	1197

2004

Age Category	COPE	IBEW	M&E	Total
<25	17		1	18
25 - 29	17	2	11	30
30 - 34	39	20	25	84
35 - 39	63	39	35	137
40 - 44	74	71	48	193
45 - 49	76	56	51	183
50 - 54	86	107	50	243
55 - 59	49	104	19	172
60 - 64	22	37	2	61
65+				
Total	443	436	242	1121

2005

Age Category	COPE	IBEW	M&E	Total
<25	15	3	2	20
25 - 29	19	3	13	35
30 - 34	30	10	26	66
35 - 39	65	42	35	142
40 - 44	76	64	48	188
45 - 49	77	60	44	181
50 - 54	78	83	59	220
55 - 59	59	110	15	184
60 - 64	18	45	6	69
65+				
Total	437	420	248	1105

2006

Age Category	COPE	IBEW	M&E	Total
<25	23	1	4	28
25 - 29	22	1	16	39
30 - 34	27	9	26	62
35 - 39	58	42	33	133
40 - 44	82	51	50	183
45 - 49	68	57	39	164
50 - 54	79	77	58	214
55 - 59	61	112	22	195
60 - 64	25	33	7	65
65+				
Total	445	383	255	1083

2007

Age Category	COPE	IBEW	M&E	Total
< 25	21	4	1	26
25 - 29	29	11	18	58
30 - 34	24	18	20	62
35 - 39	51	39	39	129
40 - 44	71	47	47	165
45 - 49	82	74	42	198
50 - 54	79	70	60	209
55 - 59	59	103	24	186
60 - 64	26	42	12	80
65+	1			1
Total	443	408	263	1114

2008

Age Category	COPE	IBEW	M&E	Total
< 25	26	10	4	40
25 - 29	33	21	22	76
30 - 34	23	27	26	76
35 - 39	46	41	40	127
40 - 44	76	52	52	180
45 - 49	86	81	46	213
50 - 54	67	60	56	183
55 - 59	60	94	32	186
60 - 64	25	38	10	73
65+		1		1
Total	442	425	288	1155

Additional FTE Requirements in 2010 and 2011

TERASEN GAS INC.
FULL-TIME EQUIVALENT (FTE) EMPLOYEES BASED ON PAID HOURS
FOR THE YEARS 2003 TO 2011

Line No.	Particulars	2003	2004	2005	2006	2007	2008	2009 (Forecast)	2010 (Proposed)	2011 (Proposed)
1	Distribution	510	499	488	468	481	503	545	574	577
3	Finance & Regulatory Affairs	58	59	61	59	58	63	68	67	67
4	Business & IT Services	311	284	298	293	300	311	357	370	377
5	Human Resources & Operations Governance	92	93	90	85	84	87	76	85	88
6	Marketing & Business Development	86	65	64	75	80	80	112	127	131
7	Gas Supply & Transmission	89	85	89	80	81	80	90	96	96
8	President's Office	43	4	2	2	2	2	2	2	2
9	Total FTE*	1189	1089	1092	1062	1087	1127	1250	1321	1338

The Conference Board of Canada
Insights You Can Count On

Compensation Planning Outlook 2008

Compensation Outlook

The "Alberta Effect" Puts Upward Pressure on Pay

HUMAN RESOURCE MANAGEMENT

The Conference Board of Canada
Insights You Can Count On

Compensation Planning Outlook 2008
by *Stephen Clarke*

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Preface

Compensation Planning Outlook 2008 is the 26th edition of this publication, which summarizes the results of The Conference Board of Canada's annual compensation survey. In July 2007, a questionnaire was sent to 1,989 predominantly large and medium-sized Canadian organizations operating in a variety of regions and sectors. A total of 319 respondents participated in the survey, representing a response rate of 16 per cent.

This publication was prepared under the auspices of the Conference Board's Compensation Research Centre (CRC) and was made possible through the ongoing support of the funding members and of survey participants. We owe a special thank you to all of the individuals who took the time to answer this year's comprehensive questionnaire and to the many organizations that participate year after year. Their efforts are very much appreciated, as it is through the commitment of respondents that The Conference Board of Canada is able to produce this report.

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Compensation Outlook

The "Alberta Effect" Puts Upward Pressure on Pay

At a Glance

- The average non-union pay increase for 2008 is projected to be 3.9 per cent nationally. The highest increases—averaging 5.7 per cent—will occur in the oil and gas industry.
- Wage settlements for unionized workers are expected to average 3.1 per cent in 2008.
- Recruitment and retention issues continue to place intense pressure on businesses; 73 per cent of survey respondents reported challenges with recruiting and/or retaining employees with specific skills.

A strong economy, coupled with a tight labour market, will put upward pressure on pay in 2008. Canada's domestic economy is expected to perform well next year despite the slowdown south of the border. However, with our unemployment rates at record low levels, labour shortages are being felt across the country. This is especially true in Western Canada, where Alberta's oil and gas sector will continue to see strong growth; Saskatchewan's mining and agriculture sectors are robust; and a construction boom, along with a positive outlook for manufacturing in Manitoba, will drive growth in that province. Overall, Canadian workers can once again expect an increase in real wages in 2008.

The average non-union pay increase for 2008, based on the responses of the 319 organizations participating in this year's Compensation Planning Outlook survey, is projected to be 3.9 per cent nationally. This increase is 1.7 percentage points ahead of the 2.2 per cent inflation rate forecast for 2008.

Wage increases will vary by industry and region:

- Projected increases are highest in the oil and gas industry, with an average of 5.7 per cent across all employee groups. Wage gains in this sector are strong nationally but are being driven by Alberta's surging economy, contributing to intense competition for labour as the unemployment rate remains well below 4 per cent—the lowest in the land. The labour market in Alberta will tighten even more next year, as the number of people relocating to the province (on a net basis) is subsiding due to soaring housing costs and improved economic prospects in neighbouring provinces.[1]
- Above-average increases are also expected in the construction, natural resources (excluding oil and gas), and transportation and utilities sectors. Projected increases in these sectors range from 4.4 per cent to 4.8 per cent. Organizations in the education and health, food, beverage and tobacco, services (professional, scientific, technical), and government sectors are also expected to see above-average increases in 2008 (between 4.1 and 4.2 per cent).

1 Economic information contained in this Executive Summary was taken from the Conference Board's Canadian and Provincial Outlook reports, fall and summer 2007 issues.

- Below-average increases are anticipated in the retail trade sector (3.7 per cent), as well as in the chemical, pharmaceutical and allied products, not-for-profit, and wholesale trade sectors (each at 3.6 per cent).
- The lowest average salary increases (3.1 per cent) are expected in the communications/telecommunications and services (accommodation, food, personal) sectors.
- Non-unionized employees in the broader public sector can anticipate average pay increases of 4.1 per cent, compared to 3.9 per cent for employees in the private sector. Anticipated wage settlements for unionized workers are expected to average 3.1 per cent in 2008—3.4 per cent in the public sector, and 3 per cent in the private sector.
- Provincially, Alberta will take the lead, with an average increase of 5.2 per cent. Average increases in British Columbia are projected at 4.2 per cent, while Saskatchewan and Manitoba are also expected to see increases above the national average, at 4.6 per cent.
- Quebec, Ontario, and the Atlantic region are expected to see increases that are below the national average (3.6, 3.4 and 3.2 per cent, respectively).

Overall, anticipated 2008 pay increases sit below those reported for 2007. The actual average salary increase in 2007 was 4.2 per cent, three-tenths of a percentage point higher than last fall's projection for the year. As in previous years, salary increases were not applied "across the board," as the average salary increase for satisfactory performers was 3.6 per cent, compared to an average of 5.5 per cent for those whose performance was outstanding.

Increases to 2007 salary budgets also averaged 4.3 per cent, with approximately 1 per cent of organizations freezing their budgets. Budget increases for 2008 are projected to fall slightly to 4.1 per cent as organizations try to keep their wage bills in check. The average salary structure (range) increase was 2.8 per cent in 2007, which includes the 11 per cent of organizations that did not adjust their ranges last year. The average planned structure increase for 2008 is 2.9 per cent; just over 5 per cent of organizations are planning to hold their ranges steady in the coming year.

The outlook for the Canadian economy remains healthy despite ongoing challenges in the trade sector. Canadian exporters and manufacturers (in the wood products and construction materials sectors, for example) have been hard hit and will continue to struggle in light of the slowdown in the U.S. housing market and the high-flying loonie. Higher resource prices, however, have served to soften the blow, generating solid income gains, especially in Western Canada. As a result, there remains plenty of momentum in the Canadian economy. Growth in gross domestic product is anticipated to accelerate from 2.6 per cent this year to 2.8 per cent in 2008.

Inflation continues to present little concern—it is expected to slow from 2.4 per cent this year to 2.2 per cent in 2008. While growth in corporate profits (before taxes) is anticipated to ease off from this year's 9.8 per cent to 7.3 per cent in 2008, corporate balance sheets remain in remarkable condition.

The Canadian economy is running near full capacity. The unemployment rate of 6 per cent is at a 33-year low and is projected at 5.9 per cent for 2008, contributing to a further tightening of the labour market, especially in Western Canada, where projections for unemployment rates in 2008 again call for record low levels. As the labour market tightens, voluntary turnover rates increase. According to survey respondents, the average turnover rate across all industries for 2007 is 8.5 per cent, over half a percentage point higher than in 2006.

With labour shortages continuing and turnover rates on the rise, recruitment and retention issues remain the hot issue for Canadian organizations. Almost three-quarters (73 per cent) of this year's survey respondents reported challenges in these areas, especially concerning employees with specific skills. The situation continues to be particularly acute in British Columbia and Alberta, where 9 in 10 employers reported recruitment and retention challenges. There appears to be no relief in sight for 2008, as almost 60 per cent of survey respondents from Alberta expect to increase the size of their workforce by an average of 7 per cent next year.

As we approach 2008, growth strategies in the oil and gas sector will create pressure across the land. As a consequence, attracting and retaining talent continues to be the number one priority for compensation planners, and the shortage of skilled workers and the "Alberta effect" will put upward pressure on pay across the country.

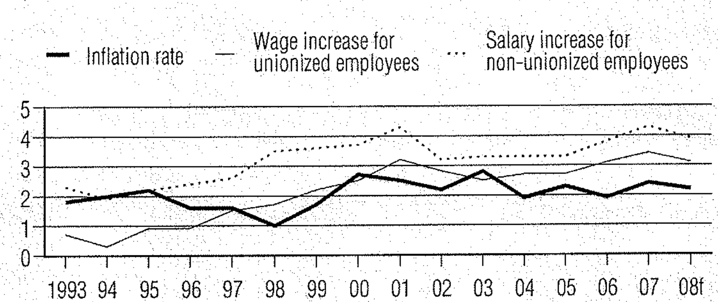
CHAPTER 1

Compensation Planning and Practices

Chapter Summary

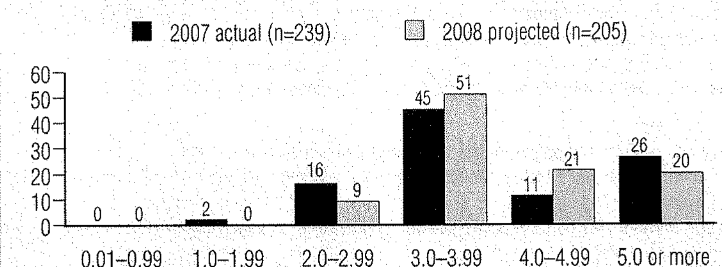
- Real wage gains are projected once again for 2008, with an average non-union pay increase of 3.9 per cent. The average increase for 2007 was 4.2 per cent. Outstanding performers received average increases of 5.5 per cent; those deemed "satisfactory" received 3.6 per cent.
- With competition for valuable talent even tighter than in 2007, very few organizations are expected to freeze salary budgets and ranges in the coming year.
- More than 8 in 10 respondents have variable pay plans, primarily in the form of cash bonuses or incentives. Targets vary considerably across industry and employee groups, with the average cost representing 12.2 per cent of total base pay spending.
- The use of traditional stock option plans continues to decline.

Chart 1
Inflation vs. Increases, 1993–2008
(percentage change)



f = forecast
Sources: The Conference Board of Canada; Human Resources and Social Development Canada, Workplace Information Directorate.

Chart 2
Average Salary Increase Distribution
(percentage of organizations)



Note: Totals may not equal 100 due to rounding.
Source: The Conference Board of Canada.

MANAGING BASE PAY

For the 13th consecutive year, base pay increases are predicted to exceed inflation, resulting in real gains for Canadian employees. The average non-union pay increase for 2008 is projected to be 3.9 per cent, 1.7 percentage points ahead of the 2.2 per cent inflation rate forecast for the year.

Table 1
2007 Actual Compensation Increases, by Employee Group*
(non-unionized employees)

Employee group	Policy line (range increase; %)** zeros included	Policy line (range increase; %)** zeros excluded	Total increase to budget (%) zeros included	Total increase to budget (%) zeros excluded	Employees receiving an increase (%)	Average increase for those receiving one (%)	Average increase among all employees (%) zeros included	Average increase among all employees (%) zeros excluded	2007 average base salary ($)
Senior executives	2.7	3.5	4.4	4.5	91.2	4.8	4.7	4.8	249,010
	2.5	*3.0*	*3.9*	*4.0*	*100.0*	*4.0*	*4.0*	*4.0*	*225,000*
Executives	3.0	3.6	4.5	4.6	93.0	4.7	4.5	4.6	168,273
	2.5	*3.0*	*4.0*	*4.0*	*100.0*	*4.0*	*3.9*	*3.9*	*161,092*
Management	3.0	3.4	4.3	4.4	94.2	4.5	4.3	4.3	100,883
	2.7	*3.0*	*3.9*	*3.9*	*99.0*	*4.0*	*3.8*	*3.8*	*96,681*
Professional—technical	2.9	3.4	4.4	4.5	93.3	4.5	4.2	4.2	72,881
	2.5	*2.8*	*3.9*	*3.9*	*99.0*	*4.0*	*3.6*	*3.6*	*70,900*
Professional—non-technical	2.8	3.2	4.3	4.3	93.5	4.4	4.2	4.2	68,676
	2.5	*2.8*	*3.8*	*3.8*	*99.0*	*3.8*	*3.6*	*3.6*	*67,763*
Technical and skilled trades	2.7	3.2	4.2	4.3	93.9	4.1	3.9	4.0	60,053
	2.6	*2.9*	*3.8*	*3.9*	*100.0*	*3.5*	*3.5*	*3.5*	*59,300*
Clerical and support	2.7	3.2	4.2	4.2	91.5	4.1	3.9	3.9	43,923
	2.5	*2.8*	*3.7*	*3.7*	*98.0*	*3.6*	*3.5*	*3.5*	*43,316*
Service and production	2.4	2.9	4.0	4.1	93.4	3.9	3.8	3.9	45,129
	2.5	*2.8*	*3.6*	*3.7*	*100.0*	*3.5*	*3.5*	*3.5*	*40,000*
Overall	**2.8**	**3.3**	**4.3**	**4.3**	**92.3**	**4.4**	**4.2**	**4.2**	**n.a.**
	2.6	***2.9***	***3.8***	***3.8***	***98.5***	***3.9***	***3.7***	***3.7***	***n.a.***

Employee Group Definitions
Senior executives: all executives reporting directly to the chief executive officer
Executives: all other executives
Management: senior and middle management: plan, develop, and implement policies and programs
Professional—technical: analysts, engineers, information technology specialists, developers, etc.
Professional—non-technical: all other professionals: accountants, lawyers, doctors, etc., excluding salespeople
Technical and skilled trades: technologists, technicians, millwrights, etc.
Clerical and support: secretaries, clerks, coordinators, assistants, word-processing staff
Service and production: service, production, maintenance, transportation, etc.

***Definitions**
Policy line: increase to salary ranges, among organizations with ranges
Total increase to budget: increase to salary budget, including all budgeted components of compensation program (range, merit, economic, progression, promotion, etc.)
Employees receiving an increase: as a percentage of employees in category
Average increase for those receiving one: increase to those receiving an increase (i.e., total increase from all sources—range, merit, economic, progression—rolled into base pay)
Average increase among all employees: based on all employees in category
Average base salary: approximate average annual base salary after the increases have been applied

n.a. = not applicable
Note: For each result, the top number is the average (mean) and the bottom number (in italics) is the median.
Source: The Conference Board of Canada.

We expect that salary budget increases will average 4.1 per cent in 2008, slightly lower than the average seen in 2007 (4.3 per cent) but generally higher than the average witnessed in previous years (3.8 per cent in 2006, 3.3 per cent in 2005, and 3.4 per cent in 2004). For the second consecutive year, approximately 1 per cent of respondents anticipate an overall freeze on salary budgets for the coming year—down from 2006 (2 per cent) and 2005 (5 per cent).

As in the past three years, salary range (or "structure") movement is expected to edge upwards, with an average increase of 2.9 per cent planned for 2008, up from 2.8 per cent in 2007, 2.4 per cent in 2006, and 2.1 per cent in 2005. In addition, significantly fewer organizations are planning to hold their ranges constant in the coming year. Just over 5 per cent of organizations with salary ranges are planning to freeze them in 2008, down from 11 per cent in 2007 and 13 per cent in 2006.

Table 2
2008 Planned Compensation Increases, by Employee Group
(non-unionized employees)

	Policy line (range increase; %)		Total increase to budget (%)		Average increase among all employees (%)	
Employee group*	**zeros included**	**zeros excluded**	**zeros included**	**zeros excluded**	**zeros included**	**zeros excluded**
Senior executives	2.8	3.0	4.1	4.3	4.1	4.1
	3.0	*3.0*	*3.8*	*4.0*	*3.5*	*3.5*
Executives	2.9	3.1	4.2	4.3	4.1	4.2
	3.0	*3.0*	*4.0*	*4.0*	*3.8*	*3.8*
Management	3.0	3.1	4.2	4.3	4.0	4.0
	3.0	*3.0*	*4.0*	*4.0*	*3.5*	*3.5*
Professional—technical	3.0	3.1	4.2	4.3	4.0	4.0
	3.0	*3.0*	*4.0*	*4.0*	*3.5*	*3.5*
Professional—non-technical	3.0	3.1	4.2	4.2	4.0	4.0
	3.0	*3.0*	*4.0*	*4.0*	*3.5*	*3.5*
Technical and skilled trades	2.9	3.1	4.1	4.2	3.9	4.0
	3.0	*3.0*	*4.0*	*4.0*	*3.8*	*3.9*
Clerical and support	2.9	3.1	4.1	4.1	3.8	3.8
	2.8	*3.0*	*3.8*	*3.8*	*3.5*	*3.5*
Service and production	2.7	2.9	3.9	4.0	3.6	3.7
	2.5	*2.7*	*3.5*	*3.6*	*3.5*	*3.5*
Overall	**2.9**	**3.1**	**4.1**	**4.2**	**3.9**	**3.9**
	2.8	***3.0***	***3.8***	***3.9***	***3.5***	***3.5***

*See Table 1 for definitions.
Note: For each result, the top number is the average (mean) and the bottom number (in italics) is the median.
Source: The Conference Board of Canada.

Table 3
2007 Actual Compensation Increases, by Industry, Sector, and Region
(non-unionized employees)

	Policy line (range increase; %)		Total increase to budget (%)		Employees receiving an increase (%)	Average increase for those receiving one (%)	Average increase among all employees (%)	
	zeros included	zeros excluded	zeros included	zeros excluded			zeros included	zeros excluded
Overall	**2.8**	**3.3**	**4.3**	**4.3**	**92.3**	**4.4**	**4.2**	**4.2**
Industry								
Oil and gas (n=18)	5.6	5.6	6.8	6.8	97.0	6.8	**6.8**	6.8
Construction* (n=4)	6.4	6.4	5.8	5.8	97.2	5.5	**4.6**	4.6
Natural resources, excluding oil and gas (n=11)	4.7	5.3	5.4	5.4	98.7	5.6	**5.5**	5.5
Transportation and utilities (n=26)	3.2	3.4	4.6	4.7	95.9	4.9	**4.7**	4.7
Education and health (n=20)	3.3	3.3	4.6	4.6	95.5	4.1	**3.9**	3.9
Food, beverage, and tobacco (n=9)	3.5	3.7	4.0	4.2	93.0	3.9	**4.0**	4.2
Services—Professional, scientific, technical (n=25)	2.5	2.8	4.3	4.3	93.6	4.7	**4.4**	4.4
Government (n=32)	3.2	3.5	4.5	4.7	99.2	4.7	**4.9**	4.9
Retail trade (n=15)	2.0	2.9	4.4	4.4	83.0	4.3	**4.1**	4.1
Chemical, pharmaceutical, and allied products (n=15)	2.7	3.2	3.4	3.7	90.4	3.9	**3.6**	3.7
Not-for-profit (n=10)	2.3	2.9	3.9	3.9	96.7	3.7	**3.6**	3.6
Wholesale trade (n=9)	2.6	2.6	3.8	3.8	87.3	3.8	**3.5**	3.5
Manufacturing (n=37)	2.3	2.9	3.7	3.7	96.0	3.7	**3.7**	3.7
Finance, insurance, and real estate (n=53)	2.2	2.7	3.9	4.0	84.9	4.1	**3.8**	4.0
High-technology (n=15)	2.4	3.1	3.4	3.4	90.0	3.6	**3.3**	3.3
Communications and telecommunications (n=9)	2.8	4.2	3.2	3.2	83.0	3.1	**2.5**	2.6
Services—Accommodation, food, personal (n=9)	2.9	3.8	3.7	3.7	96.1	3.3	**3.2**	3.2
Sector								
Private sector (n=233)	2.6	3.2	4.2	4.2	92.0	4.3	**4.1**	4.1
Public sector (n=86)	3.3	3.5	4.7	4.8	93.4	4.7	**4.5**	4.5
Region								
British Columbia (n=24)	3.1	3.7	4.7	4.8	87.3	4.9	**4.5**	4.6
Alberta (n=53)	4.1	4.7	6.2	6.2	95.8	6.2	**6.0**	6.0
Manitoba/Saskatchewan (n=27)	3.6	3.8	5.1	5.1	93.7	4.9	**4.6**	4.6
Ontario (n=163)	2.4	3.0	3.7	3.7	92.3	3.8	**3.6**	3.6
Quebec (n=38)	2.4	2.5	3.7	3.8	92.4	4.0	**3.9**	3.9
Atlantic (n=12)	2.3	2.6	3.3	3.9	90.0	2.7	**2.5**	2.5

*Caution must be exercised in interpreting the data from this industry. Only two organizations provided information on range and overall salary increases for 2007–08.
Note: The sample sizes above (n=) indicate the number of organizations providing a response for at least one actual or projected increase.
Source: The Conference Board of Canada.

Table 4
2008 Planned Compensation Increases, by Industry, Sector, and Region
(non-unionized employees)

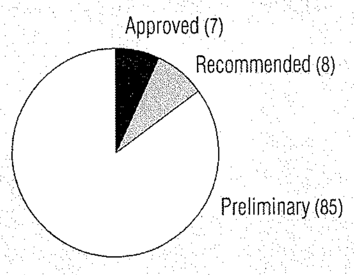
	Policy line (range increase; %)		Total increase to budget (%)		Average increase among all employees (%)	
	zeros included	zeros excluded	zeros included	zeros excluded	zeros included	zeros excluded
Overall	**2.9**	**3.1**	**4.1**	**4.2**	**3.9**	**3.9**
Industry						
Oil and gas (n=18)	4.3	4.3	5.5	5.5	**5.7**	5.7
Construction* (n=4)	6.4	6.4	5.7	5.7	**4.8**	4.8
Natural resources, excluding oil and gas (n=11)	3.4	3.4	4.6	4.6	**4.7**	4.7
Transportation and utilities (n=26)	3.4	3.4	4.5	4.5	**4.4**	4.4
Education and health (n=20)	3.7	3.7	4.6	4.6	**4.2**	4.2
Food, beverage, and tobacco (n=9)	3.9	3.9	4.5	4.5	**4.2**	4.2
Services—Professional, scientific, technical (n=25)	2.4	2.9	4.5	4.5	**4.2**	4.2
Government (n=32)	2.9	3.1	4.4	4.4	**4.1**	4.1
Retail trade (n=15)	2.5	3.3	4.7	4.7	**3.7**	3.7
Chemical, pharmaceutical, and allied products (n=15)	2.9	2.9	3.5	3.8	**3.6**	3.6
Not-for-profit (n=10)	3.7	4.1	3.9	3.9	**3.6**	3.6
Wholesale trade (n=9)	3.1	3.1	3.5	3.5	**3.6**	3.6
Manufacturing (n=37)	2.4	2.6	3.6	3.7	**3.4**	3.5
Finance, insurance, and real estate (n=53)	2.3	2.5	3.6	3.8	**3.4**	3.6
High-technology (n=15)	2.3	2.3	3.6	3.6	**3.3**	3.3
Communications and telecommunications (n=9)	2.8	3.0	3.0	3.2	**3.1**	3.1
Services—Accommodation, food, personal (n=9)	2.8	3.0	3.7	3.7	**3.1**	3.1
Sector						
Private sector (n=233)	2.8	3.0	4.0	4.1	**3.9**	3.9
Public sector (n=86)	3.3	3.3	4.6	4.6	**4.1**	4.1
Region						
British Columbia (n=24)	3.4	3.4	5.0	5.0	**4.2**	4.2
Alberta (n=53)	4.0	4.0	5.4	5.4	**5.2**	5.2
Manitoba/Saskatchewan (n=27)	3.2	3.4	4.8	4.8	**4.6**	4.6
Ontario (n=163)	2.5	2.8	3.6	3.7	**3.4**	3.4
Quebec (n=38)	2.5	2.5	3.5	3.6	**3.6**	3.6
Atlantic (n=12)	2.7	2.7	3.4	3.4	**3.2**	3.2

*Caution must be exercised in interpreting the data from this industry. Only two organizations provided information on range and overall salary increases for 2007–08.
Note: The sample sizes above (n=) indicate the number of organizations that provided a response for at least one actual or projected increase.
Source: The Conference Board of Canada.

The average salary increase for 2007 was 4.2 per cent among all non-unionized employees across all responding organizations. Nearly 93 per cent of employees received an increase to base salary in 2007, taking home raises of 4.4 per cent on average.

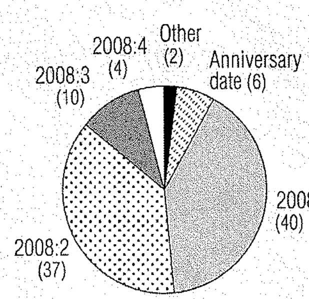
Outstanding performers received an average increase of 5.5 per cent, compared with 3.6 per cent for solid performers. The degree to which organizations differentiate base pay increases according to performance varies widely: outstanding performers garnered increases ranging from less than 1 percentage point up to 8 percentage points higher than those given to solid performers.

Chart 3
Current Status of Salary Budget Recommendations for 2008
(n=310; percentage of organizations)



Source: The Conference Board of Canada.

Chart 4
Planned Implementation of Salary Increases for 2008
(n=307; percentage of organizations)



Source: The Conference Board of Canada.

Sixty-one per cent of organizations provided data on increases for solid and outstanding performance. Among these, nearly 8 in 10 (79 per cent) reward outstanding performance with increases that are up to twice the average increase given to satisfactory performers. Nearly 1 in 5 (19 per cent) reward outstanding performance with increases that are two to three times the average increase for satisfactory performance, while only 2 per cent reported that average increases for outstanding performers are more than three times those for satisfactory performers.

VARIABLE PAY

The majority of Canadian organizations (83 per cent) have at least one annual variable pay plan. These plans are especially popular in the private sector, where 93 per cent of organizations reported having at least one. By comparison, 56 per cent of public sector organizations have one or more variable pay plans.

Table 5
Prevalence of Annual Variable Pay, by Sector and Employee Group
(per cent; based on organizations that reported for each employee category; non-unionized employees)

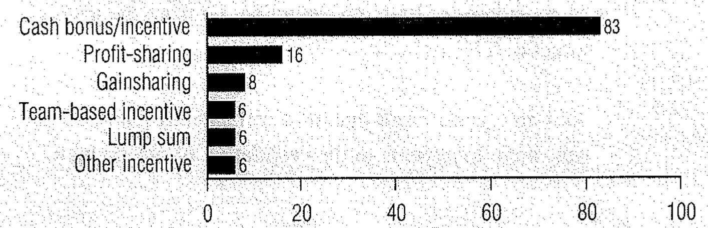
Employee group	Public sector (n=86)	Private sector (n=233)	All sectors combined (n=319)
Overall	**56**	**93**	**83**
Senior executives	52	80	73
Executives	47	77	69
Management	47	89	78
Professional—technical	35	76	65
Professional—non-technical	38	72	63
Technical and skilled trades	20	40	35
Clerical and support	34	68	59
Service and production	13	42	34

Source: The Conference Board of Canada.

Cash bonus or incentive plans are the most common form of annual variable pay plan, used by 83 per cent of organizations that have at least one of these plan types. Profit-sharing plans rank a distant second at 16 per cent, followed by gainsharing plans at 8 per cent, and team-based incentives and lump sum payments at 6 per cent each.

Variable pay targets differ considerably across employee groups and also across industries. The actual cost of annual variable pay plans averaged 12.2 per cent of total base pay spending in 2007. These costs are highest for organizations in the oil and gas sector (averaging 19 per cent of total base pay spending), compared with those in the government sector (a 6.4 per cent average).

Chart 5
Annual Variable Pay—Plan Types
(n=265; per cent; based on organizations with at least one annual variable pay plan in place)



Note: Figures do not add to 100 because some respondents have more than one plan.
Source: The Conference Board of Canada.

Table 6
Annual Variable Pay Plan Payouts, by Employee Group
(expressed as percentage of base salary; non-unionized employees)

2007 Payouts*

	Average payout			Percentage of organizations		
Employee group	Target payout	Actual payout	Receiving payouts**	Exceeded target	Met target	Fell short of target
Senior executives (n=184)	38.6	47.3	93.8	60	17	24
Executives (n=180)	28.7	35.3	94.0	60	17	22
Management (n=216)	15.8	19.1	91.8	56	15	29
Professional—technical (n=179)	10.1	12.1	89.1	50	21	28
Professional—non-technical (n=172)	9.8	12.3	90.6	50	21	29
Technical and skilled trades (n=91)	7.2	9.1	95.7	54	19	27
Clerical and support (n=160)	5.7	7.3	94.9	57	18	25
Service and production (n=85)	6.0	8.9	92.2	49	24	27

2008 Projected Payouts*

Employee group	Target payout	Plan maximum
Senior executives (n=171)	38.9	65.5
Executives (n=165)	28.8	49.0
Management (n=194)	15.8	27.2
Professional—technical (n=160)	10.1	17.3
Professional—non-technical (n=159)	9.8	17.5
Technical and skilled trades (n=84)	7.0	13.8
Clerical and support (n=147)	5.5	11.4
Service and production (n=81)	5.9	11.6

*2007 payouts refer to payouts based on 2006 results and paid in 2007; 2008 payouts refer to payouts based on 2007 results, to be paid in 2008.
**Percentage of eligible employees in category.
Source: The Conference Board of Canada.

In 2007, on average, 93 per cent of eligible employees in organizations with variable pay received a payout. Overall spending on these plans is expected to increase slightly in 2008, with plan targets forecast to average 11.6 per cent of base pay spending, up from the average target of 11.1 per cent in 2007.

Among organizations that have variable pay plans, 35 per cent include payouts in the calculation of pensionable earnings for all employees. An additional 4.9 per cent consider only a portion of variable pay as pensionable, while 9.8 per cent report that variable pay is included in pensionable earnings only for selected employees, typically executives.

Almost one-quarter (62) of the organizations that have variable pay made changes to their plans in 2007. Most cases involved adjusting targets.

Table 7
2008 Variable Pay Plan Targets for Selected Industries, by Employee Group
(expressed as percentage of base salary)

Employee group	Government	Financial services	Manufacturing	Oil and gas	Transportation and utilities	Natural resources	Chemical, pharmaceutical and allied products	Communications/ telecom	High-tech
Senior executive	20.7	38.1	41.3	49.2	35.6	52.1	33.9	37.7	47.0
Executives	15.5	28.2	29.8	32.5	27.0	39.6	27.0	30.1	35.0
Management	10.9	15.4	16.0	22.5	13.3	23.3	17.6	14.9	16.6
Professional—technical	9.0	9.1	10.4	13.9	9.3	13.4	10.8	9.3	15.4
Professional—non-technical	8.6	9.4	9.3	12.9	9.5	12.1	10.2	9.4	16.4
Technical and skilled trades	7.9	5.9	7.7	7.5	7.4	9.2	7.1	8.8	8.5
Clerical and support	5.3	5.4	6.3	7.0	6.2	6.9	5.3	7.0	6.9
Service and production	4.0	5.8	6.5	7.3	6.5	7.5	5.6	5.0	7.0

Source: The Conference Board of Canada.

Table 8
Variable Pay Plan Target Adjustments, by Employee Group
(per cent; based on organizations providing 2007 and 2008 targets)

Employee group	Adjusting target	Increasing	Average target increase	Decreasing	Average target decrease	Overall average target movement*
Senior executives (n=163)	13.5	9.8	6.8	3.7	–13.3	1.3
Executives (n=155)	13.5	7.7	4.1	5.8	–4.0	0.6
Management (n=187)	11.2	6.4	4.3	4.8	–3.7	0.9
Professional—technical (n=154)	10.4	7.8	1.4	2.6	–2.4	0.5
Professional—non-technical (n=154)	10.4	7.8	1.3	2.6	–2.4	0.4
Technical and skilled trades (n=82)	11.0	7.3	2.6	3.7	–1.3	1.3
Clerical and support (n=143)	9.8	6.3	1.7	3.5	–1.0	0.7
Service and production (n=79)	6.3	5.1	2.1	1.3	–1.5	1.4

*Average target movements based upon data provided by those organizations adjusting targets.
Source: The Conference Board of Canada.

The prevalence of medium-term or "mid-term" plans that pay out after two or three years has increased again. In 2007, nearly 18 per cent of organizations employed these types of incentives, up from 13 per cent in 2006 and 8 per cent in 2005. Twenty-three per cent of private sector organizations use these types of plans, while they are virtually non-existent among public sector respondents.

LONG-TERM INCENTIVE PLANS

The prevalence of long-term incentive plans (LTIPs) remains stable, with 48 per cent of organizations reporting the use of at least one type of LTIP in 2007. LTIPs are far more common in the private sector, where 61 per cent of organizations use them. The vast majority of firms that are publicly traded (79 per cent) continue to offer LTIPs, as do most of the firms that are controlled by a publicly traded company. These incentive plans are not common in the public sector, with just over 12 per cent of organizations reporting their use.

Stock option plans remain the most prevalent form of LTIP but continue to decline slowly in popularity. More than half (52 per cent) of organizations with an LTIP currently have this type of plan in place, down from a high of 73 per cent 10 years ago when the Conference Board first collected this information. The prevalence of other types of LTIPs remains largely unchanged from the situation in 2006: 23 per cent of firms with LTIPs use restricted share units, and 18 per cent have long-term cash plans. Long-term cash is the type of plan most often used by the few public sector firms with LTIPs.

Table 9
Prevalence of Long-Term Incentive Plans,* by Sector and Employee Group
(per cent; based on organizations that reported for each employee category; non-unionized employees)

	Public sector (n=86)	Private sector (n=233)
Overall	**12**	**61**
Senior executives	9	53
Executives	6	50
Management	3	36
Professional—technical	0	18
Professional—non-technical	0	15
Other non-management	0	10

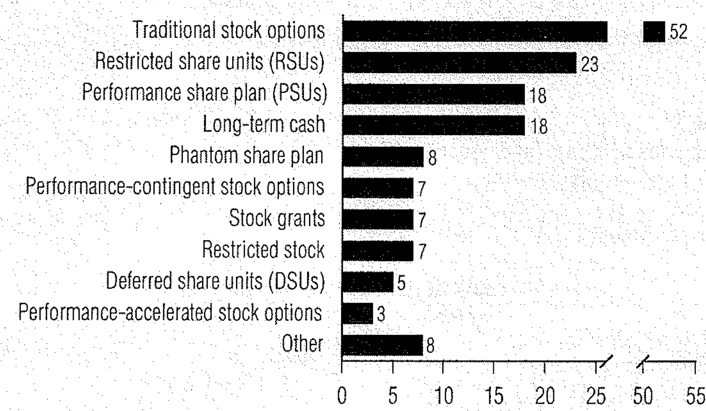
*Refers only to ongoing plans. For the purposes of this question, any ad hoc rewards of stock options or grants are excluded.
Source: The Conference Board of Canada.

Table 10
Long-Term Incentive Plans—Eligibility, by Employee Group*
(n=153; per cent; based on organizations with at least one LTIP in place)

	Organizations with LTIP for this category	Employees eligible for LTIP(s) (average)	Employees receiving LTI in 2007 (average)
Senior executives	86	96	93
Executives	80	96	93
Management	56	77	77
Professional—technical	27	76	60
Professional—non-technical	23	80	62
Other non-management	15	65	55

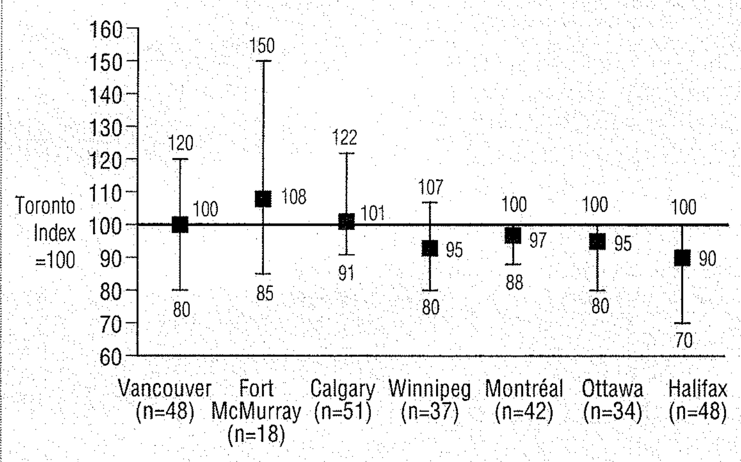
*Definitions provided to respondents:
% eligible: as percentage of total employees in the category.
% receiving: as percentage of those employees eligible for the incentive.
Source: The Conference Board of Canada.

Chart 6
Long-Term Incentive Plans*—Plan Types
(n=153; per cent; based on organizations with at least one LTIP in place)



*Refers only to ongoing plans. For the purposes of this question, any ad hoc rewards of stock options or grants are excluded.
Note: Figures do not add to 100 because some respondents have more than one plan.
Source: The Conference Board of Canada.

Chart 7
Regional Compensation Levels



■ = average (mean) for location; high and low numbers represent range of responses.
Note: For ease of comparison, the Toronto area was used as the base (index = 100).
Source: The Conference Board of Canada.

While typically used for executive-level compensation, LTIPs have also been applied to individuals below that level. Twenty-three per cent of organizations with LTIPs offer them to non-management-level employees (e.g., professional non-technical staff such as accountants, lawyers, and doctors), while 15 per cent of organizations offer these types of plans to other non-management employees (e.g., clerical and support, service and production). Seventeen per cent of respondents with LTIPs made changes to their plan in the past 12 months, while 10 per cent are anticipating changes in 2008.

REWARDS STRATEGY AND PRIORITIES

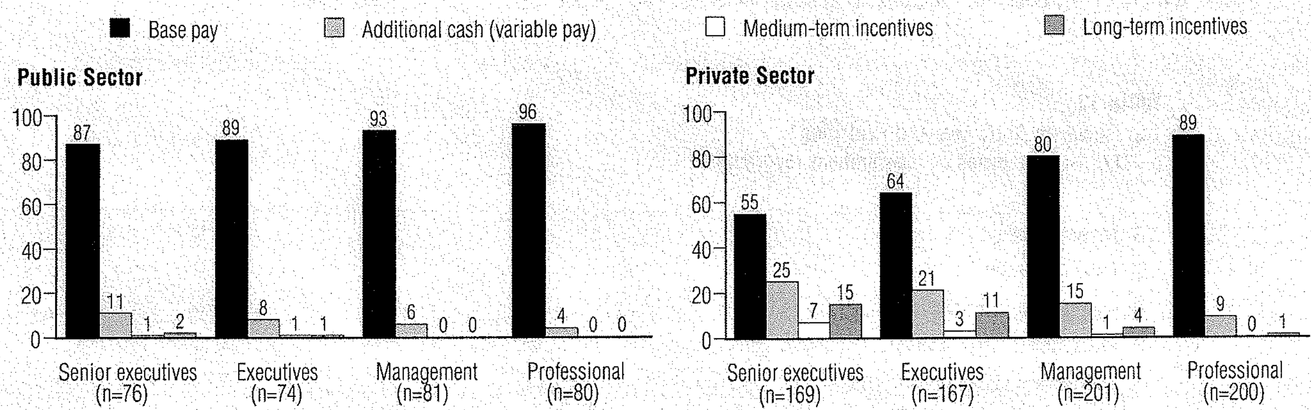
The prevalence of market-based pay strategies has changed minimally over the past few years. The majority of responding organizations (65 per cent) employed this approach in 2007, compared with 63 per cent in 2006 and 64 per cent in 2005. The use of non-monetary recognition awards increased slightly more, to 70 per cent, up from 62 per cent in 2006. Nearly 4 in 10 responding organizations use spot cash awards.

Twenty-three per cent of responding organizations use regional rates of pay, with the highest rates being applied in Fort McMurray.

Base pay continues to represent the most significant component of total cash compensation, particularly in the public sector. The proportion of compensation represented by annual variable pay remained steady in 2007. In the private sector, there was no change in the use of long-term incentives for senior executives.

Attracting and retaining talent and maintaining competitive market position continue to be the top three rewards activities and priorities for organizations. The relative weight applied to each of these priorities has changed since

Chart 8
Distribution of Total Cash Compensation, by Sector*
(percentage of total cash)



*Refers to the desired distribution of total cash components based on the design of the total cash compensation strategy.
Note: Totals may not equal 100 due to rounding.
Source: The Conference Board of Canada.

Table 11
Prevalence of Selected Approaches to Compensation Strategy
(percentage of organizations)

	In place	Implemented but disbanded	Being considered	Considered but decided against	Never considered
Broadbanding (n=291)	30	4	10	18	38
Competency-based pay (n=295)	32	1	13	9	45
Team-based pay (n=276)	8	1	4	8	80
Market pricing (n=301)	65	0	9	5	21
Non-monetary recognition awards (n=303)	70	0	15	2	13
Spot cash awards (n=289)	37	2	10	5	46

Note: Totals may not equal 100 due to rounding.
Source: The Conference Board of Canada.

2005, especially with regard to attracting talent. In 2007, more than half of organizations (55.5 per cent) identified this particular objective as their top priority, compared with 45.5 per cent in 2006 and 42 per cent in 2005. That comes as no surprise, given the human resources challenges currently facing organizations, especially in Western Canada.

Table 12
Top Rewards Activities and Priorities*
(n=317; per cent; based on organizations reporting)

1. Attracting talent	55.5
2. Retaining talent	52.7
3. Maintaining competitive position	47.3
4. Reviewing strategy and ensuring alignment with business objectives	37.5
5. Connecting pay and performance	30.6
6. Containing pension and benefit costs	19.9
7. Communicating rewards to employees	17.7
8. Maximizing effectiveness of variable pay	12.6
9. Managing rewards on a total rewards basis	12.6
10. Ensuring internal equity	8.8
11. Managing executive compensation and long-term incentives	4.4

*Respondents were asked to select (from a list) their top three rewards and activities over the next 12 to 18 months.
Source: The Conference Board of Canada.

CHAPTER 2

Human Resource Management

Chapter Summary

- Recruitment and retention pressures remained at the same high levels seen in 2006, especially in the natural resources sector (excluding oil and gas), education and health, and government sectors.
- In 2007, accounting and finance, skilled trades, and engineering workers were in top demand.

RECRUITMENT AND RETENTION

The pressures of a hot labour market currently manifest themselves in ever-increasing recruitment and retention challenges. Nearly three-quarters of organizations (73 per cent) are experiencing difficulty attracting or retaining employees with particular skills. The organizations that are more likely to experience these difficulties include those in the natural resources sector (excluding oil and gas; 100 per cent), education and health (85 per cent), and government (81 per cent). The skills in highest demand are consistent with those cited in 2006 and include accounting and finance, skilled trades, and engineering. Specialist information technology (IT), sales and marketing, and management round out the top six most sought-after skills.

Table 13
Top Professions/Specializations/Position Types in Demand*
(n=231; per cent; based on organizations reporting difficulty recruiting and/or retaining particular skills)

1. Accounting/finance	52
2. Skilled trades	36
3. Engineering—electrical, mechanical, etc.	26
4. Specialist IT	23
5. Sales and marketing	18
6. Management	17
7. Professional staff	13
8. Physical sciences	8
9. General IT	8
10. Human resources	7
11. Executives	6
12. Senior executives	4
13. Technical staff	3
Other**	27

*Respondents were asked to select the top three professions, specializations or position types that are most difficult in terms of recruitment and/or retention.
**A wide variety of other responses were provided, representing a broad range of industries and occupations. The most common were health-care professionals (including nurses, pharmacists, and technicians), researchers, auditors, project managers, and operations managers.
Source: The Conference Board of Canada.

To address the issues of recruitment and retention, nearly three-quarters of responding organizations have developed either formal compensation strategies or informal approaches to enhancing rewards packages for individuals in high demand. Generally speaking, there is no universal approach, but by a substantial margin, base pay adjustments continue to be the most common approach, followed by signing bonuses, referral bonuses, and retention bonuses.

Table 14
Specific Compensation Strategies/Approaches to Attract and/or Retain Key Individuals
(n=235, per cent; based on organizations that reported having at least one strategy)

	Formal strategy	Ad hoc approach	Both	Total*
Adjustments to base pay (n=159)	15	43	10	68
Signing bonuses (n=131)	7	46	3	56
Referral bonuses (n=97)	36	6	0	42
Retention bonuses (n=96)	12	26	3	41
Milestone or project bonuses (n=61)	4	19	3	26
Enhanced relocation support (n=54)	7	15	1	23
Stock options or grants (n=48)	11	8	2	21
Hot skills bonuses (n=33)	6	8	1	15
Enhanced variable pay programs (n=33)	7	5	2	14
Stay bonuses (n=28)	1	10	0	11
Other (n=16)	4	2	1	7

Other compensation strategies include:
Enhanced benefits to support work–life balance (leaves, vacation)
Market premiums
Relocation assistance (i.e., housing subsidies, interest buy-downs, sale protection)

*Overall percentage of organizations with strategy in place.
Source: The Conference Board of Canada.

Table 15
Historical Usage of Specific Compensation Strategies/Approaches
(percentage of all organizations)

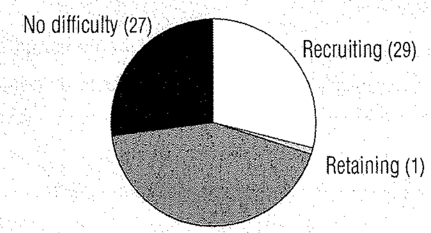
	Outlook 2002	Outlook 2004	Outlook 2006	Outlook 2007	Outlook 2008
Adjustments to base pay	72	72	70	75	68
Signing bonuses	51	44	48	51	56
Retention bonuses	35	27	33	36	41
Stock options	33	33	21	21	20
Milestone or project bonuses	29	27	19	23	26
Enhanced variable pay	27	22	14	13	14
Hot skills bonuses	18	14	10	16	14

Source: The Conference Board of Canada.

Last year saw labour market pressures place great strain on voluntary turnover rates, especially among specific employee groups. The same pressures manifested themselves again in 2007, with the average annual turnover rate hitting 8.5 per cent, up from 7.9 per cent last year. In addition to this overall turnover rate, a small number of survey participants also provided turnover data for specific employee groups:

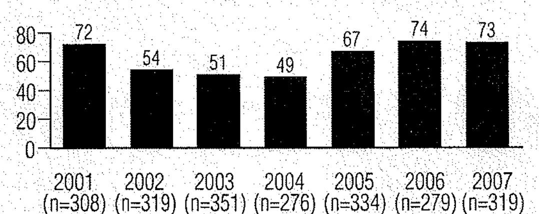
- For "top performers," the average voluntary turnover rate is 2.4 per cent, based on data provided by 13 per cent of organizations surveyed. That compares with a rate of 5.2 per cent for top performers last year, and 4.1 per cent two years ago.
- For "solid performers," the rate is 4.7 per cent, based on data provided by 11 per cent of organizations surveyed.
- For "poor performers," the rate is 5.5 per cent, based on data provided by 12 per cent of organizations surveyed.
- For "employees with less than two years of service," the rate is 7 per cent, based on data provided by 25 per cent of organizations surveyed.

Chart 9
Difficulty Recruiting and Retaining Particular Skills
(n=319; percentage of organizations)



Source: The Conference Board of Canada.

Chart 10
Difficulty with Recruiting and Retaining—Trend Over Time
(percentage of organizations reporting difficulties with recruitment and/or retention)



Source: The Conference Board of Canada.

Table 16
Absenteeism and Voluntary Turnover Rates, by Industry

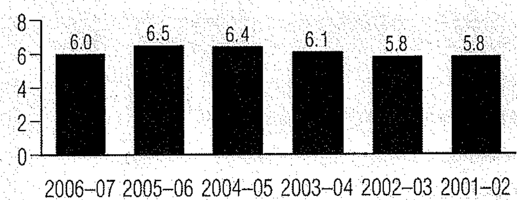
	Absenteeism rate* (days per employee) (n=181)	Voluntary turnover rate (average percentage) (n=236)
Overall	**6.0**	**8.5**
Industry		
Natural resources, excluding oil and gas	7.4	5.8
Oil and gas	5.0	7.6
Manufacturing	5.3	6.0
Food, beverage, and tobacco products	1.0	7.6
Chemical, pharmaceutical, and allied products	6.1	4.6
Construction	**	**
High-technology	4.2	8.5
Communications and telecommunications	8.2	11.1
Transportation and utilities	7.3	6.9
Finance, insurance, and real estate	5.1	9.6
Wholesale trade	5.7	7.0
Retail trade	5.4	18.1
Education and health	7.5	5.9
Government	7.7	6.3
Not-for-profit	5.0	9.6
Services—Accommodation, food, personal	6.9	14.6
Services—Professional, scientific, technical	5.0	13.3

*Please refer to Chart 11 notes for definitions.
**Not shown due to small sample sizes.
Source: The Conference Board of Canada.

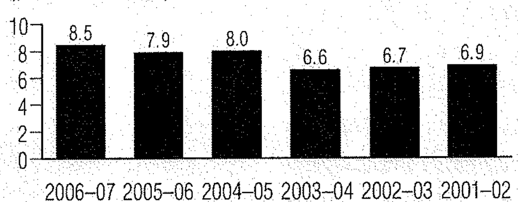
- For "employees with critical skills," the rate is 3.6 per cent, based on data provided by 12 per cent of organizations surveyed, compared with a rate of 4.8 per cent for this employee group in 2006.
- For "employees with hot skills," the rate is 3.8 per cent, based on responses from 9 per cent of organizations surveyed, compared with last year's rate of 3.3 per cent.

Chart 11
Absenteeism and Voluntary Turnover Rates
(based on responses of all organizations; rates reflect the period August 1 to July 31 except for 2005–07, where rates reflect July 1 to June 30)

Absenteeism Rate
(days per employee)



Voluntary Turnover Rate
(per cent; average)



Notes:
1 Absenteeism is defined as an employee's absence from work (with or without pay) due to illness, disability, personal or family reasons for a period of at least half a day but less than 52 consecutive weeks. Maternity, adoptive, paternity, vacation and holiday, and bereavement leave and jury duty are excluded.
2 Voluntary turnover applies to regular employees only, and does not include early retirements or severances.

Source: The Conference Board of Canada.

Table 17
Turnover Rates Among Specific Employee Groups
(average percentage)

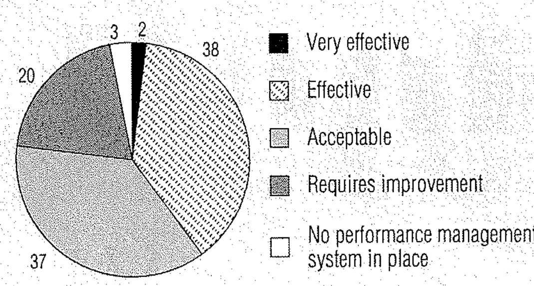
	Turnover rate
Top performers (n=43)	2.4
Solid performers (n=35)	4.7
Poor performers (n=37)	5.5
Employees with less than two years' service (n=80)	7.0
Employees with critical skills (n=38)	3.6
Employees with hot skills (n=29)	3.8

Source: The Conference Board of Canada.

PERFORMANCE MANAGEMENT

Over the past few years, there has been a consistent increase in the perceived effectiveness of performance management systems among survey respondents. While participants continue to remain confident in the effectiveness of their performance management systems, fewer organizations indicated that their system is either "very effective" or "effective" in 2007 (40 per cent) than in 2006 (45 per cent). More than one-third (37 per cent) of organizations rated their performance management system as "acceptable," and one in five (20 per cent) believe that improvement is needed.

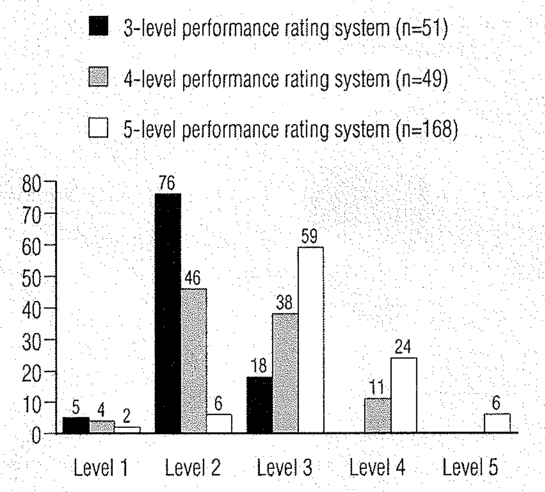
Chart 12
Effectiveness of Performance Management System
(n=315; percentage of all organizations)



Source: The Conference Board of Canada.

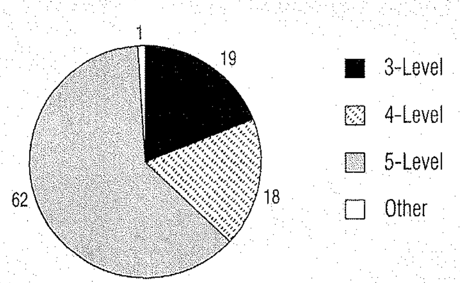
The proportion of organizations using a performance appraisal rating system has remained consistent in recent years. The majority of organizations (88 per cent) currently use such a system, with five-level (62 per cent) and three-level (19 per cent) systems being the most common. Thirteen per cent of the organizations with a rating system force a performance distribution, while 42 per cent have distribution guidelines or recommendations in place for managers to use when carrying out performance assessments.

Chart 13
Performance Distribution
(average percentage of employees)



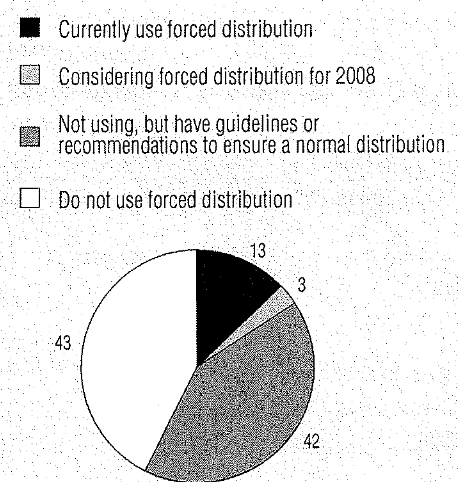
Notes:
1 For each of the three rating systems, "Level 1" represents unsatisfactory performers.
2 The high degree of variability in performance appraisal systems does not allow for labels to be assigned to each level presented in the chart.
3 Totals do not equal 100 due to rounding.
Source: The Conference Board of Canada.

Chart 14
Number of Performance Levels
(n=272; percentage of organizations)



Source: The Conference Board of Canada.

Chart 15
Forced Performance Distribution and Guidelines
(n=286; percentage of organizations with performance appraisal rating system)



Note: Total does not add to 100 due to rounding.
Source: The Conference Board of Canada.

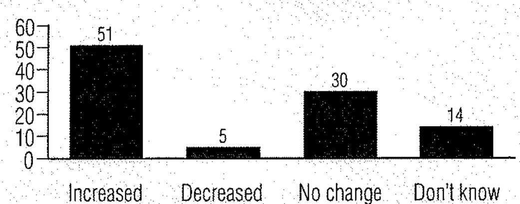
BENEFITS

The rising cost of employee health benefits is a major concern for organizations. Just over half (51 per cent) of respondents indicated an increase in costs in 2007, by an average of 9.6 per cent. Only 5 per cent of organizations reported a decrease in the cost of their health benefits for active employees, by an average of 11 per cent. Among organizations with health benefits for retirees, just over one-third (34 per cent) reported an increase in their costs, by an average of 9.7 per cent. Forty-three per cent of organizations incur their health-care benefits expense in the form of premiums, and a similar proportion (45 per cent) incurs actual claims expenses.

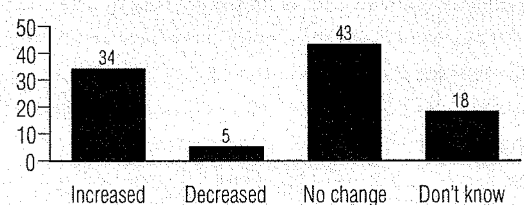
Twenty-seven per cent of organizations have a flexible benefits plan in place for all employees, while 14 per cent provide this benefit to only certain segments of their employee population. Fewer than 5 per cent are considering implementing a flexible benefits plan in 2008. An equivalent proportion of organizations (27 per cent) also offers a health spending account to all staff, and one-quarter (25 per cent) do so for specific employee groups. An additional 5 per cent are considering implementing health spending accounts in the coming year.

Chart 16
Changes in Health-Care Benefit Costs

Health-Care Benefit Costs for Active Employees
(n=273; percentage of organizations responding to question)



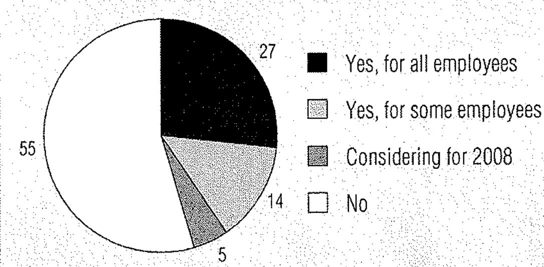
Health-Care Benefit Costs for Retirees
(n=148; percentage of organizations reporting health-care benefit costs for retirees)



Source: The Conference Board of Canada.

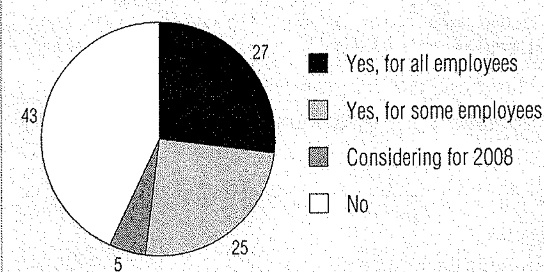
The use of flex days—employees can take time off in addition to their regular vacation entitlement and personal leave—remains a relatively uncommon approach to combatting workforce pressures. Only 19 per cent have implemented this benefit, sometimes referred to as "Golden Fridays," with the average allotment among these organizations being 11 days per employee.

Chart 17
Prevalence of Flexible Benefits Plans
(n=317; percentage of organizations)



Note: Total does not add to 100 due to rounding.
Source: The Conference Board of Canada.

Chart 18
Prevalence of Health Spending Accounts
(n=313; percentage of organizations)



Source: The Conference Board of Canada.

CHAPTER 3

Collective Bargaining

Chapter Summary

- The projected average wage increase among unionized employees is 3.1 per cent in 2008. The average for 2007 was 3.4 per cent.
- Four in 10 respondents have annual variable pay plans for their unionized employees, with cash bonus or incentive plans being most common. The majority of variable pay plans met or exceeded payout targets in 2007. Unionized workers in these organizations received payouts averaging 8 per cent of base pay.
- The key bargaining issue anticipated for management in the coming year is productivity; for unions, it is expected to be wages.

BASE PAY INCREASES

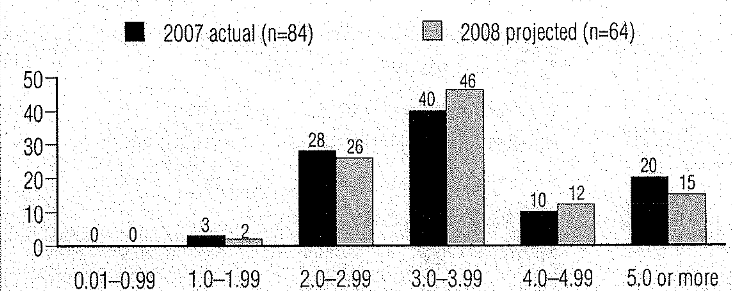
For unionized employees, the average wage increase projected for 2008 is 3.1 per cent: 3 per cent in the private sector and 3.4 per cent in the public sector.

The average actual negotiated increase in 2007 was 3.4 per cent. Employees in the public sector received increases that averaged 3.5 per cent, while those in the private sector averaged 3.3 per cent.

VARIABLE PAY

The prevalence of annual variable pay plans for unionized employees has risen in recent years. In 2007, 45 per cent of unionized organizations had variable pay for unionized employees, up from 31 per cent in 2001. Cash bonus or incentive plans continue to be the most common forms of variable pay for unionized employees, followed by profit-sharing and gainsharing plans. Most variable pay plans achieved (23 per cent) or exceeded (55 per cent) payout targets in 2007, and the majority (95 per cent) of employees received a payout.

Chart 19
Distribution of Base Pay Increases*
(per cent)



*A base pay increase refers to the average increase applied to the base wage rate, for the year specified (includes any cost of living allowance increases).
Note: The totals do not add to 100 due to rounding.
Source: The Conference Board of Canada.

Table 18
Base Pay Increases*
(per cent, except for years in contract)

		Average # of years in contract (n=88)	Year 1 2007 (n=83)	Year 2 2008 (n=83	Year 3 2009 (n=76)
Contracts negotiated	(mean)	3.2	3.4	3.4	3.4
since Jan. 1, 2007	(median)	3.0	3.0	3.0	3.0

		Average # of years in contract (n=71)	Year 1 2008 (n=64)	Year 2 2009 (n=62)	Year 3 2010 (n=54)
Contracts to be negotiated before	(mean)	3.3	3.1	3.2	3.2
Dec. 31, 2008	(median)	3.0	3.0	3.0	3.0

*A base pay increase refers to the average increase applied to the base wage rate, for the year specified (includes any cost of living allowance increases).
Source: The Conference Board of Canada.

Table 19
Annual Variable Pay Plan Payouts
(percentage of base pay)

2007 Payouts
(actual, based on 2006 performance)

Target payout (n=46)	4.6
Actual payout (n=46)	8.0
% of employees receiving (n=45)	94.5
% of organizations falling short of target	22.5
% of organizations meeting target	22.5
% of organizations surpassing target	55.0

2008 Payouts
(projections, based on 2007 performance)

Target payout (n=41)	4.8
Plan maximum (n=35)	7.1

Source: The Conference Board of Canada.

Table 20
Current Negotiation Issues*
(n=138; percentage of unionized organizations)

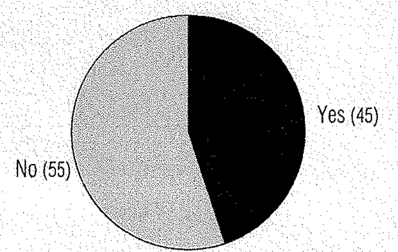
Management issues	
1. Productivity	49
2. Flexible work practices	45
3. Business competitiveness	42
4. Wages	38
5. Health, pensions, benefits	37
6. Training and skills development	22
7. Organizational change	18
8. Outsourcing/contracting out	12
9. Employment/pay equity	9
10. Technological change	9
11. Variable pay	4
12. Employment security	1

Union issues	
1. Wages	83
2. Health, pensions, benefits	73
3. Employment security	41
4. Outsourcing/contracting out	30
5. Training and skills development	19
6. Employment/pay equity	15
7. Flexible work practices	15
8. Organizational change	7
9. Variable pay	5
10. Technological change	3
11. Productivity	1
12. Other	7

*Respondents were provided with a list of 12 possible choices (plus "other") and asked to indicate the top three negotiation issues for both management and union.
Source: The Conference Board of Canada.

Ten organizations reported having a long-term incentive plan in place for their unionized employees. These plans include traditional stock options and performance-contingent stock options.

Chart 20
Prevalence of Annual Variable Play
(n=184; percentage of unionized organizations)



Source: The Conference Board of Canada.

NEGOTIATION ISSUES

The majority (81 per cent) of unionized organizations do not expect work stoppages in 2008. Only 5 of 184 unionized organizations (3 per cent) that participated in the survey believe that an interruption is possible in the coming year.

Nearly half of the unionized respondents (47 per cent) believe that the labour–management relationship within their organization is more cooperative than uncooperative, while 4 in 10 (41 per cent) perceive it to be balanced. As in recent years, most organizations (68 per cent) expect the relationship with their unions to remain stable over the next two years. One in six unionized respondents (16 per cent) believes its labour–management relationship will improve, while 6 per cent—10 organizations—believe it will deteriorate.

Facts About the Unionized Employers in the Survey

- 58 per cent of responding organizations have unionized employees.
- 1,132 agreements are currently in place.
- 282 agreements, covering 133,990 employees, expire in 2008.

Source: The Conference Board of Canada.

According to approximately 4 in 10 organizations, the key bargaining issues for management in 2008 will be productivity, flexible work practices, and business competitiveness. Wages, and health, pension and other benefits are expected to top the list of management issues among 3 in 10 organizations.

By a wide margin, wages continue to be identified as the key union issue in the coming year. Health benefits, pensions and employment security round out the top bargaining issues for labour in 2008.

APPENDIX A

Respondent Profile

(Total number of responding organizations = 319)

	Percentage of organizations
Industrial Classification	
Natural resources, excluding oil and gas	3
Oil and gas	6
Manufacturing	12
Food, beverage, and tobacco products	3
Chemical, pharmaceutical, and allied products	5
Construction	1
High-technology	5
Communications and telecommunications	3
Transportation and utilities	8
Finance, insurance, and real estate	17
Wholesale trade	3
Retail trade	5
Education and health	6
Government	10
Not-for-profit	3
Services—Accommodation, food, and personal	3
Services—Professional, scientific, and technical	8
Characteristics of Responding Organizations	
Sector	
Private sector corporation	74
Federal/provincial Crown corporation or agency	22
Municipal government	5
Operations	
Canadian only	56
North American	13
Global	31

	Percentage of organizations
Ownership	
Publicly traded shares	26
Controlled by Canadian publicly traded company	4
Controlled by foreign publicly traded company	15
Privately held	21
Not applicable	34
Assets (Canadian operations)	
$0–$99 million	21
$100–$999 million	29
$1 billion and over	50
Annual sales/service revenue (Canadian operations)	
$0–$99 million	18
$100–$999 million	40
$1 billion and over	42
Number of employees	
Fewer than 500	23
500–1,499	27
1,500–5,000	27
Over 5,000	23
Total number of employees	1,528,127
Total non-unionized employees	827,188

APPENDIX B

Participating Organizations

A total of 319 organizations participated in the Compensation Planning Outlook 2008 survey. The following participants have authorized the publication of their names. At their request, 11 organizations have been excluded from this list.

3M Canada
Abitibi Consolidated Inc.
ADP Canada
Agricorp
Agrium Inc.
Agropur Cooperative
Alberta Cancer Board
Alberta Energy and Utilities Board
Alcan Inc.
Alcohol and Gaming Commission of Ontario
Alcool NB Liquor
Allstate Insurance Company of Canada
AltaLink Management Ltd.
AMEC
Apotex Inc.
Association of Universities and Colleges of Canada
Astra Zeneca Canada Inc.
ATB Financial
ATCO Electric
Atomic Energy of Canada Limited
AXA Canada
Ballard Power Systems Inc.
Bank of Canada
Bank of Montreal
Bausch & Lomb Canada
BC Public Service Agency
Bell Aliant
Bell Canada
Best Buy Canada Ltd.
Bethany Care Society
Blue Mountain Resorts Ltd.
BNP Paribas (Canada)
Bombardier Aerospace
Bombardier Inc.
BP Canada Energy Company
Brewers Distributor Ltd.
Brookfield Properties Corporation
Business Development Bank of Canada
CAE Inc.
Caisse de dépôt et placement du Québec
Calgary Co-operative Association Ltd.
Calgary Health Region
Cameco Corporation
Canada's Wonderland Company
Canada Bread Company Ltd.
Canada Deposit Insurance Corporation
Canada Forgings Inc.
Canada Lands Company Limited
Canada Post Corporation
Canadelle
Canadian Blood Services
Canadian Broadcasting Corporation
Canadian Institute for Health Information
Canadian Nuclear Safety Commission
Canadian Pacific Railway
Canadian Tire Corporation, Limited
Canadian Tire Financial Services
Canadian Wheat Board

Capital Health
Cara Operations Limited
Cedara Software
Ceridian Canada Ltd.
Children's Hospital of Eastern Ontario
Chubb Insurance Company of Canada
CI Investments
CIBC Mellon
Cirque du Soleil
City of Calgary
City of Regina
CN
Cognos Inc.
COM DEV International Ltd.
Commissionaires (Great Lakes)
Compass Group Canada
Concentra Financial
Corporation of the City of Kitchener
Corus Entertainment
Crane Plumbing Canada Corp.
Credit Union Central of BC
Crown Metal Packaging Canada LP
CVRD Inco Limited
Deloitte
Desjardins Financial Security
Devon Canada Corporation
Direct Energy
Dofasco Inc.
E.I. DuPont of Canada Company
EDS Canada
EHC-Global (formerly Escalator Handrail Company, Inc.)
Elk Valley Coal Corporation
Enbridge Inc.
Enerflex Systems Ltd.
Enerplus Resources Fund
ENMAX Corporation
EPCOR Utilities Inc.
Ericsson Canada Inc.
Expertech Network Installations
Export Development Canada
Fairmont Hotels & Resorts
Farm Credit Canada
Farmers Co-operative Dairy
Federated Cooperative Limited
FedEx Canada
Financial Transactions & Reports Analysis Centre of Canada
Finning (Canada)
First Calgary Savings
Fluor Corporation
Foresters
FortisAlberta Inc.
Fountain Tire Ltd.
Frito Lay Canada
Gamma-Dynacare Medical Laboratories
General Dynamics Land Systems — Canada
General Electric Canada
General Motors of Canada Limited
Gibson Energy Ltd.
GlaxoSmithKline Inc.
Goldcorp Canada Ltd — Perceiving Joint Venture
Goodmans LLP
Goodyear Canada Inc.
Gore Mutual Insurance Company
Government of Alberta
Great Canadian Gaming Corporation
Group Deschenes Inc.
Hadrian Manufacturing Inc.
Halifax Regional Municipality
HDS Retail North America
Hewitt Equipment Limited
Hewlett-Packard (Canada) Co.
Home Depot Canada
Hudson Bay Mining & Smelting Co., Limited
Husky Injection Molding Systems
Hydro-Québec
IBM Canada Ltd.
ICBC
IHS Energy (Canada) Ltd.
Imperial Oil Limited
Independent Electricity System Operator (IESO)
Industrial Alliance Insurance and Financial Services Inc.
ING Canada
Intergraph Canada Ltd.
International Development Research Centre (IDRC)
Investment Dealers Association of Canada
Investors Group Inc.
IPSCO Inc.
Island Savings Credit Union
Ivaco Rolling Mills LP
Ivanhoe Cambridge
Jervis B. Webb Company of Canada Ltd.
Kellogg Canada Inc.
Kinder Morgan Canada

KONE
L-3 Wescam
Lanxess Inc.
Laurentian Bank of Canada
Ledcor Group of Companies
Lehigh Inland Cement Limited
Lilydale Inc.
Liquor Control Board of Ontario (LCBO)
London Health Sciences Centre
Manitoba Hydro
Manulife Financial
Maple Leaf Consumer Foods
Maxxam Analytics Inc.
MCAP
McCormick Canada Inc.
McMaster University
MDA Corporation
MDS Nordion
Meloche Monnex
Meridian Technologies Inc.
Metro Richelieu
Metro Toronto Convention Centre
Michelin North America (Can) Inc.
Microsoft Canada Co.
Minacs Worldwide Inc.
Minto Developments Inc.
Miramac Mining Corporation
Molson Canada
Mountain Equipment Co-op
National Bank of Canada
National Energy Board (NEB)
NAV CANADA
NB Power Holding Corporation
Neenah Paper Company of Canada, Pictou Mill
Newalta Corporation
Nexans Canada Inc.
Nexen Inc.
North Shore Credit Union
Nova Scotia Power Inc.
Nova Scotia Public Service Commission
Office of Human Resources, Province of New Brunswick
Ontario Clean Water Agency
Ontario Municipal Employees Retirement System
Ontario Power Generation
Ontario Realty Corporation
Ontario Securities Commission
Oracle Corporation Canada Inc.
Oxford Properties Group
Panasonic Canada Inc.
Patheon Inc.
Pembina Pipeline Corporation
People First HR Services
Pepsi-QTG Canada
Petro-Canada
Petromont
Pfizer Canada Inc.
Pharmascience Inc.
Philips Electronics Ltd.
Post-Secondary Employers' Association
Potash Corporation of Saskatchewan Inc.
Prairie Agricultural Machinery Institute
Pratt and Whitney Canada
PricewaterhouseCoopers LLP
Purolator Courier Ltd.
QLT Inc.
Quebecor Media Inc.
Quixtar Canada Corporation
RBC Dexia Investor Services
RBC Financial Group
Regional Municipality of Durham
Regional Municipality of Halton
Regional Municipality of Niagara
Regional Municipality of Peel
Reitmans (Canada) Ltd.
Research In Motion
Roche Diagnostics Canada
Rogers Communications Inc.
Royal & Sun Alliance Insurance Company of Canada
Russel Metals Inc.
Ryerson University
Saint Elizabeth Health Care
SAIT Polytechnic
Sanofi-aventis Canada Inc.
Saskatchewan Government Insurance
Saskatchewan Public Service Commission
Saskatchewan Research Council
Saskatchewan Transportation Company
Saskatchewan Workers' Compensation Board
SaskEnergy Incorporated
Saskferco Products Inc.
SaskTel
Schneider Electric Canada
Scotiabank
Securit

Shell Canada Limited
Sherritt International Corp.
SIAST (Saskatchewan Institute of Applied Science and Technology)
Signature Vacations
SNC-Lavalin
Spectra Energy Gas Transmission
Standard Aero Ltd.
Stantec Inc.
St. Lawrence Cement
STM (Société de Transport de Montréal)
Strathcona County
Strathcona Paper
Suncor Energy Inc.
Sun Rich Fresh Foods Inc.
Sun-Rype
Symcor Inc.
Syncrude Canada Ltd.
Sysco Food Services of Canada Inc.
Taiga Building Products Ltd.
Talisman Energy Inc.
Tarion Warranty Corporation
TD Bank Financial Group
Teck Cominco Limited
Teknion Corporation
The Cumis Group
The Dominion of Canada General Insurance Co.
The Economical Insurance Group
The Equitable Life Insurance Company of Canada
The Law Society of Upper Canada
The Lowe-Martin Group
The TDL Group Corp. (Tim Hortons)
Thomson Carswell
Toronto Central Community Care Access Centre
Toronto Transit Commission
Torys LLP
Town of Banff
Town of Markham
TransCanada PipeLines Limited
Treasury Board Secretariat
Troy Sprinkler Ltd.
TSX Group Inc.
Ultramar Ltd.
University of Alberta
University of Calgary
University of New Brunswick
University of Regina
University of Saskatchewan
University of Toronto
UPS
VanCity Credit Union
Vancouver Coastal Health
Vancouver Public Library
Vansco Electronics LP
Velan Inc.
Wal-Mart Stores Inc.
WCB (Workers' Compensation Board)—Alberta
Wells Fargo Financial
West Fraser Timber Co. Ltd.
Winners Merchants International LP
Wrigley Canada
Xerox Canada Limited
Xstrata Nickel
Zurich Canada

APPENDIX C

Related Products and Services

Proceedings from the 2007 Compensation and Human Resources Outlook Conferences

These conferences provide a detailed look at the year ahead and give the benchmarks you need to ensure your compensation strategies remain competitive.

Compensation of Boards of Directors, 17th Edition

The 17th edition of the report summarizes the results of The Conference Board of Canada's biennial survey on the compensation received by directors for board and committee service during 2006.

The Strategic Value of People: Human Resource Trends and Metrics

This inaugural report presents results from a 2005 survey of Canadian human resource management trends and metrics. It presents benchmark data and analysis, and a talent management framework to focus measurement.

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Interact with senior compensation and human resources executives from major Canadian organizations. Gain access to independent, objective, leading-edge research into key compensation, industrial relations and human resources management issues.

Council of Industrial Relations Executives

This network will provide you with insights to assist you in leading the labour relations function in your organization. It is only open to employers and members have responsibility for several large bargaining units, and they often operate in multiple legal jurisdictions.

Councils of Human Resource Executives (National, East, West)

Interact with senior HR executives responsible for the Canadian operations of large organizations. Learn from experts, and discuss issues that support HR management strategy and key operating decisions.

Canadian Centre for Learning and Development

Examine best policies and practices in corporate training and education, learning, human resources and organizational development.

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Improve the strategic and competitive position of your organization by adopting the most effective management and leadership practices. Build insight into leading organizations' practice in human resource and organizational development.

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1. Inflation

a) Introduction

The forecast British Columbia CPI is used as a cost driver for aspects of the cost of service because it is widely regarded as a reasonable measure of the forecast inflation applicable to the Province. The CPI is generally used to index wages, salaries, pension, and various other expenses.

b) Review History Highlights (2003-2009 Actuals)

Pursuant to the provisions of the Settlement Agreements (Order No. G-51-03 and Order No. G-33-07), the B.C. CPI inflation forecast was determined as the average of the forecasts from four reputable industry sources: Conference Board of Canada, B.C. Ministry of Finance, RBC Financial Group and the Toronto-Dominion Bank. In addition to the forecast CPI, and also in accordance with the Settlement Agreements, an adjustment factor was applied to the B.C. CPI to arrive at the inflation applied the formula operating and maintenance expense and formula capital additions throughout the PBR period. The following table provides a summary of the B.C. CPI and the adjusted CPI embedded in the revenue requirements from 2003-2009:

Table 1- Appendix 24: Historic B.C. CPI and TGI Adjustment Factors (2004-2009)

	2004	2005	2006	2007	2008	2009
CPI	1.70%	2.00%	2.20%	2.00%	2.00%	2.10%
Adjustment Factor	-0.85%	-1.00%	-1.45%	-1.32%	-1.32%	-1.39%
Adjusted CPI	0.85%	1.00%	0.75%	0.68%	0.68%	0.71%

c) Forecast Inflation

Terasen Gas has continued using the B.C. CPI as a cost driver for aspects cost of service for both 2010 and 2011. The average B.C. CPI is 1.90% for 2010 and 2.00% for 2011. The forecast used is comprised of the average of the following rates:

Source	C.P.I Forecast		Forecast Publish Date
	2010	2011	
Conference Board of Canada	2.27%	2.05%	April 2009
B.C. Ministry of Finance	2.20%	2.10%	September 2008
RBC Financial Group	1.50%	1.80%	October 2008
Toronto-Dominion Bank	1.60%	2.00%	March 2009

Attachment 1 of this appendix provides copies of the forecasts used to derive the average B.C. CPI for 2010 and 2011.

The Conference Board of Canada

Forecast Completed: Apr. 21 2009

TABLE 11: KEY ECONOMIC INDICATORS, BRITISH COLUMBIA

	2008Q1	2008Q2	2008Q3	2008Q4	2009Q1	2009Q2	2009Q3	2009Q4	2010Q1	2010Q2	2010Q3	2010Q4	2008	2009	2010
G.D.P AT MARKET PRICES	195884	199898	200281	194054	189050	189122	190855	194023	197703	199711	202403	205686	197529	190763	201375
(MILLIONS $)	-0.5	2.0	0.2	-3.1	-2.6	0.0	0.9	1.7	1.9	1.0	1.3	1.6	2.5	-3.4	5.6
	12.4	12.3	12.3	12.3	12.4	12.4	12.4	12.4	12.5	12.5	12.6	12.6	12.3	12.4	12.6
G.D.P AT BASIC PRICES	180466	184343	184755	178954	174087	174214	175800	178781	182203	183982	186388	189371	182129	175721	185486
(MILLIONS $)	-0.1	2.1	0.2	-3.1	-2.7	0.1	0.9	1.7	1.9	1.0	1.3	1.6	3.1	-3.5	5.6
	12.2	12.1	12.0	12.1	12.1	12.2	12.2	12.2	12.3	12.3	12.3	12.4	12.1	12.2	12.3
G.D.P AT BASIC PRICES	152066	152495	152100	150693	148873	148710	149015	149856	152020	153279	154596	155947	151838	149113	153960
(MILLIONS $ 2002)	0.1	0.3	-0.3	-0.9	-1.2	-0.1	0.2	0.6	1.4	0.8	0.9	0.9	0.9	-1.8	3.3
	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.5	12.5	12.5	12.5	12.4	12.4	12.5
CONSUMER PRICE INDEX (2002=1.0)	1.103	1.127	1.141	1.122	1.118	1.127	1.134	1.141	1.148	1.154	1.162	1.170	1.123	1.130	1.158
	0.2	2.2	1.2	-1.7	-0.4	0.8	0.6	0.6	0.5	0.6	0.6	0.7	2.1	0.6	2.5
IMPLICIT PRICE DEFLATOR -	1.187	1.209	1.215	1.188	1.169	1.172	1.180	1.193	1.199	1.200	1.206	1.214	1.199	1.178	1.205
GDP AT BASIC PRICES (2002=1.0)	-0.2	1.9	0.5	-2.2	-1.5	0.2	0.7	1.1	0.5	0.1	0.4	0.7	2.1	-1.8	2.2
AVERAGE WEEKLY WAGE	748	750	755	752	755	755	758	763	770	775	780	786	751	758	778
($, INDUSTRIAL COMPOSITE)	-0.2	0.3	0.6	-0.4	0.5	-0.0	0.4	0.6	0.9	0.7	0.7	0.7	1.5	0.9	2.6
PERSONAL INCOME (MILLIONS $)	158467	158883	159630	160414	159760	160570	161595	163313	165367	167025	168996	170738	159348	161309	168031
	2.2	0.3	0.5	0.5	-0.4	0.5	0.6	1.1	1.3	1.0	1.2	1.0	4.9	1.2	4.2
	13.0	13.0	13.0	13.0	13.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.0	13.1	13.1
PERSONAL DISPOSABLE INCOME	123564	124598	125502	126033	125688	126481	127314	128674	130174	131643	133147	134422	124924	127039	132347
(MILLIONS $)	2.9	0.8	0.7	0.4	-0.3	0.6	0.7	1.1	1.2	1.1	1.1	1.0	6.5	1.7	4.2
	13.1	13.1	13.1	13.1	13.2	13.2	13.2	13.3	13.3	13.3	13.3	13.3	13.1	13.2	13.3
PERSONAL SAVINGS RATE	-3.2	-3.5	-3.4	-1.3	-0.8	-1.5	-1.9	-2.0	-1.7	-1.3	-1.1	-0.9	-2.8	-1.6	-1.2
	-40.4	-8.8	2.8	61.0	40.0	-93.7	-24.1	-6.6	16.3	23.7	16.0	19.0	-43.9	45.0	20.6
POPULATION OF LABOUR	3615	3633	3652	3668	3681	3686	3694	3711	3734	3747	3760	3773	3642	3693	3753
FORCE AGE	0.5	0.5	0.5	0.4	0.4	0.1	0.2	0.5	0.6	0.4	0.4	0.4	2.0	1.4	1.6
	13.5	13.5	13.5	13.5	13.6	13.5	13.5	13.5	13.6	13.6	13.6	13.6	13.5	13.5	13.6
LABOUR FORCE ('000s)	2412	2429	2431	2432	2420	2424	2432	2450	2467	2478	2488	2496	2426	2431	2482
	0.9	0.7	0.1	0.1	-0.5	0.2	0.3	0.7	0.7	0.4	0.4	0.3	2.5	0.2	2.1
	13.3	13.3	13.3	13.3	13.2	13.3	13.3	13.3	13.4	13.4	13.4	13.4	13.3	13.3	13.4
EMPLOYMENT ('000s)	2310	2320	2320	2306	2257	2254	2249	2256	2261	2270	2280	2292	2314	2254	2276
	0.8	0.4	0.0	-0.6	-2.1	-0.1	-0.2	0.3	0.3	0.4	0.4	0.6	2.1	-2.6	1.0
	13.5	13.5	13.5	13.5	13.3	13.4	13.4	13.5	13.5	13.5	13.5	13.5	13.5	13.4	13.5
UNEMPLOYMENT RATE	4.2	4.5	4.5	5.2	6.7	7.0	7.5	7.9	8.3	8.4	8.4	8.1	4.6	7.3	8.3
RETAIL SALES (MILLIONS $)	57403	57478	57136	53993	51797	53280	53917	54660	55152	55717	56285	56862	56502	53414	56004
	0.0	0.1	-0.6	-5.5	-4.1	2.9	1.2	1.4	0.9	1.0	1.0	1.0	0.3	-5.5	4.8
	13.5	13.4	13.2	13.0	12.9	13.0	13.0	13.1	13.1	13.1	13.1	13.1	13.3	13.0	13.1
HOUSING STARTS (NUMBER OF UNITS)	39176	37863	34955	25290	17708	19077	20546	20751	21374	22336	23341	24568	34321	19521	22905
	-7.8	-3.4	-7.7	-27.7	-30.0	7.7	7.7	1.0	3.0	4.5	4.5	5.3	-12.4	-43.1	17.3
	16.7	17.4	16.9	13.7	12.3	13.6	14.3	13.6	13.4	13.7	13.8	14.1	16.3	13.5	13.8

Sources: Statistics Canada, CMHC, The Conference Board of Canada.

The Conference Board of Canada
Forecast Completed: Apr. 21 2009

TABLE 11: KEY ECONOMIC INDICATORS, BRITISH COLUMBIA

	2011Q1	2011Q2	2011Q3	2011Q4	2012Q1	2012Q2	2012Q3	2012Q4	2013Q1	2013Q2	2013Q3	2013Q4	2011	2012	2013
G.D.P AT MARKET PRICES	210191	213657	218196	222245	226541	230423	234378	238076	241620	244946	248056	251111	216072	232354	246433
(MILLIONS $)	2.2	1.6	2.1	1.9	1.9	1.7	1.7	1.6	1.5	1.4	1.3	1.2	7.3	7.5	6.1
	12.6	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
G.D.P AT BASIC PRICES	193564	196612	200842	204588	208566	212148	215803	219207	222454	225486	228304	231067	198901	213931	226828
(MILLIONS $)	2.2	1.6	2.2	1.9	1.9	1.7	1.7	1.6	1.5	1.4	1.2	1.2	7.2	7.6	6.0
	12.4	12.4	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.4	12.5	12.5
G.D.P AT BASIC PRICES	157482	158982	160608	162255	164251	165880	167473	168969	170424	171799	173117	174374	159832	166643	172428
(MILLIONS $ 2002)	1.0	1.0	1.0	1.0	1.2	1.0	1.0	0.9	0.9	0.8	0.8	0.7	3.8	4.3	3.5
	12.5	12.5	12.5	12.5	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.5	12.4	12.4
CONSUMER PRICE INDEX (2002=1.0)	1.178	1.185	1.191	1.197	1.205	1.211	1.218	1.224	1.230	1.238	1.244	1.251	1.188	1.214	1.241
	0.7	0.6	0.5	0.5	0.6	0.5	0.6	0.5	0.6	0.6	0.5	0.5	2.6	2.2	2.2
IMPLICIT PRICE DEFLATOR -	1.229	1.237	1.251	1.261	1.270	1.279	1.289	1.297	1.305	1.312	1.319	1.325	1.244	1.284	1.315
GDP AT BASIC PRICES (2002=1.0)	1.2	0.6	1.1	0.8	0.7	0.7	0.8	0.7	0.6	0.6	0.5	0.5	3.3	3.2	2.5
AVERAGE WEEKLY WAGE	791	797	802	808	813	819	825	831	838	844	850	856	799	822	847
($, INDUSTRIAL COMPOSITE)	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.7	0.7	0.6	2.8	2.9	3.0
PERSONAL INCOME (MILLIONS $)	173014	174856	177544	179949	182421	184535	186817	188820	191360	193452	195545	197662	176341	185648	194505
	1.3	1.1	1.5	1.4	1.4	1.2	1.2	1.1	1.3	1.1	1.1	1.1	4.9	5.3	4.8
	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1
PERSONAL DISPOSABLE INCOME	136072	137109	139143	140951	142652	144206	145942	147467	149265	150854	152459	154089	138319	145067	151667
(MILLIONS $)	1.2	0.8	1.5	1.3	1.2	1.1	1.2	1.0	1.2	1.1	1.1	1.1	4.5	4.9	4.5
	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.2	13.2	13.2	13.3	13.3	13.2
PERSONAL SAVINGS RATE	-0.9	-1.4	-1.6	-1.8	-2.2	-2.5	-2.9	-3.1	-3.3	-3.5	-3.8	-4.0	-1.4	-2.7	-3.6
	1.3	-66.3	-8.6	-15.1	-20.6	-16.6	-12.9	-10.2	-5.1	-7.0	-6.7	-5.3	-14.7	-88.8	-36.4
POPULATION OF LABOUR	3786	3800	3813	3826	3839	3852	3865	3878	3891	3904	3916	3929	3806	3858	3910
FORCE AGE	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	1.4	1.4	1.3
	13.6	13.6	13.6	13.6	13.6	13.6	13.7	13.7	13.7	13.7	13.7	13.7	13.6	13.6	13.7
LABOUR FORCE ('000s)	2506	2517	2525	2534	2541	2547	2556	2563	2566	2573	2580	2587	2520	2552	2577
	0.4	0.4	0.3	0.4	0.3	0.3	0.4	0.2	0.1	0.3	0.3	0.3	1.6	1.2	1.0
	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4
EMPLOYMENT ('000s)	2304	2321	2346	2366	2382	2393	2406	2414	2424	2432	2442	2452	2334	2399	2438
	0.5	0.8	1.1	0.9	0.7	0.5	0.6	0.3	0.4	0.3	0.4	0.4	2.6	2.8	1.6
	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
UNEMPLOYMENT RATE	8.1	7.8	7.1	6.6	6.3	6.1	5.9	5.8	5.5	5.5	5.3	5.2	7.4	6.0	5.4
RETAIL SALES (MILLIONS $)	57817	58771	59887	60919	61977	62940	63969	64870	65788	66614	67455	68272	59349	63439	67032
	1.7	1.7	1.9	1.7	1.7	1.6	1.6	1.4	1.4	1.3	1.3	1.2	6.0	6.9	5.7
	13.1	13.1	13.1	13.1	13.1	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.1	13.0	13.0
HOUSING STARTS (NUMBER OF UNITS)	29579	30272	31033	31174	31290	31869	31840	31306	31088	30777	30408	30104	30515	31576	30594
	20.4	2.3	2.5	0.5	0.4	1.9	-0.1	-1.7	-0.7	-1.0	-1.2	-1.0	33.2	3.5	-3.1
	16.3	16.2	16.4	16.3	16.1	16.2	16.2	15.9	15.8	15.7	15.5	15.2	16.3	16.1	15.5

Sources: Statistics Canada, CMHC, The Conference Board of Canada.

Table 2.7.2 Components of Nominal Income and Expenditure

	2006	2007	Forecast 2008	2009	2010	2011	2012
Labour income[1] ($ million)	93,102	98,866	105,292	110,282	115,486	120,857	126,463
(% change)	8.5	6.2	6.5	4.7	4.7	4.7	4.6
Personal income ($ million)	141,098	150,379	158,659	165,526	173,046	180,919	189,202
(% change)	7.4	6.6	5.5	4.3	4.5	4.5	4.6
Corporate profits before taxes ($ million)	21,322	20,886	20,555	20,897	21,794	22,773	23,814
(% change)	6.7	-2.0	-1.6	1.7	4.3	4.5	4.6
Retail sales ($ million)	52,837	56,365	58,157	60,894	63,866	67,013	70,221
(% change)	7.2	6.7	3.2	4.7	4.9	4.9	4.8
Housing starts	36,443	39,195	37,092	32,933	31,519	31,071	30,650
(% change)	5.1	7.6	-5.4	-11.2	-4.3	-1.4	-1.4
Residential investment[2] ($ million)	17,191	19,223	20,175	20,338	21,150	22,184	23,227
(% change)	16.5	11.8	5.0	0.8	4.0	4.9	4.7
BC consumer price index (2001 = 100)	108.1	110.0	112.5	114.7	117.2	119.7	122.2
(% change)	1.7	1.8	2.2	2.0	2.1	2.1	2.1

[1] Domestic basis; wages, salaries and supplementary labour income.

[2] Includes renovations and improvements.

Table 2.7.3 Labour Market Indicators

	2006	2007	Forecast 2008	2009	2010	2011	2012
Population (on July 1) (000's)	4,320	4,380	4,440	4,498	4,558	4,619	4,680
(% change)	1.4	1.4	1.4	1.3	1.3	1.3	1.3
Labour force population, 15+ Years (000's)	3,511	3,571	3,639	3,698	3,757	3,815	3,871
(% change)	1.8	1.7	1.9	1.6	1.6	1.6	1.5
Net in-migration (000's)							
– International[1]	38.1	39.6	36.2	37.3	38.4	39.4	38.3
– Interprovincial	10.2	13.4	9.0	11.0	12.0	13.0	13.0
– Total	48.3	53.0	45.2	48.3	50.4	52.4	51.3
Participation rate[2] (%)	65.7	66.3	66.8	66.8	66.9	67.1	67.2
Labour force (000's)	2,305	2,366	2,431	2,471	2,515	2,559	2,603
(% change)	1.8	2.7	2.7	1.6	1.8	1.8	1.7
Employment (000's)	2,196	2,266	2,323	2,362	2,402	2,440	2,479
(% change)	3.1	3.2	2.5	1.7	1.7	1.6	1.6
Unemployment rate (%)	4.8	4.2	4.4	4.4	4.5	4.6	4.8

[1] International migration includes net non-permanent residents and returning emigrants less net temporary residents abroad.

[2] Percentage of the population 15 years of age and over in the labour force.

RBC®

NEWS

BRITISH COLUMBIA IN THE MIDST OF A PROSPEROUS DECADE, SAYS RBC

TORONTO, July 3, 2008 — British Columbia's economy continues to trend above the national average, although further weakness in its exports is expected to restrain growth to 2.2 per cent in 2008 and 2.9 per cent in 2009, according to a provincial economic outlook released today by RBC.

"The current decade has proven to be very prosperous for British Columbia as 2007 marked the sixth consecutive year of economic growth above of the national average and we expect this trend to continue right through to 2010," said Craig Wright, senior vice-president and chief economist, RBC. "However, the challenges facing the province's exporters are many and do not appear to be letting up, particularly with respect to the rout in the U.S. housing construction sector."

According to the report, wood products are leading five of the top six export categories showing declines so far this year, with only the energy sector garnering a gain. Nevertheless, the province's strong domestic economy continues to adequately compensate for the trade sector slump and should help to keep British Columbia among the provincial growth leaders in Canada. However, signs of cooling are emerging domestically as well. Housing resale activity has levelled off and housing starts are forecast to soften over the course of the next two years. Growth in non-residential construction appears to be peaking. Consumer spending is on course to a slower pace as the momentum generated by the recent run-up in employment and steady decline in the unemployment rate starts to fade.

The main theme of the Provincial Outlook continues to be the different paths the Eastern and Western parts of the country are taking. Record-high commodity prices and strong global demand for resources sustain unprecedented prosperity in the Western provinces, while the strong Canadian dollar, downturn in the U.S. economy and high energy prices continue to cause hardship in key sectors in provinces east of Manitoba. Saskatchewan is projected to lead all of the provinces in economic growth for both 2008 and 2009, followed by Alberta, while Newfoundland and Labrador and Ontario are expected to lag the group this year, but should show some improvement next year.

- more -

The RBC Economics Provincial Outlook assesses the provinces according to economic growth, employment growth, unemployment rates, personal income growth, retail sales, housing starts, and the Consumer Price Index.

According to the report (available online as of 8 a.m. E.D.T., at www.rbc.com/economics/market/pdf/provfcst.pdf), provincial forecast details are as follows:

	Real GDP			Housing starts Thousands			Retail sales			Employment			CPI		
	07	**08**	**09**	**07**	**08**	**09**	**07**	**08**	**09**	**07**	**08**	**09**	**07**	**08**	**09**
NFLD.	**9.1**	**0.2**	**1.3**	**2.6**	**2.6**	**2.0**	**8.9**	**6.0**	**2.0**	**0.6**	**2.0**	**0.5**	**1.5**	**2.5**	**1.4**
P.E.I	**2.0**	**1.2**	**1.6**	**0.8**	**0.7**	**0.6**	**7.7**	**4.5**	**3.7**	**1.0**	**1.3**	**0.3**	**1.8**	**3.2**	**1.5**
N.S.	**1.6**	**2.0**	**2.4**	**4.8**	**4.7**	**4.0**	**4.2**	**5.5**	**4.5**	**1.3**	**1.0**	**1.9**	**1.9**	**3.0**	**1.6**
N.B.	**1.6**	**2.0**	**2.5**	**4.2**	**4.2**	**3.4**	**5.7**	**4.6**	**4.0**	**2.1**	**1.6**	**1.0**	**1.9**	**1.8**	**1.5**
QUE.	**2.4**	**1.0**	**2.3**	**48.6**	**47.1**	**40.0**	**4.6**	**4.3**	**4.4**	**2.3**	**1.4**	**1.3**	**1.6**	**2.2**	**1.4**
ONT.	**2.1**	**0.7**	**2.2**	**68.1**	**68.7**	**59.3**	**3.9**	**4.4**	**4.5**	**1.6**	**1.5**	**1.3**	**1.8**	**2.0**	**1.5**
MAN.	**3.3**	**2.7**	**2.7**	**5.7**	**5.9**	**4.5**	**8.8**	**8.5**	**7.0**	**1.6**	**2.1**	**1.7**	**2.0**	**2.0**	**1.5**
SASK.	**2.8**	**3.7**	**3.8**	**6.0**	**6.6**	**4.5**	**13.0**	**12.0**	**11.0**	**2.1**	**2.4**	**2.3**	**2.8**	**3.4**	**2.6**
ALTA.	**3.3**	**3.1**	**3.0**	**48.3**	**38.3**	**35.1**	**9.3**	**4.5**	**7.0**	**4.7**	**3.0**	**2.1**	**5.0**	**3.3**	**2.5**
B.C.	**3.1**	**2.2**	**2.9**	**39.2**	**37.2**	**30.5**	**6.7**	**4.5**	**7.5**	**3.2**	**2.6**	**2.5**	**1.8**	**2.0**	**1.5**
CANADA	**2.7**	**1.4**	**2.5**	**228**	**216**	**184**	**5.8**	**5.2**	**5.6**	**2.3**	**1.9**	**1.6**	**2.1**	**2.3**	**1.6**

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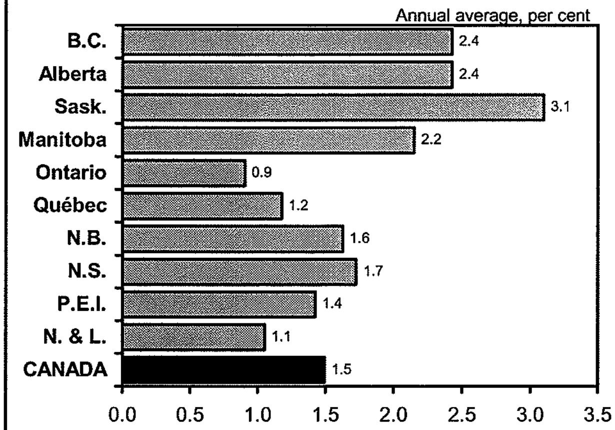
REAL GROSS DOMESTIC PRODUCT (GDP) Annual average per cent change						
	97-06	2005	2006	2007E	2008F	2009F
CANADA	**3.5**	**3.1**	**2.8**	**2.7**	**1.1**	**1.8**
N. & L.	4.4	0.4	3.3	8.0	1.0	1.2
P.E.I.	2.4	2.1	2.6	1.9	1.3	1.6
N.S.	2.9	1.6	0.9	2.0	1.5	2.0
N.B.	2.6	0.3	3.0	2.3	1.1	2.2
Québec	2.9	2.2	1.7	2.0	1.0	1.4
Ontario	3.7	2.8	2.1	1.9	0.5	1.3
Manitoba	2.7	2.7	3.2	3.0	2.0	2.3
Sask.	2.0	3.1	-0.4	3.9	3.2	3.0
Alberta	4.2	4.6	6.6	4.4	2.1	2.8
B.C.	3.0	4.5	3.4	3.2	2.2	2.7

E: Estimate; F: Forecast by TD Economics as at April 2008.
Source: Statistics Canada

REAL GDP GROWTH FORECAST* 2008-09



* Forecast by TD Economics as at April 2008.

EMPLOYMENT Annual average per cent change						
	98-07	2005	2006	2007	2008F	2009F
CANADA	**2.1**	**1.4**	**1.9**	**2.3**	**1.5**	**0.6**
N. & L.	1.5	-0.1	0.7	0.7	1.0	0.8
P.E.I.	1.7	2.0	0.5	1.2	0.9	0.4
N.S.	1.6	0.2	-0.3	1.3	1.3	0.6
N.B.	1.6	0.1	1.4	2.1	1.0	1.3
Québec	2.0	1.0	1.3	2.3	1.2	0.3
Ontario	2.2	1.3	1.5	1.5	1.0	0.4
Manitoba	1.3	0.6	1.2	1.6	1.9	0.7
Sask.	0.7	0.8	1.7	2.1	1.9	1.4
Alberta	3.0	1.5	4.8	4.7	2.7	1.5
B.C.	2.0	3.3	3.0	3.2	2.1	1.2

F: Forecast by TD Economics as at April 2008
Source: Statistics Canada.

UNEMPLOYMENT RATE Annual average, per cent						
	98-07	2005	2006	2007	2008F	2009F
CANADA	**7.1**	**6.8**	**6.3**	**6.0**	**6.0**	**6.3**
N. & L.	16.0	15.2	14.8	13.6	11.9	11.4
P.E.I.	11.9	10.9	11.1	10.3	9.8	9.7
N.S.	9.1	8.5	7.9	8.1	7.1	7.1
N.B.	10.0	9.7	8.7	7.6	8.0	7.8
Québec	8.7	8.3	8.0	7.2	7.2	7.6
Ontario	6.6	6.6	6.3	6.4	6.6	7.0
Manitoba	5.0	4.8	4.3	4.4	3.7	4.1
Sask.	5.3	5.1	4.6	4.2	3.6	3.9
Alberta	4.7	3.9	3.4	3.5	3.3	3.6
B.C.	7.1	5.9	4.8	4.2	4.2	4.9

F: Forecast by TD Economics as at April 2008
Source: Statistics Canada.

TOTAL CONSUMER PRICE INDEX Annual average per cent change						
	98-07	2005	2006	2007	2008F	2009F
CANADA	**2.1**	**2.2**	**2.0**	**2.1**	**1.5**	**1.9**
N. & L.	1.9	2.6	1.8	1.4	1.4	1.8
P.E.I.	2.3	3.2	2.2	1.8	1.6	2.1
N.S.	2.3	2.8	2.1	1.9	2.1	2.2
N.B.	2.1	2.4	1.7	1.9	1.3	1.7
Québec	2.0	2.3	1.7	1.6	1.3	1.7
Ontario	2.1	2.2	1.8	1.8	1.4	1.9
Manitoba	2.0	2.7	1.9	2.1	1.6	2.0
Sask.	2.3	2.2	2.0	2.9	3.2	3.0
Alberta	3.0	2.1	3.9	4.9	2.8	2.5
B.C.	1.7	2.0	1.7	1.7	1.2	1.7

F: Forecast by TD Economics as at April 2008.
Source: Statistics Canada.

RETAIL TRADE Annual average per cent change						
	98-07	2005	2006	2007	2008F	2009F
CANADA	**5.3**	**5.6**	**6.4**	**5.8**	**4.0**	**4.8**
N. & L.	5.3	1.2	3.7	9.5	3.6	2.9
P.E.I.	4.5	2.8	4.0	8.2	3.4	4.5
N.S.	4.1	2.2	6.3	4.0	3.9	4.4
N.B.	4.8	4.6	6.1	6.2	4.1	4.5
Quebec	4.9	5.1	5.1	4.3	3.0	3.6
Ontario	4.9	4.8	4.1	4.0	2.0	3.4
Manitoba	5.2	5.9	4.5	9.5	5.0	6.1
Sask.	5.3	5.2	6.5	12.9	8.4	6.0
Alberta	8.5	11.8	15.6	9.0	7.6	7.2
B.C.	4.5	4.4	6.8	7.2	6.3	6.8

F: Forecast by TD Economics as at April 2008
Source: Statistics Canada

EARNED RETURN HISTORY

Utility Income and Earned Return 2003-2008

TERASEN GAS INC.
UTILITY INCOME AND EARNED RETURN
($000)

Line No.	Description	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual
1	**ENERGY VOLUMES (TJ)**						
2	Sales	112,849	109,231	112,117	110,214	120,227	125,239
3	Transportation	96,719	101,697	99,923	98,708	101,295	96,677
4	Total	209,568	210,928	212,040	208,922	221,522	221,916
5							
6	**AVERAGE RATE PER GJ**						
7	Sales	$10.428	$10.862	$12.014	$12.770	$11.961	$12,724
8	Transportation	$0.660	$0.666	$0.728	$0.770	$0.735	$0.786
9	Average	$5.920	$5.946	$6.695	$7.101	$6.828	$7.523
10							
11	**UTILITY REVENUE**						
12	Sales - Present Rates	$ 1,176,818	$ 1,186,495	$ 1,347,001	$ 1,407,469	$ 1,438,081	$ 1,593,531
13	- Decrease	-	-	-	-	-	-
14	Transportation - Present Rates	63,809	67,701	72,707	75,990	74,461	76,001
15	- Decrease	-	-	-	-	-	-
16	**Total Revenue**	1,240,627	1,254,196	1,419,708	1,483,459	1,512,542	1,669,532
17							
18	Cost of Gas Sold (Including Gas Lost)	801,608	803,694	956,894	1,004,872	1,016,561	1,153,063
19	**Gross Margin**	439,019	450,502	462,814	478,587	495,981	516,469
20	RSAM Revenue	29,655	22,916	15,699	14,148	(9,801)	(25,175)
21	**Adjusted Gross Margin**	468,674	473,418	478,513	492,735	486,180	491,294
22							
23	Operation & Maintenance	140,963	153,497	142,710	150,223	149,564	156,208
24	Operating Leases	6,405	6,405	1,911	1,872	2,008	1,988
25	Property Tax	41,213	39,420	39,573	41,379	44,452	44,635
26	Franchise Fees	-	-	-	-	-	-
27	Depreciation and Amortization	72,391	77,233	76,176	80,466	75,261	74,876
28	Other Operating Revenue	(20,811)	(20,134)	(23,255)	(22,696)	(22,044)	(21,834)
29		240,161	256,421	237,115	251,244	249,241	255,873
30	Utility Income before Income Taxes	228,513	216,997	241,398	241,491	236,939	235,421
31	Income Taxes	44,509	41,401	44,158	44,439	37,599	32,656
32	**EARNED RETURN**	$ 184,004	$ 175,596	$ 197,240	$ 197,052	$ 199,340	$ 202,765
33	**UTILITY RATE BASE**	$ 2,249,535	$ 2,306,704	$ 2,408,090	$ 2,442,636	$ 2,425,545	$ 2,471,877
34							
35	**RETURN ON RATE BASE**	8.18%	7.61%	8.19%	8.07%	8.22%	8.20%

TERASEN GAS INC.
UTILITY INCOME AND EARNED RETURN
($000)

Line No.	Description	2003 Normal	2004 Normal	2005 Normal	2006 Normal	2007 Normal	2008 Normal
1	ENERGY VOLUMES (TJ)						
2	Sales	120,381	117,994	112,749	112,775	114,028	112,010
3	Transportation	98,474	101,997	99,531	96,302	100,791	98,081
4	Total	218,854	219,991	212,280	209,077	214,819	210,091
5							
6	AVERAGE RATE PER GJ						
7	Sales	$10.296	$10.792	$11.939	$12.774	$11.989	$12.548
8	Transportation	$0.643	$0.661	$0.729	$0.768	$0.644	$0.746
9	Average	$5.953	$6.095	$6.683	$7.244	$6.666	$7.038
10							
11	UTILITY REVENUE						
12	Sales - Present Rates	$ 1,239,409	$ 1,273,413	$ 1,346,138	$ 1,440,644	$ 1,367,086	$ 1,405,491
13	- Decrease	-	-	-	-	-	-
14	Transportation - Present Rates	63,361	67,461	72,597	73,919	64,912	73,168
15	- Decrease	-	-	-	-	-	-
16	Total Revenue	1,302,770	1,340,875	1,418,735	1,514,563	1,431,998	1,478,659
17							
18	Cost of Gas Sold (Including Gas Lost)	846,499	867,678	952,643	1,029,444	963,275	997,718
19	Gross Margin	456,271	473,196	466,092	485,119	468,723	480,941
20	RSAM Revenue	14,414	1,470	14,605	9,901	7,775	12,967
21	Adjusted Gross Margin	470,685	474,666	480,697	495,020	476,498	493,908
22							
23	Operation & Maintenance	140,963	153,497	142,710	150,223	149,564	156,208
24	Operating Leases	6,405	6,405	1,911	1,872	2,008	1,988
25	Property Tax	41,213	39,420	39,573	41,379	44,452	44,635
26	Franchise Fees	-	-	-	-	-	-
27	Depreciation and Amortization	72,391	77,233	76,176	80,466	75,261	74,876
28	Other Operating Revenue	(20,811)	(20,134)	(23,255)	(22,696)	(22,044)	(21,834)
29		240,161	256,421	237,115	251,244	249,241	255,873
30	Utility Income before Income Taxes	230,524	218,245	243,582	243,776	227,257	238,035
31	Income Taxes	45,253	41,846	44,895	45,197	34,402	33,451
32	EARNED RETURN	$ 185,271	$ 176,399	$ 198,687	$ 198,579	$ 192,855	$ 204,584
33	UTILITY RATE BASE	$ 2,248,843	$ 2,305,591	$ 2,408,116	$ 2,442,352	$ 2,426,180	$ 2,474,447
34							
35	RETURN ON RATE BASE	8.24%	7.65%	8.25%	8.13%	7.95%	8.27%

Natural Gas Markets

Workforce Demographics: Addressing An Aging Workforce in the Natural Gas Distribution Sector

Fall 2007

Natural gas utilities, like all industries in Canada, are faced with the challenge of an aging workforce population. This document summarizes the current workforce demographics within this sector, compares the demographic challenges it faces to other industries and similar sectors, and outlines the various factors driving this issue. Some of the strategies and "best practices" that can help address this issue are also outlined.

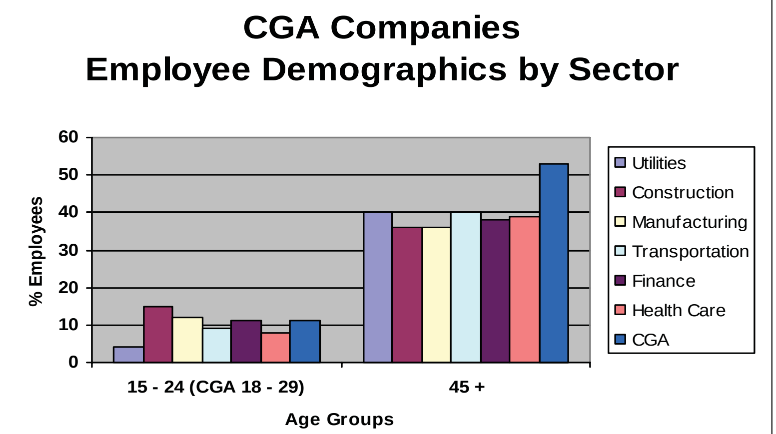
Workforce Demographics Are Changing

The age of Canada's workforce population is increasing. For the natural gas utility sector this is happening at a greater rate over a shorter period of time.

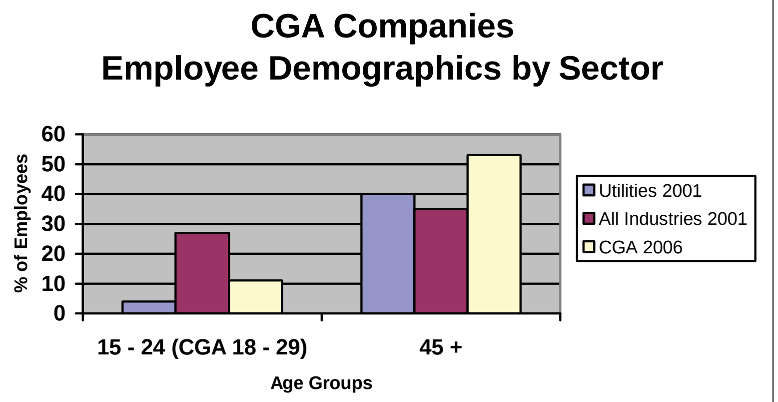
According to Statistics Canada, the median age of Canada's general working population reached 41 years in 2001, up from 38 years in the early 1990's. By the year 2011, the median age is expected to reach a high of 43.7 years.

Human Resources Canada estimates indicate that by 2011, 41% of the working age population will be between the age of 45 and 64, up from 29% in 1991.

Interestingly, the degree or impact of an aging workforce is not uniform across all industries. The Canadian Labour and Business Centre concluded that for natural gas utilities the outlook is quite different. Currently, 52.9% of the workforce is 45 years of age or older. This compares to approximately 34% for all industries and 40% for the entire "utilities industry". For the purposes of this document, the "utilities industry" is defined as: municipally owned and private electric power generation, transmission and distribution; natural gas distribution; and, water, sewage and other systems.



(Sector Data - most recent published census data)



(Sector Data - most recent published census data)

Factors Driving Change

There are a number of factors influencing these unprecedented changes in workforce demographics. In general, while all Canadian industries are feeling the impact of these factors, evidence shows that natural gas utilities are being affected to a greater degree.

Qualified young workers are in decline

There are limited numbers of qualified young workers currently employed across all industries with the Utilities industry, and in particular natural gas utilities, having the lowest proportion of youth. The percent of the workforce between 15 and 29 years of age currently employed by natural gas utilities is 10.7%. This compares to 17.4% among all industries and 3.1% for the Utilities industry between 15 and 24 years of age.

There is a future shortage of younger workers

Canada's birth rate has remained below the rate of employee population replacement for more than thirty years. The current fertility rate is at its lowest ever at 1.5 children per woman. In addition to having fewer qualified younger workers among the existing workforce, there is expected to be an overall shortage of available younger replacement workers in the future.

Workers are retiring at a younger age

Across all industries over the past ten years, Canadians are retiring at a younger age than in the past. This is particularly true for the utilities sector.

For the utilities sector, the median age of retirement dropped from 59.1 years of age between 1991 and 1995, to 56.6 years of age between 1996 and 2000. This compares to a median age of retirement of 61 years among all industries.

It is an increasingly competitive job market

An increase in retirements from the workforce and a slowing of labour force growth is further impacted by strong economic growth in Canada. With Canada's jobless rate at approximately 6.1%, the lowest it has been in thirty years, competition for labour is high across the country and some provinces are experiencing labour shortages more than others. For example, in Alberta a shortage of both skilled and unskilled workers is a critical issue as the province faces a historic low jobless rate of 3.5%.

Members of the Canadian Gas Association have identified several strategies to address the aging workforce population within natural gas utilities to ensure a continued highly skilled workforce. In addition to these strategies, natural gas utilities continue to share specific best practices associated with workforce planning, succession planning, attraction, recruitment and training.

Attracting, Integrating, and Retaining New Employees

There are three categories of potential new entrants to the labour force available to natural gas utilities. Each requires targeted attraction, integration and retention strategies that, to be successful, will require more resources than in the past.

Develop strategies to attract and retain young workers

In an increasingly competitive job market, natural gas utilities should develop strategies to attract and retain quality young people. These strategies should recognize two key factors:

- The earlier potential young employees are exposed to opportunities and experiences in the natural gas industry, in a way that recognizes their needs, the greater the chances are that they will be attracted to careers in the industry.
- Studies have shown that Canadian workers in the 18-29 age group are attracted by employer packages that offer a combination of competitive compensation, career development opportunities and support for a positive work/life balance.

Develop strategies to attract recent immigrants as a key source of skilled labour

Over the past decade, recent immigrants have accounted for 70% of Canada's net labour force growth and within 25 years immigration will be the only source of net population growth. A large portion of immigrant arrivals to Canada – 61% between 2000 and 2002 – are defined as well-educated and have at least one year of full-time work experience in a managerial, professional, technical or other skilled occupation. Within this category of immigrants, over 90% have post-secondary education credentials. The types of education are of particular value to the energy industry, as 43% are more likely to have majored in the physical sciences, engineering and trades than the Canadian born population (33%).

Given this source of skilled labour, natural gas utilities support:

- The process being led by the federal government to recognize foreign credentials to ensure that immigrants are fully able to use their skills and that employers are able to access those talents.
- Long term sustainable funding from federal and provincial governments, umbrella agencies, and Foundations for Immigrant Service Agencies to offer employment services such as internships and language training.
- Expansion of the services offered by Immigrant Service Agencies to rural and remote communities.
- Offering intern opportunities for recent immigrants.
- Providing industry career information, recruitment material, and resources to educate service agency providers and recent immigrants on employment and career opportunities within the industry.

Develop strategies to attract and retain Canadian Aboriginal peoples in the workforce

In many provinces, natural gas utilities have developed partnerships in communities to attract and retain Canadian aboriginal peoples as future participants in the industry's workforce.

Develop strategies and processes to ensure effective transfer of knowledge and experience

Natural gas utilities need to develop strategies that allow for some redundancy and overlap between new employees and upcoming retirees. As well, new compressed training programs and innovative IT solutions will be required to better capture and transfer knowledge and experience. To facilitate this transfer of knowledge and experience, natural gas utilities will need to make new investments.

Natural Gas Utility Efforts Going Forward and the Cost Implications

Natural gas utilities continue to share specific best practices associated with workforce planning, succession planning, retention, recruitment and training. Costs will increase as natural gas distribution companies work to address the challenges associated with an aging workforce. The most significant cost increases will result from hiring replacement workers, increasing training programs, and the increasing cost of retention programs. It is estimated that a 1% increase in operating costs could reasonably be expected by utilities immediately and that costs could escalate up to 5% over the next few years. The natural gas utility industry will continue to raise the level of understanding among all stakeholders on the cost implications of an aging work force.

Summary

- The age of Canada's workforce population is increasing – and more so for the natural gas utility workforce.

- Human Resources Canada estimates that by 2011, 41% of the working age population will be between the age of 45 and 64 up from 29% in 1991. The percent of the workforce 45 years of age or older for natural gas utility companies is 52.9%.

- There are several reasons for this change in workforce demographics including:
    - There are limited numbers of qualified young workers currently employed across all industries.
    - Canada's birthrate has declined resulting in an overall shortage of available younger replacement workers in the future.
    - Canadians are retiring at a younger age than in the past and this is particularly true for natural gas utility companies.
    - Canada's jobless rate is the lowest it has been in thirty years resulting in competition for labour across the country.

- Natural gas utilities support a number of initiatives to attract, integrate, and retain new employees to ensure a continued highly skilled workforce. These include:
    - Developing strategies to attract and retain young workers, recent immigrants, and Canadian Aboriginal peoples as a key source of skilled labour.
    - Developing strategies and processes to ensure effective transfer of knowledge and experience.
    - Raising the level of understanding among all stakeholders on the cost implications of an aging work force.

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FORECAST ASSUMPTIONS

Line No.			2009 Projected	2010 Forecast	2011 Forecast
1	Customers:	Additions	6,120	5,600	5,850
2					
3		End of Year	837,965	843,565	849,415
4					
5		Average	833,798	839,949	845,633
6					
7		Percentage of Customer Growth - Average	0.98%	0.74%	0.68%
8					
9					
10	B.C. Inflation (CPI):	Conference Board of Canada		2.27%	2.05%
11		B.C. Ministry of Finance		2.20%	2.10%
12		RBC Financial Group		1.50%	1.80%
13		Toronto-Dominion Bank		1.60%	2.00%
14			(Approved)		
15		Average CPI	2.10%	1.90%	2.00%
16					
17		Labour Inflation	3.00%	3.00%	3.00%
18		Vehicle Inflation	2.71%	2.40%	2.50%
19					
20					
21			(Approved)		
22	Cost of Capital:	Short Term Debt Interest Rates	4.25%	2.25%	4.50%
23		Long Term Debt Interest Rates	6.96%	5.24%	6.13%
24		Return on Equity	8.47%	8.47%	8.47%
25					
26					
27	Income Tax Rate:	Federal	19.00%	18.00%	16.50%
28		Provincial	11.00%	10.50%	10.00%
29		Total	30.00%	28.50%	26.50%
30					
31	Foreign Exchange Rate:				
32		USD/CAD Exchange Rate	0.8393	0.8610	0.8871
33		CAD/USD Exchange Rate	1.1915	1.1615	1.1273
34					

1

[1] Dates of CPI forecasts as follows:

Source	Forecast Publish Date
Conference Board of Canada	April 2009
B.C. Ministry of Finance	September 2008
RBC Financial Group	October 2008
Toronto-Dominion Bank	March 2009

CODES AND REGULATIONS DETAILS

This section provides more details in support of the funding increases required to meet codes and regulation as identified in Application, Part III, Section C, Tab 6: Operations and Maintenance.

To ensure ongoing compliance to existing codes and anticipated new or changed codes, additional operating and maintenance funding is required. There are 4 main drivers to the increases:

- Inflationary costs e.g. increased external labour costs, materials costs, etc;
- Growth e.g. more services to inspect/maintain, more ROW to clear, more external activity to control/monitor;
- Asset age which increases risk profile e.g. more frequent inspections, more unplanned maintenance (repair), more replacements; and
- New or changed code requirements.

The reasons for incremental increases, outside of inflationary needs, from the 2009 projection for each of the codes are described below. A summary of associated dollars by code and department is shown below.

Table F-8-1: 2010 Code and Regulation incremental funding requirements ($ thousands)

Code	Distribution	GS&T	MKBD	B&ITS	HROG	Grand Total
BC Safety Authority				$410		$410
CSA Z246	$50	$100			$10	$160
CSA Z662 - Annex M & N	$1,412	$136	$1,000	$831	$322	$3,701
CSA Z662 - Annex A		$250		$25	$430	$705
CSA Z1000				$11		$11
Environmental Management Act					$90	$90
Power Engineers and Pressure Vessel Safety Act	$220					$220
Grand Total	$1,682	$486	$1,000	$1,277	$852	$5,297

Table F-8-2: 2011 Code and Regulation incremental funding requirements ($ thousands)

Code	Distribution	GS&T	B&ITS	HROG	Grand Total
BC Safety Authority			$127		$127
CSA Z246	($50)				($50)
CSA Z662 - Annex M & N	$883	$1,151	($42)		$1,992
CSA Z662- Annex A			$100	($90)	$10
Environmental Management Act				($20)	($20)
Grand Total	$833	$1,151	$185	($110)	$2,059

The following table identified the detailed items by code and department:

Table F-8-3: 2010 Code and Regulation detailed incremental funding requirements ($ thousands)

Description	Distribution	GS&T	MKBD	B&ITS	HROG	Grand Total
BC Safety Authority - Gas Safety regulations- 2 day turnaround				410		410
CSA Z246 - Security- Security Assessment	50	100				150
CSA Z246 - Security- Security Management Program					10	10
CSA Z662 - Annex M & N – Competency & Training- Competency				109		109
CSA Z662 - Annex M & N – Competency & Training- Competency Administration					105	105
CSA Z662 - Annex M & N – Competency & Training- Web based training					100	100
CSA Z662 - Annex M & N - Records Management- Gas Installations - Data integrity	150					150
CSA Z662 - Annex M & N - Records Management- Repatriate Corrosion Data				56		56
CSA Z662 - Annex M & N - Records Management- Records Clerk				60		60
CSA Z662 - Annex M & N - Records Management- Compliance Record Manger				150		150
CSA Z662 - Annex M & N - TG IMP- IMP staffing	215					215
CSA Z662 - Annex M & N - TG IMP - Programs- Cathodic Protection/Assessment	80					80
CSA Z662 - Annex M & N - TG IMP - Programs- Class Location	120					120
CSA Z662 - Annex M & N - TG IMP - Programs- Corrective Maintenance	402					402
CSA Z662 - Annex M & N - TG IMP - Programs- CP surveys, data transfer				212		212
CSA Z662 - Annex M & N - TG IMP - Programs- Inspecting Bridge and Aerial Crossings	30					30
CSA Z662 - Annex M & N - TG IMP - Programs- IT System Support related to codes				105		105
CSA Z662 - Annex M & N - TG IMP - Programs- Nox				15		15
CSA Z662 - Annex M & N - TG IMP - Programs- Odorant				31		31
CSA Z662 - Annex M & N - TG IMP - Programs- Preventative Maintenance	(117)	100				(17)
CSA Z662 - Annex M & N - TG IMP - Programs- Public Safety Awareness			1,000		117	1,117
CSA Z662 - Annex M & N - TG IMP - Programs- Pipeline Identification	100					100
CSA Z662 - Annex M & N - TG IMP - Programs- ROW Lands Management				93		93
CSA Z662 - Annex M & N - TG IMP - Programs- Seismic Risk Assessments	150					150
CSA Z662 - Annex M & N - TG IMP - Programs- Transmission Integrity Programs		36				36
CSA Z662 - Annex M & N - TG IMP - Programs- Valve Maintenance	200					200
CSA Z662 - Annex M & N - TG IMP - Programs- Vegetation Management	175					175
CSA Z662 - Annex M & N - TG IMP - Programs- TGVI offset	(93)					(93)
CSA Z662 - Annex A - - Business Continuity & pandemic program					315	315
CSA Z662 - Annex A - - Emergency Preparedness					115	115
CSA Z662 - Annex A - - Gap Closing		250				250
CSA Z662 - Annex A - - Radio support				25		25
CSA Z1000 - OH&S- Safety Recognition				11		11
Environmental Management Act - - Environmental Programs					90	90
Power Engineers and Pressure Vessel Safety Act - - Heat & pressure vessel inspection & mtce	220					220
Grand Total	1,682	486	1,000	1,277	852	5,297

Table F-8-4: 2011 Code and Regulation detailed incremental funding requirements ($ thousands)

Description	Distribution	GS&T	B&ITS	HROG	Grand Total
BC Safety Authority - Gas Safety regulations - 2 day turnaround			$127		$127
CSA Z246 - Security - Security Assessment	($50)				($50)
CSA Z662 - Annex M & N – Competency & Training - Competency			$20		$20
CSA Z662 - Annex M & N - Records Management - Data transfer			$17		$17
CSA Z662 - Annex M & N - TG IMP – IMP staffing	$185				$185
CSA Z662 - Annex M & N - TG IMP - Programs - Class Location	($60)				($60)
CSA Z662 - Annex M & N - TG IMP - Programs – Corrective Maintenance	$139				$139
CSA Z662 - Annex M & N - TG IMP - Programs - Cost of Odorant			$10		$10
CSA Z662 - Annex M & N - TG IMP - Programs - CP surveys, data transfer			($106)		($106)
CSA Z662 - Annex M & N - TG IMP - Programs - IT System Support related to codes			$2		$2
CSA Z662 - Annex M & N - TG IMP - Programs – Preventative Maintenance	$402				$402
CSA Z662 - Annex M & N - TG IMP - Programs - ROW Lands Management			$15		$15
CSA Z662 - Annex M & N - TG IMP - Programs - Single Point of Failure Analysis	$200				$200
CSA Z662 - Annex M & N - TG IMP - Programs - Vegetation Management	$50				$50
CSA Z662 - Annex M & N - TPIP - rebase		$1,151			$1,151
CSA Z662- Annex A - - Business Continuity & pandemic program				($90)	($90)
CSA Z662- Annex A - - Radio support			$100		$100
Environmental Management Act - - Environmental Programs				($20)	($20)
CSA Z662 - Annex M & N - TG IMP - Programs – TGVI offset	($33)				($33)
Grand Total	$833	$1,151	$185	($110)	2,059

a) BC Safety Authority: Safety Standards Act and Gas Safety regulations

The BCSA change to the Procedures for Excavations section of the Gas Safety Regulation significantly impacts the operations of Terasen Gas. Prior to April 1, 2008, a gas company was given 3 days to provide gas system information requested by a third party. In response, the Location Records Department at Terasen Gas was adequately staffed to meet this requirement on an ongoing basis. On April 1, 2008, the regulation was changed to state that "*on receiving a request under subsection (2) a gas company must provide the information requested within 2 business days*[1]". Subsequently, Terasen Gas formulated its response strategy to the changed regulation while every effort was made to meet the changed requirement. In late 2008, it was determined that staffing levels in the Location Records Department needed to be increased in order to meet the 2 day turnaround requirement. Consequently, additional people were hired and trained to work in the department and information requests have since been turned around within 2 business days.

The incremental costs are being offset in 2009 by reducing costs temporarily elsewhere, but these reductions cannot be continued into the future. To continue to process information requests and to meet the 2 day turnaround requirement of the Gas Safety Regulation on a continuing basis, the increased staffing levels need to be maintained in 2010 with an additional 2.0 headcount increase in 2011 to meet the 2 day turnaround. The incremental cost of this headcount addition is $410 thousand

[1] BCSA Gas Safety Regulation

in 2010 and an additional $127 thousand in 2011. In addition, the IT O&M budget needs to be increased by $10 thousand in 2010 to be able to acquire the necessary software licenses for the additional staff.

Terasen Gas needs this funding in order to comply with the requirements of the Gas Safety Regulation and support the BC Safety Authority to achieve greater safety for the excavation community. Compliance is a key pillar of Terasen Gas' focus on safety and integrity and needs to be funded appropriately. Therefore the Operations Engineering funding requirement within B&ITS is increased by $410 thousand in 2010 and an additional $127 thousand in 2011.

b) CSA Z246

The Company's gas system assets are part of the critical energy infrastructure in British Columbia. Terasen Gas's Corporate Security program works to minimize the risk of theft, vandalism, sabotage and terrorism to assets that are necessary to provide safe, reliable delivery of gas. The scope of the Security program includes buildings, gas system infrastructure, tools and equipment, and information technology systems related to gas delivery.

Terasen's corporate security program will continue to be strengthened, particularly by continuing to include simulated security incidents in emergency exercises, ensuring alignment with the emerging Canadian Standards Association requirements, and coordinating the planning of 2010 Olympic preparation.

Emergency planning agencies consider critical infrastructure such as natural gas facilities prime targets for terrorists. Societal expectations are that Terasen Gas provides safe reliable service with minimal risk due to vandalism and/or terrorism. Implementation of CSA Z246.1, Security Management for Petroleum and Natural Gas Industry Systems will formalize those expectations. CSA Z246 is expected to be released October 2009, and the OGC and NEB have indicted that it will adopt it into regulations. Enactment of CSA Z246.1 will bring new requirements designed to improve natural gas facilities protection from vandal and terrorists activities.

Risk assessments on critical infrastructure will be required by Distribution (one-time $50 thousand in 2010) and Transmission ($100 thousand increase in 2010 and continuing into 2011). In addition, an enhanced security program will need to developed within the EH&S group of HROG for a sum of $10 thousand in 2010, continuing into 2011.

c) CSA Z662 - Annexes N & M: Terasen's Integrity Management Plan (IMP)

(1) INTRODUCTION

CSA Z662 defines requirements throughout the lifecycle of transmission and distribution gas assets including design, installation, and operations. Recent additions of Annex M & N to CSA Z662 bring heightened focus to integrity management. Integrity management and asset management are two disciplines that are closely linked together. Terasen Gas believes it is critical to continue focus on these disciplines to ensure safe, reliable, and cost effective operations.

The goal of integrity management of gas distribution systems and pipelines is to provide safe, environmentally responsible and reliable service with focus on mitigating and managing the potential for external interference, failure and damage incidents. These incidents may result in an immediate unplanned release of gas or cause damage to a pipe, component or coating which increases the likelihood of an unplanned release in the future.

The goal of asset management is to optimize the asset's life-cycle value so that it provides safe, environmentally responsible and reliable service for optimum cost, balancing the repair/replace equation against capacity and integrity needs.

Neither discipline is new for the natural gas Industry nor for Terasen Gas; however, both disciplines have evolved and improved over the years, with technology changes and best practices development spurring on the change. At Terasen Gas, this evolution can be demonstrated by the development of proactive programs for managing asset integrity through to the implementation of a formal Integrity Management Policy and Plan, plus the creation of Asset Management departments within Distribution and Transmission. This approach has lead to better overall control of work and priorities, more consistency in planning and execution, and less duplication of organizational structure.

Terasen Gas prides itself on delivering safe, reliable, environmentally responsible and cost effective service to its customers. It performs integrity and asset management to effectively manage the risks associated with its pipelines and facilities, while also meeting regulatory requirements.

Prior to the PBR period, Terasen Gas had already established many activities to manage integrity and asset health including, but not limited to:

- Retrofitting pipelines to allow for in-line inspection;
- Developing a robust set of standards and a standards management process;
- Educational programs to reduce third-party damage and to promote public safety awareness;

- Undertaking seismic studies and performing extensive soil remediation work to strengthen earthquake resistance of pipelines and key delivery and storage sites; and
- Implementing a geographic information system to automate the storage of many aspects of asset information.
- Implementing SAP plant maintenance functionality to enable improved planning and tracking of maintenance work.

Over the PBR period, Terasen Gas continued to improve its integrity and asset management activities. Some examples include:

- Performing in-line inspections of retrofitted pipelines, and continuing analysis to optimize re-inspection intervals;
- Developing and implementing vegetation management plans that recognize regional growth differences and also comply to new and evolving environmental requirements;
- Developing a formal Integrity Management Policy and Plan (IMP) (described in more detail below);
- Performing an internal audit of its IMP;
- Developing and implementing an Environmental Management System; and
- Developing an OH&S management framework.

There are two areas which require additional work, and thus incremental funding. These are Competency and Training, and Records Management. In addition individual IMP programs are facing funding pressures and each will be discussed below.

(2) COMPETENCY & TRAINING

With the adoption of CSA Z662 Annex M and N formality and rigor are required around competency and training requirements for employees and other workers who impact asset integrity through their work.

In order to comply with these requirements we have developed a competency and training model, and have identified the required competencies for work performed on the distribution and transmission systems. We have incorporated competency definitions created by a taskforce within the CGA to ensure completeness and national consistency.

We are now evaluating employees that perform work related to asset integrity. Training and supervised experience is provided where deficiencies in skill or knowledge are identified. This information will be maintained in our Learning Management System.

In some cases we have chosen to rely on recognized external organizations to establish, validate and maintain the competency and training of affected staff as appropriate. For technical staff within Corrosion, we have chosen to adopt the training and certification program from NACE International ("National Association of Corrosion Engineers"). The NACE certification program was chosen because "*NACE International is the leader in the corrosion engineering and science community, and is recognized around the world as the premier authority for corrosion control solutions. The goal of their programs is to develop corrosion professionals that can support … protecting people, assets, and the environment from the effects of corrosion.*[2]" We aligned internal job descriptions with the NACE certification program in late 2008 in order to formalize our requirements for the various positions in the group. Effective January 2009, this alignment creates a pressure of $67 thousand to accommodate a resulting job reclassification and training requirements for the group. The incremental costs associated with these initiatives are unfunded and are being treated as a budget pressure. Budget opportunities will need to be realized within Operations Engineering or other parts of Terasen Gas in order to cover this pressure. The long term impact of this alignment, however, is a need to increase the Corrosion group O&M budget by $67 thousand in 2010 and by an additional $20 thousand in 2011 to fund job reclassifications and on-going training requirements.

For Professional Engineering staff, we will continue to rely on the Association of Professional Engineers and Geoscientists of BC ("APEGBC") as recognized external organizations to establish, validate and maintain the competency and training of affected staff. Similarly, we will continue to rely on the Applied Science Technologists and Technicians of BC ("ASTTBC") for the competency and training elements for our Technologists. Both professional organizations have established educational and "right to practice" requirements for their members. Both organizations also recommend that their members pursue continuing professional development throughout their career to ensure their continued competence. They offer applicable courses for members, promote conferences, and provide opportunities for members to report any continued professional developments. The incremental cost of administering the competency and training model to our technical staff outside the Corrosion group is a one time increase of $42 thousand in 2010. Our technical staff have pursued continuing professional development in the past under a different regulatory requirement. Incremental funding is required to meet the increased rigor of the Annex N requirement.

The combined Corrosion and Operations Engineering O&M funding requirement within B&ITS is increased by a total of $109 thousand in 2010 and an additional $20 thousand in 2011 to allow us to meet the new competency and training requirements of Annex N. These incremental funds will allow us

[2] NACE website

to adopt and implement a competency and training model that relies on recognized external organizations to establish, validate and maintain the competency and training of affected staff.

(3) RECORDS MANAGEMENT

To strengthen our records management processes, we are taking steps in other departments across the Company to comply with the various components of Section N.6.1 and N.6.2. We have been working on a project to implement a formal and central records management system to manage compliance records on a go forward basis. As such, we are implementing a records management tool called FileNet and developed applicable records management processes to be used within this application. We are also implementing a sustainment model where all compliance records will be managed centrally.

There are three additional areas that require additional funding related to records management and they are presented below.

(a) Gas Installations

Terasen records of gas installations are estimated to be 98% accurate. There are areas that have been identified where there are gaps in records including inaccurate pipe location and missing pipe and coating condition. Processes are in place to update pipe locations when errors are found. When a portion of a buried or submerged pipeline system becomes exposed, codes require a visual inspection for corrosion and condition of coating. Pipe and Coating reports provide critical information on the condition of pipe and coating; this data is used as an input on repair vs. replace decisions. Before the introduction of Automated Mapping/Facilities Management (AM/FM), this information was stored in hard copy books. The deteriorating condition of these books will result in the eventual loss of this data. The existing process to completely update all records is very lengthy and is introduces an unacceptable area of high risk. To transfer this information from the hard copy books to the AM/FM system, Distribution requires an incremental amount of $150 thousand starting in 2010.

Accurate location information is critical as part of the Terasen Gas damage prevention process and is required by the Gas Safety Regulations Clause 39(5). By collecting and maintaining accurate location data Terasen Gas will be able to provide excavation contractors and personnel with the information they require to avoid damaging underground pipelines. Up to date pipe and coating data will result in improved repair/replace assessments.

(b) Corrosion – repatriate critical cathodic protection records from contracted service provider

Currently and in the past, we have contracted the services of DNV (formerly known as CC Technologies) to manage the cathodic protection systems located in the BC Interior. As a result, critical records related to the design and performance of the BC Interior cathodic protection systems is retained with CC

Technologies. Terasen Gas has no records on its AM/FM system related to the cathodic protection systems found in the BC Interior. Consequently, we require a one time amount of $56 thousand in 2010 to transfer the critical cathodic protection records from DNV to the Terasen Gas AMFM system. The reason for this data transfer is to ensure that we have records of all of our cathodic protection systems in AMFM and are in compliance with Annex N.6.1(j).

(c) Corporate centralized compliance records management

We have been working on a project to implement a formal and central records management system in Operations Engineering to manage compliance records on a go forward basis as mentioned in Part III, Section B, Tab 2, The Future. We are also implementing a sustainment model where all compliance records in Operations Engineering will be managed centrally. One incremental full time clerk will be responsible for filing all compliance related records and managing the applicable records related processes. As a result, the Operations Engineering O&M budget is increased by $60 thousand starting in 2010 in order to allow for the hiring of a full time records clerk so that records can be filed and maintained in a manner that will allow us to demonstrate compliance with Section N.6 of Annex N.

Clause 10.2.1 states that "Operating companies shall develop, implement, and maintain a documented safety and loss management system for the pipeline system that provides for the protection of people, the environment, and property". Clause 10.2.2 then proceeds to provide the details of the elements that should be included in a loss management system and also refers to Annex A for an extensive guideline for the same. We have many disparate programs and management systems across the organization that exist to meet specific requirements of various regulations. For example, we have an Environment Management System, a Natural Hazards Management Program, a Vegetation Management Program, and others. Clause 10.2.2, Annex A, N & M are similar in their requirement for companies to have a holistic and integrated approach with their various systems and programs. We need to ensure that our systems contain the appropriate elements, are aligned and integrated, and that they are producing the appropriate outcomes to allow us to demonstrate compliance with the various sections of CSA Z662 with respect to management systems. As a result, the 2010 Operations Engineering funding requirement is increased by $150 thousand to be able to perform this activity.

(4) STAFFING REQUIREMENTS FOR IMP

(i) Distribution

Current staffing levels in Distribution Asset Management are insufficient to implement the requirements of the Integrity Management Plan. The full adoption of CSA Z662, Annex N will increase the workload for this group as follows:

- Additional Maintenance Analyst in Asset Management.
    - Administer programs that monitor for conditions that may lead to failures, to eliminate or mitigate such conditions.
- Two Field Quality Auditors in Asset Management.
    - Will enable the field quality audits that are required by the Terasen Gas Integrity Management Plan and CSA Z662
- Additional Professional Engineer in Asset Management
    - Analysis and decision making specific to capital budget investments. This will include conducting studies or analyzing studies by others to understand issues, ensure budgets are invested on the higher priority items and applicable standards are maintained.
- Two Additional Operations Support Representatives in Asset Management
    - Support the increased requirement for records to demonstrate compliance by becoming an expert on FileNet (the new records administration technology being introduced in 2009).

Although Integrity Management is not entirely new to Terasen Gas, the full adoption will result in a more comprehensive and formalized demonstration of compliance and enhancements to the program in 2010 and 2011; to ensure that all applicable codes and regulations are met and the distribution system continues to operate safely and reliably. To accomplish this, Distribution funding requirement is increased $215 thousand in 2010 and $185 thousand in 2011.

(5) SPECIFIC INTEGRITY PROGRAMS

(a) Cathodic Protection/ Assessment

The following factors have influenced the application and monitoring of cathodic protection (CP) to Terasen Gas' buried steel piping systems over the past number of years:

- average age of steel pipeline assets is increasing;
- third-party activity in the vicinity of pipelines has increased;
- integrity and corrosion management technologies have evolved;
- industry standard practices for the monitoring and management of corrosion have become increasingly rigorous; and
- regulatory expectations have increased.

While cathodic protection has been applied for decades, Terasen Gas and other pipeline operators have continued to take steps to improve comparisons of measured CP system performance against industry established criteria. These changes will improve confidence levels that CP systems are effectively mitigating corrosion and preventing premature degradation of installed pipelines, however will also result in increased workloads.

Another incremental workload increase has resulted from an increase in electrical shorts, which drain CP current away from the pipeline and potentially result in corrosion. Influencing factors for these shorts include reduced coating performance (electrical isolation properties) as pipelines age and increased construction activities in the vicinity of pipelines. Terasen expects that this activity will continue or possibly increase over time.

Based on the above increases in activity and cost levels, the Corrosion O&M funding requirement within B&ITS requires a permanent increase of $206 thousand in 2010. In addition, Distribution requires a permanent increase in 2010 of $80 thousand.

We have initiated the implementation of a data management system (DMS) for the Corrosion group that will house the methods used and the results obtained from our cathodic protection activities and, at the same time, it will provide the required index of corrosion related records. The project is scheduled for completion in mid 2009 and will have ongoing IT O&M cost of $27 thousand per year.

Also, increased funding in 2010 is required for the cost of electricity used by the rectifiers that impress the cathodic protection onto our steel gas systems. We must have cathodic protection on our steel gas assets on a continuous basis and, consequently, we must incur the associated electrical costs. It is estimated that the total cost of electricity consumed by our rectifiers will increase by $6 thousand in 2010, bringing the incremental funding requirement for B&ITS in this program to $239 thousand starting in 2010 ($212 thousand for Operations Engineering and $27 thousand for IT). Without the incremental funding it will be difficult to continually improve cathodic protection programs to keep pace with current standards, practices, and regulatory requirements.

(b) Class Location (Intermediate Pressure Pipeline) Survey

Pipelines are assessed a class location in order to identify population density. This class location provides design safety factors and is used to establish operations and maintenance programs in keeping with the consequences of asset failure in more densely populated areas. Many class locations change as a result of increases in population density or location development which has resulted in the need to update and refresh class location data. Transmission pressure pipelines are regularly surveyed to monitor for class location changes.

BC has had the highest housing starts in the country over the PBR period, resulting in increased population density around transmission pipe. As communities encroach on Transmission statutory rights-of-ways, Transmission's operating practices must change. Patrol frequencies in some areas must increase from once a year to once a week/month. In other cases engineering studies must be undertaken to see if pipeline upgrades and other bypasses are necessary, with the appropriate action implemented. Increases in costs are associated with the increased survey periods and/or other mitigation actions.

Distribution requires $120 thousand in 2010, with $60 thousand continuing into 2011, in order to perform one-time comprehensive and ongoing class location surveys of its intermediate pressure pipeline. Maintaining up to date class locations will ensure that pipeline systems are operated in accordance with the intent of CSA Z662 and within acceptable levels of risk to public, plant and employee safety.

(c) Corrective maintenance

Regular preventive maintenance is completed on gas system assets to ensure safe and reliable delivery of gas to customers. As many of the failure modes associated with the types of equipment and the operating conditions are random, they cannot always be prevented by preventive maintenance. As a result, assets are designed to ensure they continue to operate even when a piece of equipment fails. Corrective maintenance is initiated when equipment fails and is identified as part of the regular preventive maintenance program.

Technology is limited in its ability to predict failures on piping systems (i.e. there are no internal inspection tools or 'smart pigs' available for distribution or intermediate pressure pipelines). Traditional methods have limited success in predicting failures (i.e. cathodic protection monitoring). Surveys such as 'leak surveys' are designed to identify piping system failures at an early stage where the risk to the public is minimized. Identifying and correcting failures is normal aspect of maintaining gas system assets.

Based on past experience and system age, Distribution requires an incremental funding of $402 thousand starting in 2010 to perform corrective maintenance activities, with an additional increase of $139 thousand in 2011.

As the gas distribution infrastructure grows and ages, failures are monitored closely to determine whether the optimal level of preventive maintenance is being completed (i.e. increases in corrective maintenance are analyzed to determine the root cause and whether an appropriate preventive measure is available). Adequate corrective maintenance resources, coupled with adequate preventive maintenance resources, are a critical aspect of asset management and the programs designed to maximize the service life of the assets.

(d) Inspecting Bridge and Aerial Crossings

Bridge and Aerial Pipeline Crossings are inspected periodically to ensure continued safe, reliable delivery of natural gas. Generally there is adequate funding to complete the inspections; however, with aging infrastructure, requirements for subsequent corrective work are under-funded.

During the period 2004-2009, findings from previous inspections were examined and prioritized, much of the work was deferred as the associated risk was evaluated and deemed to be acceptable at that time. This work can no longer be deferred without increasing the risk of asset failure or resulting expensive renewal of the asset. As a result, Distribution requires additional funding starting in 2010 of $30 thousand.

Completing the corrective work will ensure the continued safe, reliable and cost effective delivery of natural to the customers served by those pipelines.

(e) Odourization

As a safety measure, we are required under regulation to odorize the natural gas we distribute to customers. The total annual cost of odorant is expected to increase by $31 thousand in 2010 and by another $10 thousand in 2011 because of the projected increases in the price of the commodity.

(f) Pipeline Identification

CSA Z662, requires signs to be installed to identify the presence of pipelines in order to reduce the possibilities of damage and interference. A comprehensive review of the Terasen Gas Intermediate Pressure (IP) systems will ensure adequate and appropriate identification is in place in accordance with CSA Z662 and Terasen Gas standards. Many of the signs currently in place are outdated or illegible. In order to accomplish this, Distribution requires additional funding commencing in 2010 of $100 thousand.

Terasen must continue to meet all applicable regulatory requirements and will take such actions that are appropriate to prevent third party damages to Company assets. This will help ensure continued safety of the public, the plant and company employees as well as the continued reliable service to Terasen Gas' customers.

(g) Preventive Maintenance

Terasen Gas administers a preventive maintenance program designed to extend the life of assets while ensuring optimal investment of maintenance resources.

Regular preventive maintenance is performed on Terasen Gas assets based on the integrity management program. There are a variety of Code requirements that define the elements of a preventive maintenance program. In some instances Code requirements are prescriptive in what must be included in a preventive maintenance program; in other instances the onus is put on the operator to decide what is in an appropriate program.

Commencing in 2001, Distribution began transitioning to a risk based maintenance program leading to the implementation of SAP Plant Maintenance functionality in 2003. SAP enables gathering of data on asset performance, failure modes and failure frequencies. Anecdotal data, validated by documented observations have enabled adjustments to maintenance frequencies and programs that have resulted in significant savings with no loss of asset reliability while maintaining Code compliance. The numbers of activities for 2010 and 2011 (I.e. visits to an asset) are based on asset growth, observations and maintenance results which are dynamic, based on operating conditions in the system and result in the need for a reduction of funding in 2010 of ($-117 thousand) and an increase in 2011 of $402 thousand.

Transmission will be looking to improve its asset management capabilities by leveraging the existing ERP system in the organization, most notably SAP-PM. Transmission plans to add one additional headcount for analyst support for the planned maintenance system upgrade for an incremental cost of $100 thousand starting in 2010.

Preventative maintenance is the first line of attack to ensure safe and reliable service and Terasen Gas requests that the additional funding for these activities be granted.

(h) Public Safety Awareness

Terasen Gas has a responsibility to educate the public about the risks associated with its natural gas and propane products. One of the Company's main objectives regarding public safety awareness is to support safe, secure and healthy communities by increasing public awareness of gas safety risks and the steps that can be taken to minimize the potential for accidents.

A variety of methods including media ads, bill inserts and the Terasen Gas web-site have been used as channels for this program during the PBR period. For example: Terasen Gas has recently become a financial sponsor of the Cooperative Safety Program, which provides education to communities across the southern interior of British Columbia. The multi-media campaign focuses on increasing utility safety awareness to both the general public and industry professional audiences.

In addition, Terasen Gas is a member of BC One Call and part of the Common Ground Alliance, an industry group that includes utilities as well as excavators. We also work with fire departments including the joint development of training programs for firefighters. External parties must comply with our permit process if they plan work around our pipeline.

There are two areas requiring incremental funding, public safety awareness staffing and public safety awareness messaging, and they are presented below.

(i) Staffing

Terasen Gas has a responsibility to educate the public about the risks associated with its natural gas and propane products. To accomplish this, Terasen Gas, is expected to coordinate programs and activities to inform customers and the public about natural gas and propane safety by:

- Collaborating and ensuring coordination amongst the business units that develop and deliver public safety awareness materials and programs;
- Developing and supporting Terasen Gas programs and activities to educate customers and the public about natural gas and propane safety;
- Participating in appropriate joint public safety programs with other industry stakeholders;
- Advising on public safety communication strategies for Terasen Gas and recommending actions, standards, research, and budgets;
- Coordinating public safety surveys and interpreting the data;
- Devising and leading required actions based on survey data collected.

At present, there is no position at Terasen Gas devoted to public safety awareness. Promoting public safety awareness is the combined effort of personnel from many of the Company's business units, including one management and exempt position in EH&S that is primarily responsible for emergency planning.

Channeling all public safety initiatives through one department would allow for the capture of synergies and efficiencies, since public safety initiatives occur in many business units, and vary in the different geographic regions. A key requirement of Annex A within the Integrity Management Plan is for Terasen

Gas to have the ability to track and document theses initiatives. Other expectations of the public safety group in relation to the Integrity Management Plan are to:

- Provide a primary point of contact within the Company for public safety components of the Integrity Management Plan;
- Ensure that asset owners are informed of any significant risks (e.g. program performance, relevant asset metrics) and provide recommendations to resolve;
- Establish and monitor performance level metrics, ensuring corrective action as required;
- Ensure that program review and evaluation are conducted and documented appropriately;
- Lead continuous improvement initiatives to Public Awareness Processes as identified by the IMP Management Team
- Additionally, there is a need to implement a governance component to ensure that public safety initiatives align and complement the corporate public safety goals.

A focused program is required to improve the public's knowledge and behaviors regarding gas safety. Between 2001 and 2006, combined public recognition and action awareness levels remained unchanged at 10%, as per the 2006 Terasen Gas Safety Research Survey. The Company's most recent corporate Safety Awareness Study of customers, conducted in 2008 reflects results similar to the 2006 public survey in that less than ten percent of the public are aware of what to do when they smell gas. This demonstrates that knowledge of what to do in the event of an emergency, or to avoid one, has not improved over 10 years. A combination of an increased communications budget and a focused, dedicated position in public safety awareness is necessary to improve the public's awareness levels.

There is an increased provincial focus on collaborative, inter-agency safety messaging. Partnerships, with external stakeholders to create and disperse collective gas safety messaging, need to be strengthened. Delivery of gas energy safety requires a cooperative approach to ensure consistent, wide audience messaging and Terasen Gas needs to take a lead.

The Provincial Emergency Program (PEP) is leading the establishment of an on-line preparedness education and training tool around provincial hazards such as earthquakes, floods and forest fires. The project will be composed of modular, expandable curriculums aimed at a broad audience, including multi-lingual public, First Nations and businesses. Participation by multiple agencies is required to develop and launch the tool. Terasen has been asked to participate, but has not been able to provide resources (BC Hydro is intimately involved in the committee and is an endorsing sponsor).

Terasen Gas has recently become a financial sponsor of the Cooperative Safety Program, which provides education to communities across the southern interior of British Columbia. The multi-media campaign focuses on increasing utility safety awareness to both the general public and industry professional audiences. Greater participation by Terasen in the managing committee would improve the gas safety messaging and allow for improved collaboration around issues like Call Before You Dig.

Devoting a resource to public safety awareness would allow for the expansion of the Terasen Gas school program which is a key tool used in the education of the public regarding gas safety. A dedicated lead could implement and track the success of long-term goals in the Terasen Gas school program. More regular surveys to track gas safety knowledge and awareness could take place amongst the public and Terasen's customers. In addition, this position could also concentrate efforts to establish and maintain partnerships and shared programs with other organizations such as the fire services, other utilities, and community organizations.

Customers, the public and policymakers expect that Terasen Gas has dedicated, safety-focused resources like BC Hydro which has a three-person (Manager plus two advisors) Public Safety Department. Within the CGA, Saskatchewan Energy has a Public Awareness Coordinator and GazMetro has a full-time Supervisor whose job was created in order to prevent damage and educate the public.

To summarize, the creation of a position in public safety awareness would allow for an expanded public safety governance program and would ensure that public safety awareness programs are coordinated in an effective manner and expanded to increase overall public safety. To this end the HR & Governance funding requirement has been increased by $117 thousand starting in 2010.

(ii) Communications

Terasen Gas believes that is prudent to cast an annual safety communications budget that is more reflective of the dollars required each year to provide our customers with information to help keep them safe. We also believe that as a responsible operator we should be seeking to raise awareness levels regarding gas odour and action to a level greater than 10 per cent.

Currently, Terasen Gas budgets $140 thousand per year on safety communications – approximately $0.15 per customer. Activities include: infrequent radio and newspaper campaigns; media releases and earned media; brochures; annual letters; damage prevention program; school program and the TerasenJr. web page. As well, safety messaging is added to all communications materials, where appropriate, to reach as many audiences as possible.

This budget number of $140 thousand has not increased in over 10 years but over that time period our customer base has grown and new communities have been added to our service areas. In fact, between 2006 and 2009 (year-to-date), Terasen spent approximately $435 thousand above budget on safety communications. This money was to primarily supplement four key safety messages: flood preparedness, meter safety, call before you dig, and fall safety tips in addition to gas odour awareness and action. Additional funds were also required to ensure Terasen was providing safety information to customers and members of the public who speak Punjabi and Cantonese rather than English.

It should be noted that other companies spend significantly more to provide their customers with safety information. For example, BC Hydro is currently known to spend at least $3.6 million on safety education. BC Hydro has an extensive radio campaign to educate British Columbians regarding the *Seven Steps to Electrical Safety*. In 2006, the Canadian Gas Association released a study which indicated how much its member companies spent per customer on safety. The study did not include the number of messages each budget needed to support or the overall awareness level achieved for a particular message. The study indicated that in 2006 ATCO spent $1.06 per customer and Enbridge spent $0.50.

Since the last PBR settlement Terasen Gas has undertaken a mass media campaign for Customer Choice and in the first year of the program was able to go from zero awareness to approximately 80 per cent, several months later. The program is now being sustained at a lower level of media (newspapers and online) but is an example of the power of mass media campaigns, especially those involving TV.

This Application presents an opportunity to address the base budget for safety communications, and to reflect the new Oil & Gas Commission regulations. There is tremendous value in empowering customers, through knowledge to help them stay safe and avoid harm or property damage.

Through our corporate image and customer satisfaction surveys, customers have indicated that the Company's safety information is of value. By increasing knowledge, Terasen Gas can help customers avoid potentially harmful situations, which could result in serious injury or damage to Company assets. We are focusing a targeted effort on gas odour awareness and action due to the current low level of awareness and that it can help protect customers in their homes and businesses, along a right of way or where third party damage may have occurred.

While CSA Z662 Annexes M&N are not prescriptive in what public safety awareness activities should be undertaken, the reference of increased public awareness in the regulations should be seen as significant because it suggests that there are two key aspects to public safety – the integrity of the system and an educated public that through knowledge can avoid harm.

We believe as a prudent operator we should explore an incremental increase to the frequency of our current media plan (radio and print), focused primarily around gas odour and awareness and an incremental $1.0 million has been added the MKDB funding requirement for this. Terasen Gas would continue our existing approach in support of the other safety messages.

(i) Rights Of Way (ROW) Land Management

An increase is required to fund our land management activities to account for increased cost of managing and administering land easements, ROW and continue land acquisitions activities.

Terasen Gas pipelines and mains traverse the landscape like a web and, each year, we need to enter into a number of easement or ROW agreements in order to cross private, public or crown land to be able to provide service to customers and negotiate renewals of expiring ROW licenses or permits. The necessary agreements usually result in annual fees or amortized lump sum fees that we have to pay for the easement or ROW rights. In addition to completing over 650 distribution easement agreements over the past two years, we entered into two transmission right of way agreements in 2007 and two in 2008.

Incremental funding of $93 thousand in 2010 and an additional $15 thousand in 2011 is required. Lack of funding will result with the consequences of potentially having important infrastructure in place without legal tenure and agreements that are less favorable for Terasen Gas than if we had been fully involved with the negotiation process.

(j) Seismic Risk Assessment

Terasen Gas continues to work to ensure Code requirements are met so that natural gas can continue to be delivered to our customers safely, reliably and cost effectively. In 1994 a seismic study was conducted of certain areas of the Terasen Gas system. Since that time new standards have been enacted specific to seismic design. Understanding of seismic vulnerabilities will enable planning and programs to mitigate the risks.

Due to the size and complexity of the natural gas distribution system, the assessment of seismic risk needs to be spread over a number of years. To accomplish these studies, Distribution requires incremental funding of $150 thousand starting in 2010. An ongoing program of seismic risk identification and mitigation will ensure continued safe, reliable service to our customers.

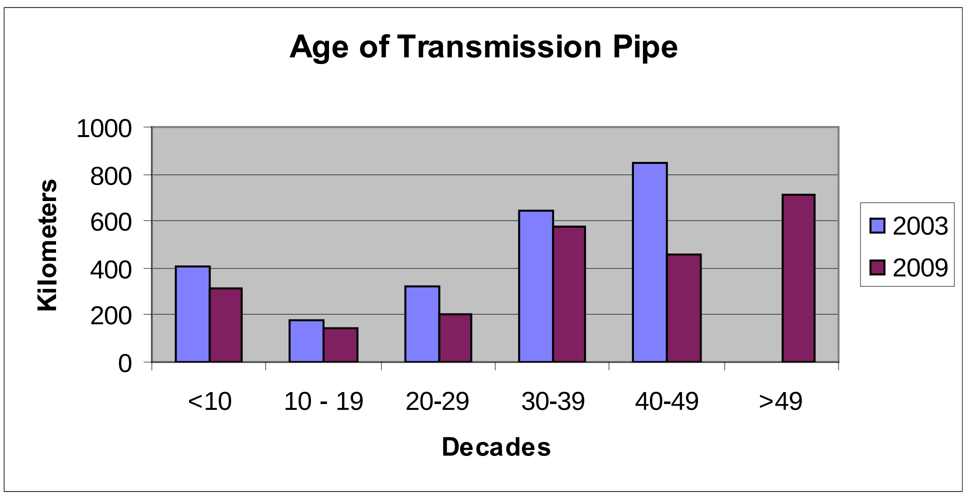
(k) Single Point of Failure Analysis

Terasen Gas is committed to providing natural gas to its customers safely, reliably and at the lowest cost. Third party damages, natural and man-made hazards impact distribution pipelines regularly. The natural gas distribution system is complex and includes a number of instances where loss of a single pipeline may result in customer outages. The Transmission system, while not as complex, holds a greater consequence to customer outages in situations where a single point of failure occurs.

A comprehensive study is required to identify the single points of failure, assess the probability of the failure occurring and identify the consequences of that failure. Distribution requires additional funding of $200 thousand in 2010 to perform analysis of the assets under its accountability. Comprehensive knowledge of the areas of vulnerability will enable Distribution to identify areas of high risk, setting the groundwork for plans and programs to reduce those risks to an acceptable level. Transmission is performing the same type of activity in 2009.

(l) Transmission Integrity Programs

Figure F-8-1: Age of Transmission Pipe has been increasing



One half of the total mainline transmission pipeline length is over 40 years old. The level of expenditure required to operate and maintain older segments to the required standard of safety and reliability has grown due to the need for selective asset replacement or repair, as identified by regularly scheduled internal inspections and assessments of pipe condition. Figure F-8-1 displays the number of kilometers and age of Transmission pipelines on the TGI system.

For increased patrols, vegetation management, permit work, integrity management plan upkeep, and cyclical increases for station painting, NDT/HVT testing Transmission requires an increase of $36 thousand for 2010.

For 2011, TP activity is first budgeted irrespective of what will land in capital due to IFRS rules[3]. This causes a readjustment to O&M of $1.151 million which is later offset by a shift of ($626 thousand) back to capital, with the remaining increase due to increases in integrity studies, inspections, seismic hazard management, in line inspections and rehab programs.

(m) Valve Maintenance

Valves are used to control the flow of natural gas and are inspected regularly to ensure their availability for use during an emergency. Critical valve repairs were completed during the period of 2004 through 2009 as required. Other repairs judged non-critical at the time were deferred as the associated risk permitted. The risk associated with leaving the repairs any longer is considered unacceptable. Distribution requires increased funding of $200 thousand in order to perform the outstanding repairs.

Critical valve maintenance will ensure the continued safe, reliable and cost effective delivery of natural to customers while also ensuring the valves will operate correctly when they are required in an emergency.

(n) Vegetation Management

CSA Z662 requires vegetation on rights-of-way shall be controlled to maintain clear visibility from the air thereby reducing the probability of third party damage and encroachments and also to provide for ready access for maintenance crews. Efforts have been made to defer or minimize vegetation control to validate the frequency; however, experience during the period of this examination has indicated that a five year cycle is required. Additionally, changes in environmental regulations put additional pressures on vegetation management programs (e.g. work near streams, bird nesting season limitations, fire protection seasons). These restrictions increase costs by requiring an accelerated schedule during the relatively brief times available to perform the work.

For ongoing vegetation management, Distribution requires incremental funding of $175 thousand starting in 2010 and $50 thousand in 2011. Terasen Gas will continue to meet Code requirements and conduct programs in an optimum fashion to ensure public, plant and employee safety; vegetation management on Terasen right of ways is one of those programs.

The Federal Pest Control Act and the Provincial Weed Control Act require that we have formal vegetation management programs in place to manage noxious weeds along our ROW and on all our properties. External costs associated with this program are increasing by $15 thousand in 2010. We request that the Engineering budget within B&ITS be increased by this amount.

[3] See Application, Part III, Section C, Tab 11 for IFRS rules.

(6) CONCLUSION

Terasen Gas believes it is critical to continue focus integrity and asset management to ensure safe, reliable, and cost effective operations. The process of developing and implementing the Terasen Gas Integrity Management Plan has allowed the company to review and confirm its integrity programs and activities. As a result of this review, areas of improvement were identified. As well, pressures such as inflation, system growth, community encroachment and new code requirements are driving the costs identified above. Terasen believes these costs are necessary and prudent.

d) CSA Z662 - Annex A: Safety & Loss Management

(1) INTRODUCTION

The Canadian Standards Association (CSA), with input from industry, is shifting the long term direction of Canadian pipeline regulation to make it more performance based and less prescriptive. This shift is evident throughout CSA Z662 and continued to be reinforced through the introduction of Annex N and M in 2006. In 2007, a new clause (10.2) was added to the Operating, Maintenance, and Upgrading section of CSA Z662 that moves industry further towards performance based regulation. We are required to respond to this new regulation and need increased funding starting in 2010 to implement and manage our coordinated compliance with key sections of CSA Z662 related to performance based regulation.

Clause 10.2.1 states that

> *"Operating companies shall develop, implement, and maintain a documented safety and loss management system for the pipeline system that provides for the protection of people, the environment, and property[4]".*

Clause 10.2.2 then proceeds to provide the details of the elements that should be included in a loss management system and also refers to Annex A for an extensive guideline for the same. We have many disparate programs and management systems across the organization that exist to meet specific requirements of various regulations. For example, we have an Environment Management System, a Natural Hazards Management Program, a Vegetation Management Program, and others. Clause 10.2.2, Annex A, N & M are similar (yet ever so slightly different) in their requirement for companies to have a holistic and integrated approach with their various systems and programs. We need to ensure that our systems contain the appropriate elements, are aligned and integrated, and that they are producing the appropriate outcomes to allow us to demonstrate compliance with the various sections of CSA Z662. Terasen Gas is in the process of accessing potential compliance gaps to this new requirement, but

[4] CSA Z662-07

already has several practices in place. To continue this analysis and to implement resulting changes, incremental funding is required.

The management systems approach implemented as part of Terasen Gas' Integrity Management plan will be used as the Company assesses Annex A requirements in 2009 and implements any necessary changes in 2010. Transmission requires an incremental funding of $250 thousand starting in 2010 to perform anticipated changes to conform to clause 10.2.1 of CSA Z662-07.

Terasen Gas is a leader in the area of emergency planning and security for the Province of British Columbia. Many employees participate in regular corporate emergency exercises with relevant government and non-governmental agencies in the Province of British Columbia. The Company has adopted a four-year rolling exercise cycle to ensure our systems and resources are adequate to respond to small and large scale emergencies, including earthquakes and pandemics.

Three areas require incremental funding in 2010: emergency preparedness, mobile radios and business continuity planning. These are presented below.

(2) EMERGENCY PREPAREDNESS

Emergency preparedness is fundamental to any safety and loss management system. Three areas which require incremental funding are: emergency response, mobile radio network, and business continuity.

(a) Emergency Preparedness

Terasen Gas is committed to being prepared to respond effectively to major disaster incidents by supporting a comprehensive emergency preparedness program. Emergency planning with a focus on business continuity strengthens the Company's ability to ensure the continual functioning of critical business elements in the event of a technology failure or pandemic. The need to maintain, augment and fortify Terasen Gas' existing plans and response strategies is three-fold: dependency on lessons learned, current standards and dependency on technology.

(i) Lessons Learned

The opportunity to review the lessons learned from events such as 9/11, Hurricane Katrina and the Northeast Blackout of 2003 demonstrate the need for prompt response and recovery of critical infrastructure and the reliance of business processes on other, external critical infrastructure and internal IT recovery. The partial activation of Terasen Gas' emergency plans during the 2007 Fraser River Freshet Flood risk and the recent escalation of the World Health Organizations pandemic risk level from a Phase 3 to a Phase 5 have demonstrated the strength of our emergency preparedness and plans. These events have also exposed the need to continue to enhance, augment and update our established strategies and the need to implement additional processes and approaches. With continual improvements and additions Terasen can ensure the utility is able to respond promptly to make safe, resume the delivery of energy to our customers and continue core business functions if a large scale event were to occur.

Municipalities, External Agencies and the Province are increasing, and expecting, a collaborative approach to emergency planning, event response and overall public safety. As evidenced from the security and consequence management planning for the Olympics and during other provincial incidents in the recent years, external agencies are requesting Terasen to engage in advance planning; to participate in situation awareness and monitoring communications and to partake in multi-agency exercises. These activities prepare Terasen and partner agencies for an integrated, cohesive and safe approach to response and recovery in disasters, but require resources to contribute to the planning, activating and completion of actions.

(ii) Standards

Terasen Gas tests compliance with regulation and applicable codes of practice by regularly auditing its overall emergency preparedness program and individual departmental emergency plans. We are confident that the overall program currently complies with regulatory requirements and incorporates industry leading practices. New and upcoming standards and practices have been identified and will, where necessary, require components to be incorporated into the emergency preparedness program in the next two years. Currently, emergency management and business continuity standards are not legislated in Canada, but reference to them appear to have established an expectation of due diligence.

The American "9/11 Commission Final Report" recommends that the National Fire and Prevention Association (NFPA) Standard 1600: *Disaster/Emergency Management & Business Continuity* be adopted by the private sector. The Commission states that compliance with the NFPA Standard should define the standard of care owed by a company to its employees and the public for legal purposes[5]. The Canadian equivalent, Standard Z1600: *Emergency Management and Business Continuity* by the Canadian Standards Association has recently been issued. Currently, the Canadian Standards Association is in the midst of developing a consensus on the need and scope of a new standard on Emergency Management for Petroleum and Natural Gas Industry Systems.

(iii) Dependency on Technology

Terasen Gas recognizes the need to be able to respond to business interruption, regardless of the event. Loss of or access to applications and data for an extended period of time has been identified as a significant exposure to the organization that needs to be addressed. The majority of the energy and utility industry have formal IT / disaster recovery plans but there is a significant effort in coordinating

[5] The 9/11 Commission Report, page 398

the alignment of emergency planning, business continuity and disaster recovery. Terasen is lagging in this area. That said, there are some business units that have implemented Point Solutions to address their individual recovery requirements but when assessed at a corporate level do not meet the organizations overall recovery needs.[6] Business applications that have some level of recovery include AM/FM, WINS, Nucleus and SAP. Under the ownership of Kinder Morgan, the direction was to utilize the existing Kinder Morgan data centres and support staff for a formal Disaster Recovery site, providing significant cost reductions in capital and operating expenses. With the sale of Terasen to Fortis, that opportunity is no longer available. Now Terasen has to undertake initiatives to fortify our Disaster Recovery. The scope of the exercise is to provide for technology disaster recovery and business continuity in the event that the data centre is lost, a Terasen facility is inaccessible, or both.

Terasen's emergency preparedness program is not static. Lessons learned from others, emerging risks, up and coming standards and industry codes of practice and the continual improvement of plans and strategies requires resources. The continuing development of emergency preparedness will provide Terasen the guidance and strategies to safely, effectively and efficiently mitigate, respond and recover in the event of a major disaster. Not maintaining current programs or proceeding with the proposed initiatives will likely result in continued inefficient use of resources, gaps in our preparedness system, an inability to meet recommendations flowing from exercise reviews and standards. A strong emergency preparedness program and fulfilled project initiatives supports the Operational Excellence Terasen Gas strives for in the safe, efficient and reliable delivery of natural gas to homes and businesses throughout BC.

To strengthen emergency preparedness, an incremental $115 thousand is required starting in 2010 to the HROG budget.

(b) Emergency Preparedness – Mobile Radio Network

Terasen Gas has currently deployed a mobile radio network throughout its coverage territory within the British Columbia Interior and Lower Mainland but has not deployed this capability along the corridor between Squamish and Whistler or on Vancouver Island. As such, this application recommends Terasen Gas expand its mobile radio network to Whistler during 2009 and to Vancouver Island in 2011. We believe that expanding our mobile communications network throughout the entire coverage territory of Terasen Gas, will provide a common platform for emergency backup communications throughout the

[6] i.e. SAP recovery provides financial statements but would not support all of Finance nor any other business process utilizing it, AMFM has limited network bandwidth which would limit number of people able to access it, etc.

province that is essential to support the safe and reliable delivery of gas service to all customers in a cost effective manner.

Provided below is a description of the deficiencies associated with the current emergency communications system for TGW and TGVI and the justification for addressing the system at this time.

In an emergency situation, the need for communications is critical to ensuring the initial response and the subsequent continuation of service is done in a manner that is timely and cost effective, and above all, preserves the safety of both the public and the employees. However, the current cellular network used for communications within TGW and TGVI does not have adequate coverage throughout these two regions. Furthermore, the supplier can not provide assurance that cellular communications will be available in a widespread emergency. As such, the risk profile is significantly increased in these regions as any loss in cellular service during an emergency may result in a reduced ability to respond to immediate threats to the public or employees. In addition, the inability for the field to communicate efficiently may produce delays that would prevent customers from receiving gas service for extended periods of time. This may result in significant hardship to customers depending upon the season and their access to alternative energy solutions. Looking forward, the supplier of the cellular phones does not forecast significant increases in adoption rates for this technology and therefore the business driver is not present to address the concerns related to inadequate coverage and cellular availability during emergencies within the foreseeable future.

As such, we believe expanding the current mobile radio network at this time is prudent and required given the anticipated reliability of the radio network system during emergency situations and the cost efficiencies that currently exist related to having a fully deployed mobile radio network and associated overhead already in place. The incremental BAIT funding requirement required starting in 2010 is $25 thousand with and additional incremental amount of $100 thousand in 2011.

(c) Business Continuity

The need to enhance and unite existing plans with disaster recovery strategies into a formal business continuity program at Terasen is required now because of the Company's dependency on technology, past learnings and current standards.

Recommendations from the Disaster Recovery Strategy Report produced in 2008 include the implementation of an alternate site recovery strategy, establish a virtual workplace and implement a formal business continuity program. The program would provide governance, integration, validation and sustainability of the disaster recovery strategies and their collaboration with business continuity plans.

Business continuity is part of an integrated organizational preparedness program. It is a component of the corporate emergency plan and the corporate emergency plan leads the business continuity plans.

Recommended components of a business continuity program include:

- Corporate ownership through an executive sponsor;
- A Business Continuity Manager (or designated lead) to liaise and coordinate activities corporately and within the business units;
- A business continuity management system designed according to industry standards and best practices;
- Controls for the maintenance of continuity plans;
- Incorporation of business continuity mitigation strategies, such as IT recovery, into new project plans;
- Integration of business continuity into the corporate emergency planning program; and
- Validation of business continuity plans and strategies.

It will take three to five years to establish a comprehensive business continuity program at Terasen. This will take place only through the implementation of disaster recovery strategies and the design of robust business continuity plans for each business group.

Successful development and sustainability of a business continuity program requires a dedicated leader. At present, only minimal support is available to lead such a program from the IT and EH&S groups.

The creation of a Business Continuity Manager role would centralize responsibility for all aspects of the organization’s business continuity program. The role would:

- Develop and implement the business continuity management system;
- Maintain the program and related documentation;
- Monitor applicable laws and regulations and adjust the organization’s methodology accordingly to remain in compliance;
- Promote consistency across the organization;
- Promote process improvement opportunities;
- Ensure business continuity is part of any new Terasen project;
- Integrate business continuity with other preparedness planning;
- Ensure the IT disaster recovery plan is part of any business continuity plans;
- Validate plans with testing and exercises; and
- Incorporate the concept of business continuity into Terasen's safety culture.

(d) Pandemic Planning

Another component of business continuity is pandemic planning. The World Health Organization estimates the probability of a world wide pandemic event to be between 25 and 65 percent by the year 2017. The event is likely to be an influenza virus, generating illness in people by affecting their respiratory tracts. The pandemic will spread easily and rapidly through many countries and regions of the world, affecting a large percentage of the population in the areas affected. The disease will spread around the world in less than eight weeks, and employee absenteeism is predicted at 40 percent or higher. Employees may be absent from work because they have either contracted the virus, need to care for family members (including children) who have become sick or died, or are worried that they may become sick.

Terasen Gas, like every other business, has plans to accommodate minor temporary vacancies in its workforce due to sickness, vacation, job turnover, and other types of absences. However, the risk of a world wide pandemic raises concerns that a significant number of Terasen's employees will not be available to perform their jobs for an extended period of time. The sheer number of people potentially absent during a pandemic, combined with the absence of key staff, requires that Terasen be well-prepared for the occurrence of such an event.

Terasen Gas has been proactive in working with industry groups and health agencies to develop a corporate pandemic plan which identifies prevention strategies to mitigate the impact of a pandemic on the business, and also respond to a pandemic in a way that minimizes impact on our employees, customers and shareholder.

The objectives of pandemic planning are to:

- Ensure the Company is capable of adequately responding to emergencies;
- Ensure critical business operations continue;
- Minimize employees' and customers' exposure to infection;
- Effectively communicate with employees, customers, regulators and other stakeholders; and
- Assist with responses to pandemic issues in the broader community at the direction of provincial authorities.

The Terasen Gas Pandemic Plan was developed during 2008 and is consistent with the World Health Organization and both national and provincial Pandemic Health Plans. The plan seeks to achieve the objectives of pandemic planning by defining preparedness and mitigation strategies thereby:

- Organizing Terasen to appropriately respond to a pandemic;
- Assessing risk to employees and Terasen business;

- Protecting employee health;
- Preparing guidance documentation, including standards and work procedures;
- Planning for business continuity;
- Preparing a communications plan; and
- Striving for the continuation of Company programs as appropriate.

Terasen's approach to pandemic planning is driven by WorkSafe BC Regulations requiring the development and implementation of exposure control plans and Terasen's Environment, Health & Safety Policy. This policy states, in part, that Terasen is committed to identifying and managing risks to prevent or reduce possible adverse consequences from our operations and integrating environmental, health, safety and security protection measures into all elements of our business.

To achieve these policy objectives, Terasen is guided by the following principles:

- The risk of a large-scale employee absence needs to be identified, assessed and controlled to acceptable levels;
- Response to a pandemic event needs to be regularly exercised; and
- Terasen needs to integrate and align pandemic planning within a broader context of business continuity management and emergency preparedness.

Terasen's pandemic planning will continue to evolve as more information on the risks and impacts of a pandemic event are made available. Pandemic contingency plans will be reviewed and strengthened through participation in both internal and external exercises.

During 2010 and 2011, further pandemic mitigation strategies will include the integration of pandemic contingency plans with business continuity plans.

(3) CONCLUSION

To achieve the identified changes to the business continuity and pandemic programs, an increase of $315 thousand for HROG is required in 2010, with $225 thousand continuing into 2011.

e) CSA Z1000 – Safety Management System and WorkSafeBC

The health and safety of our workforce and the public are critical elements in the road to achieving operational excellence. Terasen incorporates employee health and safety into every element of our business as discussed in more detail in Part III, Section, Tab 1, The Past.

Occupational health and safety provincial regulations are set by WorkSafeBC. CSA Z1000 is a suggested framework for an occupational health and safety management system. Annex A of CSA Z662 also touches on OH&S management systems. The Company believes that Annex A OH&S requirements will be addressed if CSA Z1000 is implemented, and that the Z1000 framework will strengthen its current policies and standards. To this end, increased funding is required in B&ITS in the amount of $11 thousand.

f) Environmental Management Act – Environmental Programs

The public and governments have placed a high focus on environmental protection. British Columbia places a high value on ensuring environmentally sound practices as demonstrated by its Environmental Management Act which includes significant penalties for non-compliance In terms of environmental management.

The Company conducts its business in a safe and environmentally responsible manner that includes dealing fairly, openly and honestly with stakeholders and communities to ensure our activities have no lasting ill effects on the natural environment.

Terasen also works with communities and stakeholders to protect the environment through our Environmental Community Outreach program. This program provides opportunities for our employees to participate in community-based environmental activities that enhance fish and wildlife habitat in our service areas.

(1) ENVIRONMENTAL MANAGEMENT SYSTEM

Terasen is committed to the philosophy that sound safety and environmental practices make good business sense. Terasen's success in the area of environmental management is based in part on developing and maintaining an effective Environmental Management System that is compliant to ISO 14001 Environmental Management Systems standard.

The Environmental Management System provides guidance to the Company, its employees, and its contractors on how to comply with all applicable environmental laws, Company policies and industry codes of practice. Audits, inspections and incident investigations drive monitoring and system improvements through the Environmental Management System. Corrective actions identified in audits, inspections and incident investigations are used to improve the system and minimize the risks.

To meet federal regulatory requirements for species at risk, Terasen Gas plans to develop and implement a planning process that identifies those species at risk that may be impacted by our proposed operations. This process may involve mapping that integrates with AM/FM to identify potential areas of concern for at risk species. This will allow Terasen Gas to effectively protect these species and meet regulatory requirements when operating and maintaining existing pipelines and planning new gas line construction and will:

- Facilitate project permitting and approval processes;
- Minimize construction interruptions; and
- Ensure regulatory compliance.

Terasen Gas plans to meet provincial and federal regulatory requirements and industry best practices by developing an overall waste management strategy that will:

- Streamline project permitting and approval processes;
- Avoid costs associated with unnecessary agency applications and waste authorization permitting; and
- Ensure regulatory compliance

To build these programs, increased funding within the EH&S group of HROG is required with a sum of $90 thousand in 2010, of which 70 thousand continues into 2011.

g) Power Engineers and Boiler and Pressure Vessel Safety Act

There are a number of pressure vessels installed in the Terasen natural gas distribution system. Previously pressure vessels have been considered a part of the piping system and treated accordingly. Improved understanding of Code requirements has indicated that this treatment of the pressure vessels is not in compliance. An incremental $220 thousand for 2010 is required within Distribution.

Implementation of this program will bring Terasen Gas into regulatory compliance and ensure the ongoing safety of the public, Terasen Gas plan and employees. Assets are to be registered with the BC Pressure Vessels branch, data files to be set up and inspections carried on a periodic basis per API 510 and the safety authority.

<u>Conclusion</u>

To ensure ongoing compliance to existing codes and anticipated new or changed codes, additional operating and maintenance funding is required. Reasons for the requested increase include inflation, growth, asset age and new or enhanced code requirements. The incremental funding requirements are necessary and prudent.

Appendix G

ENERGY EFFICIENCY AND CONSERVATION AND ALTERNATIVE ENERGY SOLUTIONS

(view Attachments Panel in Adobe

to access Contents of Appendix G)

Appendix H

ACCOUNTING AND OTHER POLICIES

International Financial Reporting Standards (IFRS):

A Summary of Anticipated Impacts of Transition to IFRS on Rate Regulated Utilities in British Columbia

10 June 2009

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1.0 Introduction

1.1 Background

The financial records of publicly accountable utilities in British Columbia that are regulated by the British Columbia Utilities Commission (Commission) are maintained in accordance with Generally Accepted Accounting Principles (GAAP) and are audited by independent public accounting firms. As GAAP moves from Canadian standards to IFRS, those utilities will adapt their financial records to meet the requirements of the new standards. There are a number of differences between IFRS and current Canadian GAAP which could have material impacts on the accounting values reported in those financial records. In addition, since IFRS, like Canadian GAAP, is principles-based, how specific utilities interpret and implement the standards may differ.

These impacts can be summarized under three categories. With the exception of the third category, the changes from Canadian GAAP to IFRS do not affect total costs to be recovered from ratepayers, but the standards do change the timing of when those costs might be recovered in rates.

(a) Transitional adjustments

For financial statement purposes, the transition to IFRS will result in adjustments to a utility's opening retained earnings. The impact of those adjustments on future rates needs to be determined.

(b) Ongoing differences

Ongoing differences in the timing of recognition of certain transactions under IFRS will result. This could give rise to short-term volatility in rates and/or earnings, depending on the use of deferral accounts.

(c) Additional costs

Costs will arise in connection with the conversion itself and may include additional internal resources, external consulting and IT systems costs. In addition, ongoing compliance costs may increase due to additional reconciliation and assurance requirements, including external audit fees due to assurance over new disclosure and the duplicate audit opinion required for 2010 (includes Canadian GAAP opinion in 2010 and IFRS opinion for current and comparative 2010 year for 2011).

IFRS adoption will be required for publicly accountable utilities for the first fiscal period beginning on or after January 1, 2011, with comparative amounts for the prior year restated to be compliant with IFRS. As a result, utilities will only be able to provide regulatory schedules prepared under IFRS for this comparative year and going forward. The availability of the 2010 comparative IFRS financial statements will vary among utilities. At a minimum, the 2010 comparatives will be available in 2011 as required. There will also be transitional adjustments to meet the requirements of IFRS 1 First Time Adoption of IFRS. The timing of when utilities may seek to recover these differences may vary depending on the timing of their own revenue requirements applications and the materiality of each item to each utility.

1.2 Purpose

The purpose of this report is to provide a summary of those differences between Canadian GAAP and IFRS that have been identified by the Utilities IFRS Working Group (described below) as having the most significant impact on regulatory accounting and rate making. This summary could then be referred to by the utilities in their various filings and related discussions on IFRS accounting impacts.

The Utilities IFRS Working Group was created as a venue for discussion of IFRS issues, evaluation of alternatives, and how those alternatives could be implemented in the financial systems, accounting practices, and regulatory practices of the member utilities. The utilities involved in the Group are BC Hydro, BC Transmission Corporation, FortisBC, Terasen Gas, and Pacific Northern Gas.

1.3 Limitations

This report should only be used for the purpose set out above, and is intended for use as information by the accounting, financial and regulatory personnel of the utilities in the Utilities IFRS Working Group, Commission staff, and intervenors or other interested parties. It should be noted that the individual utilities in the Utilities IFRS Working Group may not adopt all interpretations in this document.

The following matters have been specifically excluded from the report:

(a) Recommendations by the Utilities IFRS Working Group on which IFRS alternative is preferred;

(b) Discussion of how these IFRS changes may be implemented in revenue requirements applications and other filings;

(c) A comprehensive discussion of all IFRS changes, many of which may have an impact on some utilities. See Appendix A for an extract from the website of the Canadian Institute of Chartered Accountants, which compares IFRS to Canadian GAAP and includes a listing of the individual standards and interpretations.

As with all accounting standards, IFRS will continue to evolve over time, whereas this document has been prepared as of the date specified on the cover title page and each section will be updated as required. For pending changes to standards and major projects, the International Accounting Standards Board (IASB) has prepared a work plan outlining its estimate of document publication dates. See the table below for a summary of those standards and interpretations expected to change in the next two years.

Table 1. Summary of Standards and Interpretations Expected to Change in the Next Two Years

	Changes Likely To Be Available Before the End of 2009	Changes Likely To Be Available In 2010 - 2011
1	Group Cash-settled Share-based Payment Transactions (Q2 2009)	Financial Instruments (2010)
2	Joint Ventures (Q3 2009)	Fair Value Measurement Guidance (2010)
3	First-time Adoption of IFRS (Q3 2009)	Income Taxes (2010)
4	Related Party Disclosures (Q3 2009)	Rate-regulated Activities (2010)
5	Discontinued Operations (Q4 2009)	Earnings per Share (2010)
6	Consolidation (Q4 2009)	Management Commentary (2010)
7	Emissions Trading Schemes (Q4 2009)	Derecognition of Financial Assets (2010)
8	Liabilities (Q4 2009)	Financial Statement Presentation (2011)
9	Financial Instruments - Characteristics of Equity (Q4 2009)	Insurance Contracts (2010)
10		Leases (2011)
11		Post-employment Benefits (2011)
12		Revenue Recognition (2011)

This document will be updated periodically to reflect the issuance of new standards or interpretations, but cannot be assumed to reflect current IFRS at any point in time.

The following sections summarize the IFRS impacts that are relevant to those items that are generally included in the rate-setting methodology. Some utilities earn a return based on capital structure, while others earn a return on rate base. Depending on the rate-setting methodology of the individual utility, the application of accounting standards under either Canadian GAAP or IFRS could have different impacts.

Throughout this document references are made to applicable Canadian GAAP and IFRS sections. Canadian GAAP and IFRS references should be read as the section followed by the paragraph number. For example, "CICA 3061.16" should be read as section 3061, paragraph 16, of the CICA Handbook. It should be noted that the IFRS references include "IFRS", "IAS" and "IFRIC" sections. These three should be read in a similar format as Canadian GAAP with the standard or interpretation number followed by the paragraph number. For example, "IAS 23.8" should be read as standard number 23, paragraph 8, of the International Accounting Standards.

International Accounting Standards (IAS) were issued by the predecessor body of the IASB, the International Accounting Standards Committee (IASC) prior to 2002. Since that time, the IASB has issued IFRSs, although both have the same authority. Interpretations issued by the International Financial Reporting Interpretation Committee (IFRIC) are essentially additional guidance or interpretations provided on newly identified financial reporting issues not specifically addressed in IASB Standards. IFRICs are analogous to interpretations issued by the Emerging Issues Committee (EIC) under Canadian GAAP.

2.0 Regulatory Assets and Liabilities (Deferral Accounts) (updated 30 April 2009)

The use of deferral accounts is a recognized component of rate making, allowing costs and revenues to be matched and streamed to ratepayers over the period to which they relate, to allow for reduced exposure to volatility in rates, and to neutralize or dampen the impacts of forecast error on items that the utility has little or no control over.

2.1 Canadian GAAP

Based on standards issued as of: April 30, 2009

Effective January 1, 2009, Canadian GAAP was revised to remove a temporary exemption from applying Canadian GAAP to the recognition of assets and liabilities resulting from rate regulation (CICA 1100.32B). In the absence of guidance available under Canadian GAAP, rate regulated utilities in Canada are permitted to apply US Statement of Financial Accounting Standards No. 71 *Accounting for the Effects of Certain Types of Regulation*, which allows the recognition of rate regulated assets and liabilities under the following circumstances.

(a) The enterprise's rates for regulated services or products provided to its customers are established by or are subject to approval by an independent, third-party regulator or by its own governing board empowered by statute or contract to establish rates that bind customers;

(b) The regulated rates are designed to recover the specific enterprise's costs of providing the regulated services or products;

(c) In view of the demand for the regulated services or products and the level of competition, direct and indirect, it is reasonable to assume that rates set at levels that will recover the enterprise's costs can be charged to and collected from customers. This criterion requires consideration of anticipated changes in levels of demand or competition during the recovery period for any capitalized costs.

2.2 International Financial Reporting Standards

Exposure Draft expected: July 2009
Rate-regulated Activities final standard expected: During 2010

Currently, IFRS do not explicitly recognize the economic effect of rate regulation through the existence of deferral and variance accounts, unlike US standards. Instead, individual accounts should be assessed under the International Accounting Standards Board's Conceptual Framework to determine if they meet the definition of an asset or a liability.

However, in July 2009, the International Accounting Standards Board (IASB) is expected to issue an Exposure Draft on Rate-regulated Operations, which if issued as a standard would allow recognition of these deferral and variance accounts under certain circumstances. There are a number of steps for the Exposure Draft to go through before it becomes a Standard, as illustrated in the following table. The publication of the final standard is not expected until June 2010, and until that time any of the recommendations included in preliminary discussions or drafts will be subject to change.

Table 2. Project Milestones

	Date	Project Milestone
1	April 2009	Major decisions finalised
2	May 2009	Pre-ballot draft provided to Board members
3	June 2009	Board meeting to discuss remaining technical issues and any other sweep issues
4	July 2009	Publication of Exposure Draft with 120-day comment period
5	November 2009	Comment Letter due date
6	January 2010	Begin re-deliberation of Comment Letter analysis
7	June 2010	Publication of final standard
8	January 2011	Effective date

The Exposure Draft would be confined to those rate-regulated entities that meet the following criteria:

(a) Where an authorized body is empowered to establish rates that bind customers;

(b) Where the rate regulation takes the form of cost-of-service regulation.

Further, for a cost to be included in the determination of rates, it must be "allowable". Allowable costs are usually defined as actual or estimated costs for which revenue is intended to provide recovery. Allowable costs include interest costs and a reasonable return on shareholders' investments (Allowance for Funds Used During Construction).

At the Board meeting in April, the Board discussed recognition and measurement, presentation and disclosure and additional scope issues of this project. The following is an extract of the meeting summary from the IASB website.

> "Recognition and measurement
>
> The Board tentatively decided that assets and liabilities recognized as a result of rate regulation should be excluded from the scope of IAS 38 Intangible Assets and IAS 37 Provisions, Contingent Liabilities and Contingent Assets respectively. Once the entity has determined that its activities are in the scope of the project, the effects of rate regulation should be recognized, therefore there is no requirement for specific recognition criteria.
>
> The Board decided tentatively that a probability-weighted average of possible future cash flows should be used to measure assets and liabilities recognized as a result of rate regulation both on initial recognition and at each subsequent reporting date.

Presentation and disclosure

The Board decided tentatively that regulatory assets and liabilities should not be offset in the statement of financial position. Additionally, when an entity presents a classified statement of financial position, it should distinguish between current and non-current assets and liabilities recognized as a result of rate regulation.

Additional scope considerations

The Board agreed tentatively with the staff recommendation that the standard should include guidance on the application of the scope criteria.”

3.0 Property, Plant and Equipment - Valuation (updated 30 April 2009)

Amounts recognized as Property, Plant and Equipment (PP&E) under IFRS can differ from current Canadian GAAP both at the time of initial adoption and after transition to IFRS.

3.1 Initial Adoption of IFRS

Based on standards issued as of: April 30, 2009
Exposure Draft Additional Exemptions for First-time Adopters issued: September 2008
IFRS 1 final amendments expected: Q3 2009

First time adoption of IFRS generally requires that a company restate its results as if IFRS accounting policies have always been applied (IFRS 1.10, IFRS 1.11). For most utilities that have been providing service to customers for many years, it would be an extremely costly and time-consuming, if not impossible, task to restate as many as fifty or sixty years of transactions to be compliant with IFRS. For this reason, there are exemptions to this requirement under IFRS 1, specifically for items of PP&E:

(a) On transition to IFRS, a utility may elect to measure PP&E at its fair value and use that as its deemed cost (IFRS 1.30, IFRS 1 D5).

(b) A proposed exemption, that a rate regulated utility may use historical carrying value of property, plant and equipment as its deemed cost on transition, if it is **impracticable** to determine the fair value or to restate historical costs for IFRS. This exemption may be extended to apply to those intangible assets that had been classified as PP&E prior to adoption of the IFRS-compliant Handbook Section 3064. (Exposure Draft issued September 2008 Additional Expemptions for First-time Adopters)

Table 3. On Transition PP&E: Alternatives and Implications

	Alternative	Implications for Utilities
1	Historical Cost	No conversion activities necessary
2		Availability dependent on meeting the requirements of the final IFRS 1 exemption which is not yet approved
3	Retrospective Restatement	Significant time and effort required to identify and segregate the non-compliant historical costs
4		Transition differences to be addressed
5	Fair Value	Significant time and effort required to determine fair value
6		Transition difference to be addressed

Although most utilities would elect to use historical carrying value as deemed cost on transition if possible, the current wording of the proposed exemption is problematic. Comments have been provided back to the standard setters on two issues. One is to seek clarification of the word “impracticable” and the other is to determine if the proposed exemption would extend to items that were previously recognized as PP&E under Canadian GAAP but have since been classified as Intangible Assets (items such as computer software, rights of way).

On transition utilities will be required to perform an impairment test and record any impairment losses that may exist at that date.

3.2 After Transition to IFRS

3.2.1 Canadian GAAP

Based on standards issued as of: April 30, 2009

Under Canadian GAAP, PP&E is recorded based on actual historical costs (CICA 3061.16), which at any point in time represents many years of capitalized costs and applied depreciation policies.

3.2.2 International Financial Reporting Standards

Based on standards issued as of: April 30, 2009

Under IFRS, a company has the option of choosing either the cost model or the revaluation model for valuation of property, plant and equipment (IAS 16.29). Under the cost model, PP&E is carried at cost less accumulated depreciation and accumulated impairment losses. Under the revaluation model, where the fair value of PP&E can be measured reliably, that item can be carried at fair value less any subsequent accumulated depreciation. The appropriate method of measuring fair value may require the use of professionally qualified valuators.

Table 4. PP&E Valuation: Alternatives and Implications

	Alternative	**Implications for Utilities**
1	Cost model	Status quo
2	Fair value model	Effort to maintain and update fair value records
3		Difficulties in determining fair value
4		Increased volatility in rate base and reported earnings
5		Possible multiple sets of books

4.0 Property, Plant and Equipment - Capitalization (updated 30 April 2009)

4.1 Capitalization of Overhead Costs

4.1.1 Canadian GAAP

Based on standards issued as of: April 30, 2009

Currently, utilities report PP&E based on cost plus an element of general and administrative expenses (CICA 3061.20), some of which is applied to PP&E through an overhead capitalization rate, and some of which is directly charged to capital through internal accounting processes.

4.1.2 International Financial Reporting Standards

Based on standards issued as of: April 30, 2009

In the future, IFRS requires that additions to PP&E continue to be recorded at cost, but has further defined cost to include only items that are **directly attributable** to the asset (IAS 16.16b). Therefore, costs related to administration and general overhead would be excluded (IAS 16.19d).

Utilities will be required to evaluate all costs that are currently capitalized to determine if they meet the definition of "directly attributable".

4.2 Capitalization of Borrowing Costs

4.2.1 Canadian GAAP

Based on standards issued as of: April 30, 2009

Under current GAAP, carrying costs, such as interest, that are directly attributable to the construction of an asset may be capitalized (Interest During Construction or IDC) (CICA 3061.23). Utilities are alternatively allowed to capitalize an allowance for funds used during construction (AFUDC) (CICA 3061.23).

4.2.2 International Financial Reporting Standards

Based on standards issued as of: April 30, 2009

Under IFRS, borrowing costs that are incurred in relation to an asset that takes a substantial period of time to get ready for use, are **required** to be capitalized (substantial period of time being a subjective definition and will likely vary across utilities) (IAS 23.8). AFUDC is not allowed to be capitalized, since it contains an equity component (IAS 23.6). However, it appears that AFUDC may be allowed to be recognized under the proposed Exposure Draft on Rate-regulated Operations.

4.3 Other Capitalization Differences

Canadian GAAP allows judgment and policy choices in the capitalization of certain costs. In contrast, IFRS is more explicit and specifically requires the capitalization of a number of other items, which include:

(a) Capitalization of depreciation on assets used in construction (IAS 16.49);

(b) Capitalization of the current service cost component of pensions and employee future benefits (IAS 16.17a);

(c) The point where capitalization stops, being when an asset is available for use rather than put into use (IAS 16.55). See section 7.2(a) for further details on commencement of depreciation, definition of available for use, and additions to plant.

5.0 Property, Plant and Equipment - Other Items (updated 30 April 2009)

There are a number of aspects of PP&E that are afforded different treatment under IFRS than under Canadian GAAP. These primary differences are:

(a) Gains and losses on disposal of assets;

(b) Customer contributions;

(c) Asset retirement obligations.

5.1 Gains and Losses on Disposal of Assets

5.1.1 Canadian GAAP

Based on standards issued as of: April 30, 2009

Under Canadian GAAP, rate-regulated utilities are allowed to defer any gain or loss arising on disposal of assets if it is to be considered in the determination of future rates charged to customers. The gain or loss is deferred, either through accumulated depreciation or a deferral account, and not immediately recognized in the income statement (CICA 3475.26).

5.1.2 International Financial Reporting Standards

Based on standards issued as of: April 30, 2009

IFRS requires that gains and losses on disposal of assets be recognized immediately in income, and cannot be charged or credited to accumulated depreciation for recovery in future depreciation rates (IAS 16.68).

5.2 Customer Contributions

5.2.1 Canadian GAAP

Utilities in British Columbia show contributions in aid of construction as contra assets (a credit to PP&E) or as a deferred credit, and amortize them as a reduction of depreciation over the life of the related item of PP&E.

5.2.2 International Financial Reporting Standards

Based on standards issued as of: April 30, 2009

Under IFRS, the customer contribution received is recognized as revenue in accordance with the obligation to the customer that underlies that transaction (IFRIC 18.13). The contribution is recognized as revenue either immediately or over a period of time such as a contract period or the life of the underlying asset (IFRIC 18.18 – IFRIC 18.20). Contributions not yet recognized as revenue are shown as liabilities (IAS 18.13).

5.3 Asset Retirement Obligations

5.3.1 Canadian GAAP

Based on standards issued as of: April 30, 2009

Under Canadian GAAP, an asset retirement obligation is recorded if a utility has a legal obligation to incur an expenditure in the future associated with the retirement of an asset currently in use (CICA 3110.03a).

5.3.2 International Financial Reporting Standards

Based on standards issued as of: April 30, 2009
Exposure Draft Liabilities issued: June 2005
Liabilities final amendments expected: Q4 2009

Under IFRS, asset retirement obligations (decommissioning and restoration obligations) are recognized for both legal and constructive obligations at the best estimate to settle the present obligation (IAS 37.25). Further information on the recognition and measurement of these obligations is contained in Section 6, Provisions, Legal and Constructive Obligations.

6.0 Provisions, Legal and Constructive Obligations (updated 30 April 2009)

6.1 Legal and Constructive Obligations

6.1.1 Canadian GAAP

Based on standards issued as of: April 30, 2009

Under Canadian GAAP, liabilities arise from predominantly legal or constructive obligations. These may relate to contractual arrangements, those derived from legal or statutory requirements, or inferred from the facts in a particular situation (CICA 1000.34).

6.1.2 International Financial Reporting Standards

Based on standards issued as of: April 30, 2009
Exposure Draft Liabilities issued: June 2005
Liabilities final amendments expected: Q4 2009

Under IFRS, liabilities can also arise from legal and also constructive obligations (IAS 37.14a). Constructive obligations arise where through an established pattern of past practice, policy, or specific statement, an entity has indicated to other parties that it will accept certain responsibilities (IAS 37.10). If a valid expectation is created whereby other parties expect the entity to discharge these responsibilities, then a liability will need to be recognized. IFRS also distinguishes a provision from other liabilities such as trade payables and accruals. The difference is related to the existence of uncertainty about the timing or amount of the future expenditure required to settlement of a provision (IAS 37.11). The concept of provisions under IFRS encompasses a wider range of circumstances that require recognition of liabilities than Canadian GAAP.

IFRS also discusses the concept of an onerous contract. These are arrangements where the unavoidable costs of meeting an obligation under the contract exceed the economic benefits to be received under it (IAS 37.10). For example, a Company is leasing an office building and decides to relocate to a new building. The lease on the old office building continues for the next four years and it cannot be cancelled and the Company cannot sublet it to another user. In this case a provision is recognized for the best estimate of the unavoidable lease payments.

These concepts of provisions and onerous contracts may potentially result in additional liabilities being recognized under IFRS.

6.2 Criteria for Recognizing a Provision

6.2.1 Canadian GAAP

Based on standards issued as of: April 30, 2009

Under Canadian GAAP, the probability threshold for recognizing a liability is whether the underlying event giving rise to the liability is likely to occur (CICA 3290.09) (commonly interpreted as 70% or greater).

6.2.2 International Financial Reporting Standards

Based on standards issued as of: April 30, 2009
Exposure Draft Liabilities issued: June 2005
Liabilities final amendments expected: Q4 2009

Under IFRS, the probability threshold for recognizing a liability or provision is whether the underlying event giving rise to the liability or provision is probable (IAS 37.14b) (commonly interpreted as greater than 50%) (IAS 37.23).

This is noticeably lower than the “likely” threshold under Canadian GAAP and could lead to additional provisions being recognized under IFRS.

6.3 Measurement of a Provision

6.3.1 Canadian GAAP

Based on standards issued as of: April 30, 2009

Under Canadian GAAP, liabilities are to be measured at management’s best estimate to settle. For contingent liabilities, a reasonable estimate is based on the most likely outcome of the ultimate loss. If no estimate is more likely than any other, then the low end of the range is used for estimating the potential loss (CICA 3290.13).

6.3.2 International Financial Reporting Standards

Based on standards issued as of: April 30, 2009
Exposure Draft Liabilities issued: June 2005
Liabilities final amendments expected: Q4 2009

Under IFRS, liabilities and provisions are also measured at management's best estimate to settle (IAS 37.36). Estimates subject to a range of possibilities are derived on an expected value basis. If no estimate is more likely than any other, then the mid-point of the range is used for estimating the potential loss (IAS 37.40). Under IFRS, the presumption that an estimate cannot be made is expected in only extremely rare circumstances (IAS 37.26).

As indicated in the timetable in Section 1.3, the IFRS standard on Liabilities is expected to be revised in the next two years.

7.0 Depreciation (updated 30 April 2009)

7.1 Canadian GAAP

Based on standards issued as of: April 30, 2009

Depreciation under Canadian GAAP follows these guidelines:

(a) Depreciation must be recognized in a rational and systematic manner over the estimated useful life of the asset (CICA 3061.28);

(b) Depreciation is allocated to the periods of service of an asset (CICA 3061.29). Canadian GAAP does not provide guidance on when the "period of service" begins to commence depreciation, however, a common policy choice is to commence depreciation on an asset when it is placed into service or is in use;

(c) The depreciation methods and estimates of the life and useful life are reviewed on a regular basis (CICA 3061.33), however, Canadian GAAP does not specify the frequency of a "regular basis";

(d) If an item of PP&E is made up of significant separable component parts, its cost must be allocated to the parts when practicable and when estimates can be made of the lives of the separate components (CICA 3061.30);

(e) Common practice to group assets and amortize them such that the combined cost of the assets is amortized over their estimated useful life (group depreciation method) (CICA 3061.31).

7.2 International Financial Reporting Standards

Based on standards issued as of: April 30, 2009

IFRS requirements are largely the same as Canadian GAAP requirements, with the following exceptions:

(a) IFRS specifically requires that depreciation of assets, including spare parts, commences when the asset is available for use rather than put in use, "*Depreciation of an asset begins when it is available for use, ie when it is in the location and condition necessary for it to be capable of operating in the manner intended by management.*" (IAS 16.55). Once an asset is determined to be available for use, capitalization of costs ceases (see also 4.3(c) above), the asset is added to plant, and depreciation commences;

(b) Reviews of depreciation methods and estimates are to be conducted at each financial year end, at a minimum (IAS 16.61);

(c) IFRS does indicate that where a significant part of an item of property, plant and equipment may have a useful life and a depreciation method that are the same as the useful life and the depreciation method of another significant part of that same item, such parts may be grouped in determining the depreciation charge (IAS 16.45). However, common group accounting practices employed by utilities will need to be reviewed to determine if they comply with IFRS.

The major differences in IFRS are that accounting for components is more vigorously followed than under Canadian GAAP, and that non-physical components of assets are also recognized.

(a) To the extent asset classes include components with different lives that would materially impact depreciation, these components must be separately depreciated (IAS 16.43). This requirement will require utilities to analyze each asset class and determine if further componentization is required, and may lead to additional asset classes that do not currently exist;

(b) The recognition of both physical and non-physical components means that costs of major overhauls (IAS 16.13) or inspections (IAS 16.14) embodied in a capital asset may need to be split out and depreciated over a shorter period of life than the actual physical asset. Under Canadian GAAP, these costs would have been expensed as incurred.

8.0 Income Taxes (updated 30 April 2009)

8.1 Canadian GAAP

Based on standards issued as of: April 30, 2009

Currently, utilities in British Columbia that are taxable use the taxes payable (flow-through) method to calculate income tax for regulatory purposes, under which income tax expense is recognized only for taxes that are currently payable to Federal and Provincial governments. In addition, many utilities treat their deferral accounts in their regulatory records on a net-of-tax basis, to allow for differences in the timing of income taxes payable or receivable in rate-setting.

Although the taxes payable method is used for regulatory purposes, Canadian GAAP requires taxes to be recorded using the liability method, which includes the recognition of future income tax expense (CICA 3465.102). To reconcile the differences between the liability method and the taxes payable method, there is a second step permitted under Canadian GAAP. This second step requires the utility to assess whether future income taxes may be expected to be recovered from future customers, and where this is true, to recognize an asset for that expected future revenue (CICA 3465.103).

8.2 International Financial Reporting Standards

Based on standards issued as of: April 30, 2009
Exposure Draft on Income Taxes issued: March 2009
Income Taxes final amendments expected: During 2010

Although IFRS is largely consistent with Canadian GAAP, the second step of recording a regulated future income tax asset or liability is not permitted in the IFRS section on income taxes (IAS 12.15). However, depending on the outcome of the proposed Exposure Draft on Rate-regulated Operations, to the extent this resulting asset or liability meets the recognition criteria under the new standard, the current treatment may continue.

As indicated in the table in Section 1.3, the IFRS standard on Income Taxes is expected to be revised in the next two years.

9.0 Pension and Employee Future Benefit Costs (updated 30 April 2009)

There are a number of differences that will result from adopting IFRS for defined benefit plans. A number of components that make up the cost of defined benefit plans, described under Sections 9.2 to 9.4 below, may be recognized on a different basis than under Canadian GAAP. As indicated in Table 1 in Section 1.3, the standard on Pension and Employee Future Benefit Costs is expected to be revised in the next two years.

9.1 Initial Adoption of IFRS

Based on standards issued as of: April 30, 2009

On transition, utilities may choose to recalculate historical amounts following International Financial Reporting Standards, or they may make a one-time choice to recognize all cumulative actuarial gains and losses not previously recognized in the financial statements as part of the pension asset or liability, with an offsetting entry to retained earnings (IFRS 1 D10).

Table 5. On Transition Pension and Employee Future Benefit Costs: Alternatives and Implications

	Alternative	Implications for Utilities
1	Restatement of historical amounts under IFRS	Significant time and effort required to identify and segregate the non-compliant historical costs
2		Information may not be available for accurate restatement
3		Transition differences to be addressed
4	Recognize cumulative gains and losses as a one-time entry	Transitional retained earnings difference to be addressed

9.2 Actuarial Gains and Losses

9.2.1 Canadian GAAP

Based on standards issued as of: April 30, 2009

Currently, utilities have a choice in recording actuarial gains and losses. They can be recorded in income immediately (CICA 3461.087), or amortized to income using the corridor method whereby gains and losses are recorded in income on a systematic basis with a minimum amount being amortized in any one year (CICA 3461.088).

9.2.2 International Financial Reporting Standards

Based on standards issued as of: April 30, 2009
Exposure Draft Post-employment Benefits expected: Q3 2009
Post-employment Benefits final amendments expected: During 2011

Under IFRS, utilities will have an additional choice in recording actuarial gains and losses. They may be recorded:

(a) In income immediately (IAS 19.95) or on an accelerated basis (IAS 19.93);

(b) Amortized to income using the corridor method (IAS 19.92);

(c) In equity immediately (additional choice under IFRS) (IAS 19.93A).

A proposed change to the pension and future benefit cost standard may eliminate the option of using the corridor method. Transitional impacts resulting in increased volatility in income or equity will need to be addressed. See transition rules in section 9.1.

Table 6. Actual Gains or Losses: Alternatives and Implications

	Alternative	Implications for Utilities
1	Income (immediate or accelerated)	Increased volatility in income
2	Corridor Method	Impacts of gains and losses are smoothed into income
3		May not be available in future
4	Equity	Increased volatility in equity

9.3 Past Service Costs

9.3.1 Canadian GAAP

Based on standards issued as of: April 30, 2009

Canadian GAAP allows past service costs to be recognized over the remaining service life of the employee group (CICA 3461.079).

9.3.2 International Financial Reporting Standards

Based on standards issued as of: April 30, 2009
Exposure Draft Post-employment Benefits expected: Q3 2009
Post-employment Benefits final amendments expected: During 2011

Under IFRS, past service costs must be amortized over the vesting period (when the employee's right to receive the benefit is not conditional on continued employment) (IAS 19.96). In the majority of cases, past service costs would be already vested and would therefore be recognized immediately in income.

9.4 Return on Plan Assets

9.4.1 Canadian GAAP

Based on standards issued as of: April 30, 2009

Canadian GAAP allows the return on plan assets to be estimated at either fair value or a market-related value (value over a period not exceeding five years) (CICA

3461.067). A market-related value dampens the impact of the volatility of actuarial gains and losses on the return on plan assets.

9.4.2 International Financial Reporting Standards

Based on standards issued as of: April 30, 2009
Exposure Draft Post-employment Benefits expected: Q3 2009
Post-employment Benefits final amendments expected: During 2011

Under IFRS, the expected return on plan assets must be estimated using the fair value of assets at the beginning of the period to record investment income which forms part of the pension and employee future benefit expense (IAS 19.106). The use of fair value increases the volatility of actuarial gains and losses on the return on plan assets.

9.5 Measurement Date

9.5.1 Canadian GAAP

Based on standards issued as of: April 30, 2009

For a defined benefit plan, plan assets and the accrued benefit obligation should be measured as of the balance sheet date, except that they may be measured as of a date not more than three months prior to that date provided the entity adopts this practice consistently from year to year (CICA 3461.044).

9.5.2 International Financial Reporting Standards

Based on standards issued as of: April 30, 2009
Exposure Draft Post-employment Benefits expected: Q3 2009
Post-employment Benefits final amendments expected: During 2011

Under IFRS, entities should measure the present value of defined benefit obligations, and the fair value of any plan assets, at the balance sheet date. For entities not measuring defined benefit plans at the balance sheet date, the measurement date would need to be changed which could result in an increase in pension expense or “a charge to equity” in the year of the change (IAS 19.56 & 57 and IAS 19.BC15).

9.6 Summary of Pensions and Employee Future Benefits

These changes to the recognition of pensions and employee future benefits may result in the pension and employee future benefit expenses being more volatile depending on the alternatives chosen for the recognition of actuarial gains and losses.

10.0 Conclusion

This document has summarized those differences between Canadian GAAP and IFRS that have been identified by the Utilities IFRS Working Group as having the most significant impacts on regulatory accounting and rate making. Although this summary may be referred to by the utilities in their various filings and related discussions on IFRS accounting impacts, how the changes will be implemented in the utilities' financial records and rate filings will be discussed in their individual applications to the Commission.

TERASEN GAS INC.

SURREY BRITISH COLUMBIA

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS

RELATED TO GAS PLANT

AT DECEMBER 31, 2007

Gannett Fleming
Valuation and Rate Division

Harrisburg, Pennsylvania **Calgary, Alberta** **Valley Forge, Pennsylvania**

Gannett Fleming

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October 10, 2008

Terasen Gas Inc.
16705 Fraser Highway
Surrey, British Columbia V4N 0E8

Attention: Mr. James Wong
Director, Finance and Planning

Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the gas plant of Terasen Gas Inc. at December 31, 2007. The depreciation study has developed depreciation rates for the Mainland, Vancouver Island, and Whistler systems. Our report presents a description of the methods used in the estimation of depreciation, the statistical analyses of service life and net salvage, and the summary and detailed tabulations of annual and accrued depreciation.

We gratefully acknowledge the assistance of Terasen Gas Inc. personnel in the completion of the study.

Respectfully submitted,

GANNETT FLEMING, INC.

LARRY E. KENNEDY
Director, Canadian Services
Valuation and Rate Division

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CONTENTS

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PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

PART III. RESULTS OF STUDY

PART IV. SERVICE LIFE STATISTICS

PART V. DETAILED DEPRECIATION CALCULATIONS

PART I. INTRODUCTION

TERASEN GAS INC.

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO GAS PLANT
AT DECEMBER 31, 2007

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study conducted by Gannett Fleming, Inc. ("Gannett Fleming") for Terasen Gas Inc. (Terasen) to determine the annual depreciation accrual rates and amounts for book and ratemaking purposes applicable to the original cost of gas plant at December 31, 2007. Separate annual accrual rates have been developed for the provision applicable to the average service life and net salvage components of depreciation expense for each of the Terasen Gas Inc., Terasen Gas Vancouver Island, and Terasen Gas Whistler systems.

The depreciation accrual rates presented herein are based on generally-accepted methods and procedures for calculating depreciation. The service life estimates were based on analyses incorporating data through December 31, 2007, a review of Company practices and outlook as they relate to plant operation and retirement, and the service life and net salvage estimates for other gas transmission and distribution companies.

Part I, Introduction, of this report, contains statements with respect to the scope and plan of the report and the basis of the study. Part II, Methods Used in the Estimation of Depreciation, presents the methods used in the estimation of average service lives, survivor curves and net salvage, and in the calculation of depreciation. Part III, Results of Study, presents a summary of annual and accrued depreciation. Part IV, Service Life

Statistics presents the statistical analyses of service life. Part V, Detailed Depreciation Calculations presents the detailed tabulations of annual and accrued depreciation.

BASIS OF THE STUDY

Depreciation. The annual and accrued depreciation were calculated by the straight line method using the average service life procedure and applied on a remaining life basis. The calculations of composite remaining life and annual depreciation accrual amounts were based on attained ages and estimated service life and net salvage characteristics for each depreciable group of assets.

Service Life and Net Salvage Estimates. The method of estimating service lives consisted of compiling the service life history of the plant accounts and subaccounts, reducing this history to trends through the use of Retirement Rate Method of analysis as further described in Part III of this report, and then applying judgment to make a final estimate of average service life. The results of the statistical analysis resulted in the forecasting of the trend of survivors for each depreciable group on the basis of interpretations of past trends and consideration of Company plans for the future. The combination of historical trend and the estimated future trend yielded a complete pattern of life characteristics from which the average service life was derived.

The service life estimates used in the depreciation calculations incorporated historical data compiled from the property records of the Company. Such data included plant additions, retirements, transfers and other activity from 1958 through 2007. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirement were obtained through discussions with operating and management personnel, and through a tour of company facilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for gas plant. Iowa type survivor curves were used to depict the estimated survivor curves. The estimates of net salvage were based on judgment which incorporated analyses of available historical data, a review of policies and outlook with management, a general knowledge of the gas utility industry, and comparison of the net salvage estimates from studies of other gas utilities. The estimates of net salvage are expressed as the average net percent of the investment to be incurred or recovered upon its retirement. In order to comply with announcements from the Canadian Accounting Standards Board relating to the implementation of the International Financial Reporting Standards ("IFRS"), Terasen has asked Gannett Fleming to develop separate annual accrual and accumulated depreciation calculations related to the requirements for net salvage. A summary of the calculations relating specifically to the net salvage requirement is presented in the Results section of this report.

RECOMMENDATIONS

The calculated annual depreciation accrual rates set forth herein apply specifically to gas plant as of December 31, 2007. Continued surveillance and periodic revisions are required to maintain use of appropriate depreciation rates. The survivor curves, amortization periods and net salvage percents determined in this study should be the basis for periodic recalculations. Complete depreciation studies which re-evaluate these parameters should be performed every three to five years.

PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

DEPRECIATION

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy and obsolescence.

Service Value, in public utility regulation, means the difference between original cost and the net salvage value of gas plant.[1] Net Salvage Value is considered to be the amount received for property retired less any expenses incurred in connection with the sale of the asset, or in preparing the asset for sale.[2] As such, the depreciation study completed by Gannett Fleming and as presented in this report has developed annual accrual rates applicable to both the recovery of the original costs and separately for the net salvage component of the utility assets in service as at December 31, 2007.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal

[1] Federal Energy Regulatory Commission, Natural Gas Act, Part 201-Uniform System of Accounts Prescribed for Natural Gas Companies subject to the Provisions of the Natural Gas Act, Page 516-Definitions.
[2] Ibid, footnote 1

amount of cost to each year of service life. This method is known as the straight line method of depreciation.

The calculation of annual depreciation based on the straight line method requires the estimation of average life and salvage and the selection of group depreciation procedures. These subjects are discussed in the sections that follow.

ESTIMATION OF SURVIVOR CURVES

Average Service Life. The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages. A discussion of the general concept of survivor curves is presented. Also, the Iowa type survivor curves are reviewed.

Survivor Curves. The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval and is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

Iowa Type Curves. The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

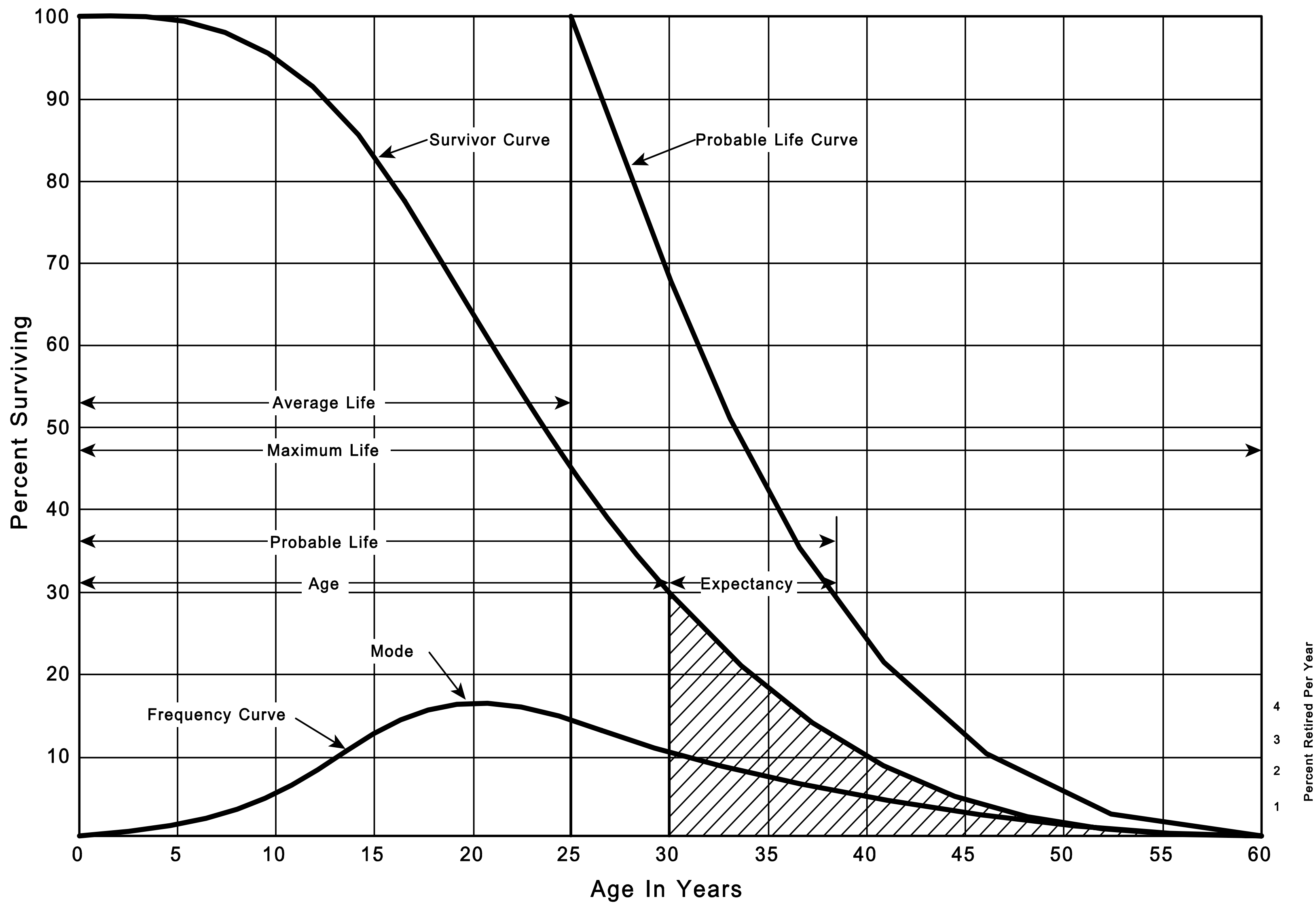

Figure 1. A Typical Survivor Curve and Derived Curves

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.[3] These type curves have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[4] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[5] presenting his development of the fourth family consisting of the four O type survivor curves.

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[3] Winfrey, Robley. Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

[4] Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[5] Couch, Frank V. B., Jr. "Classification of Type O Retirement Characteristics of Industrial Property." Unpublished M.S. thesis (Engineering Valuation). Library, Iowa State College, Ames, Iowa. 1957.

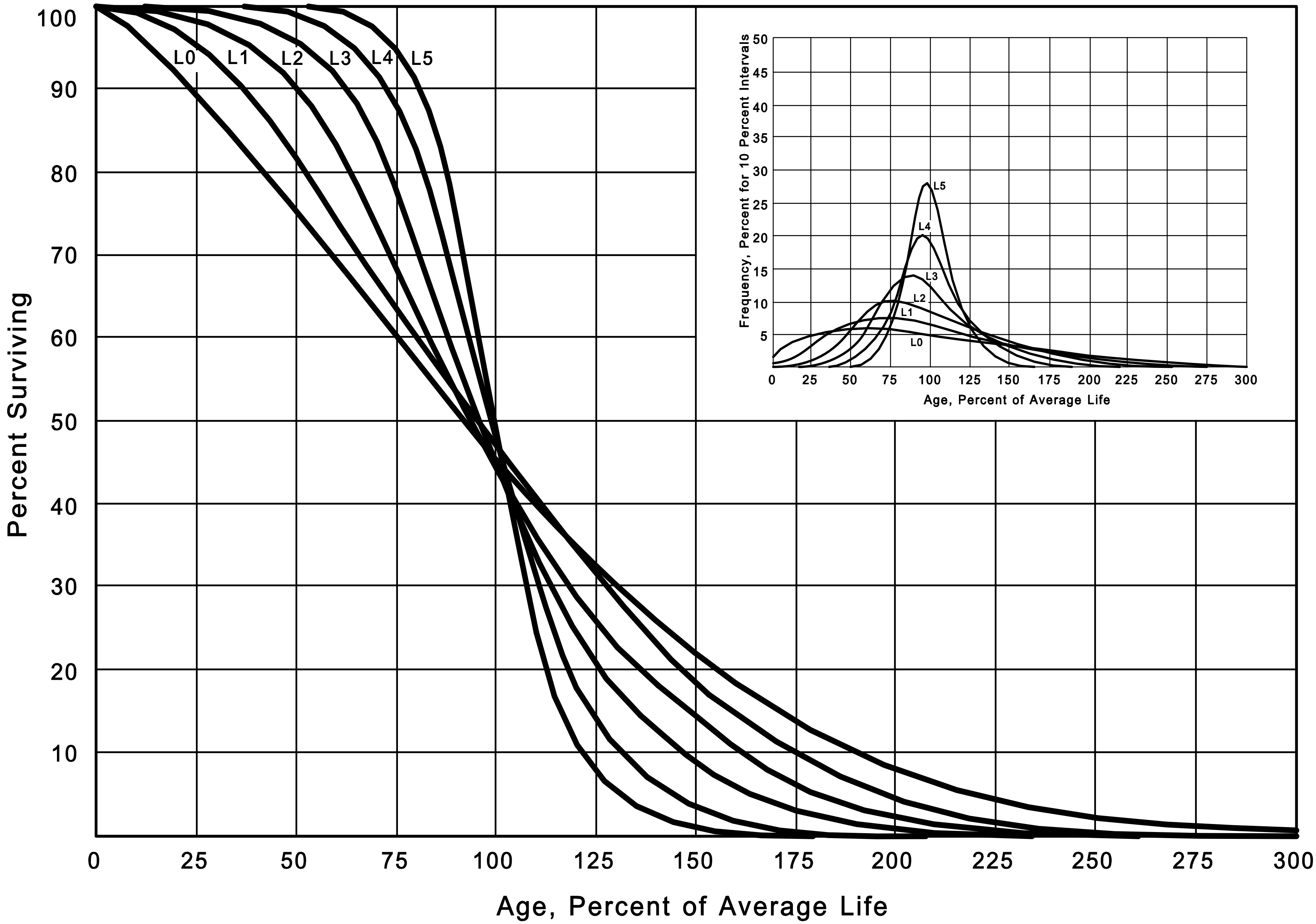

Figure 2. Left Modal or "L" Iowa Type Survivor Curves

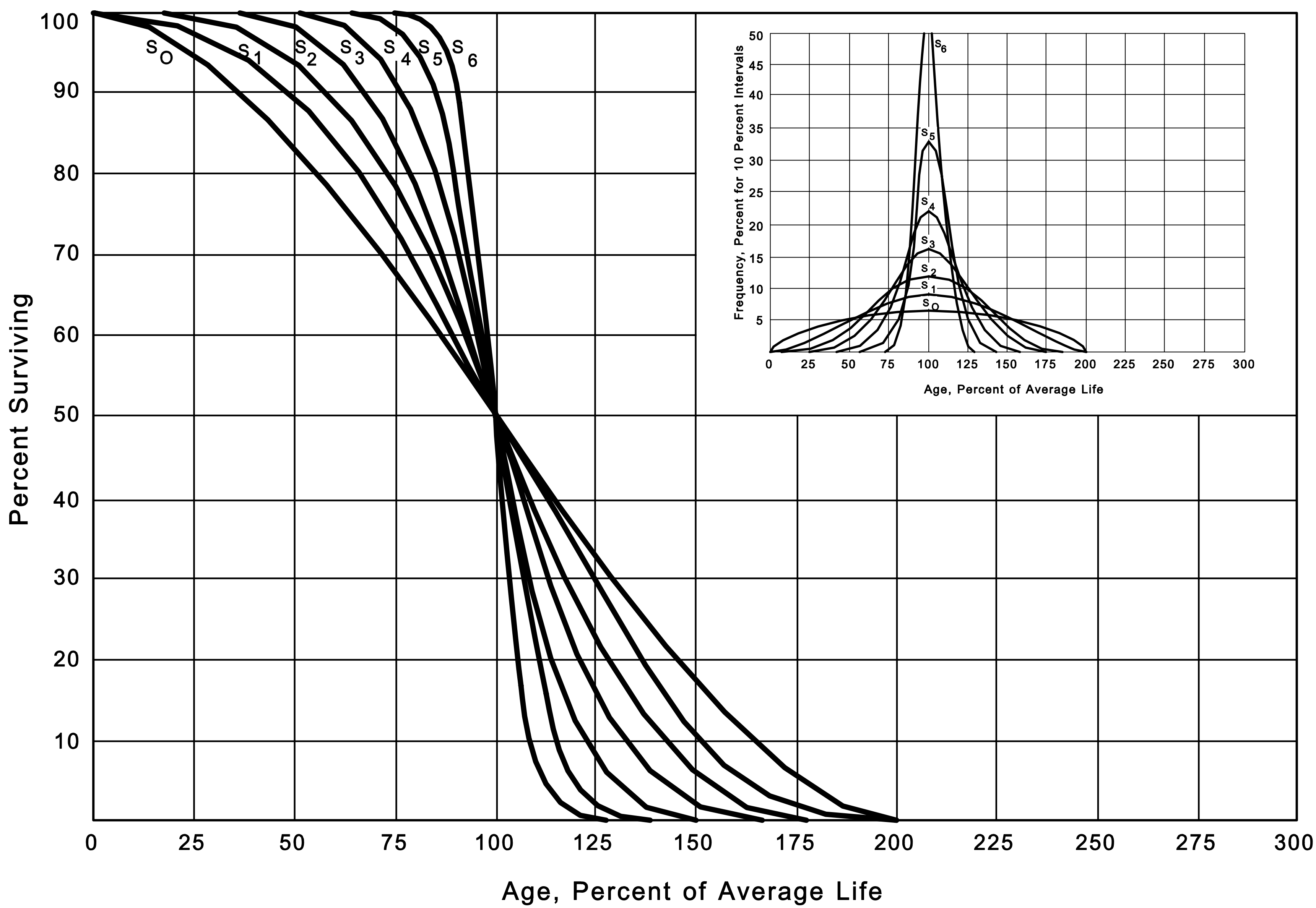

Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

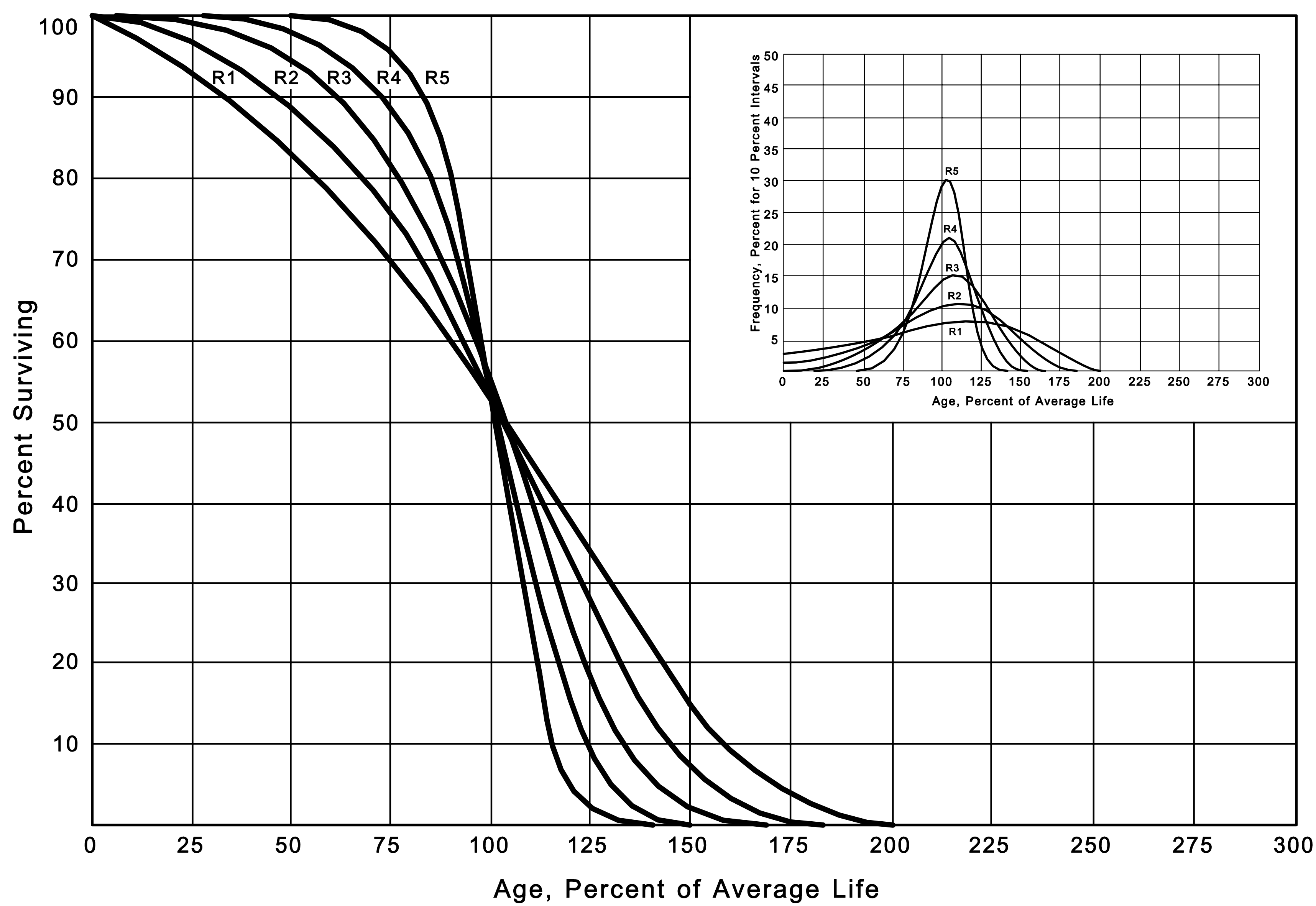

Figure 4. Right Modal or "R" Iowa Type Survivor Curves

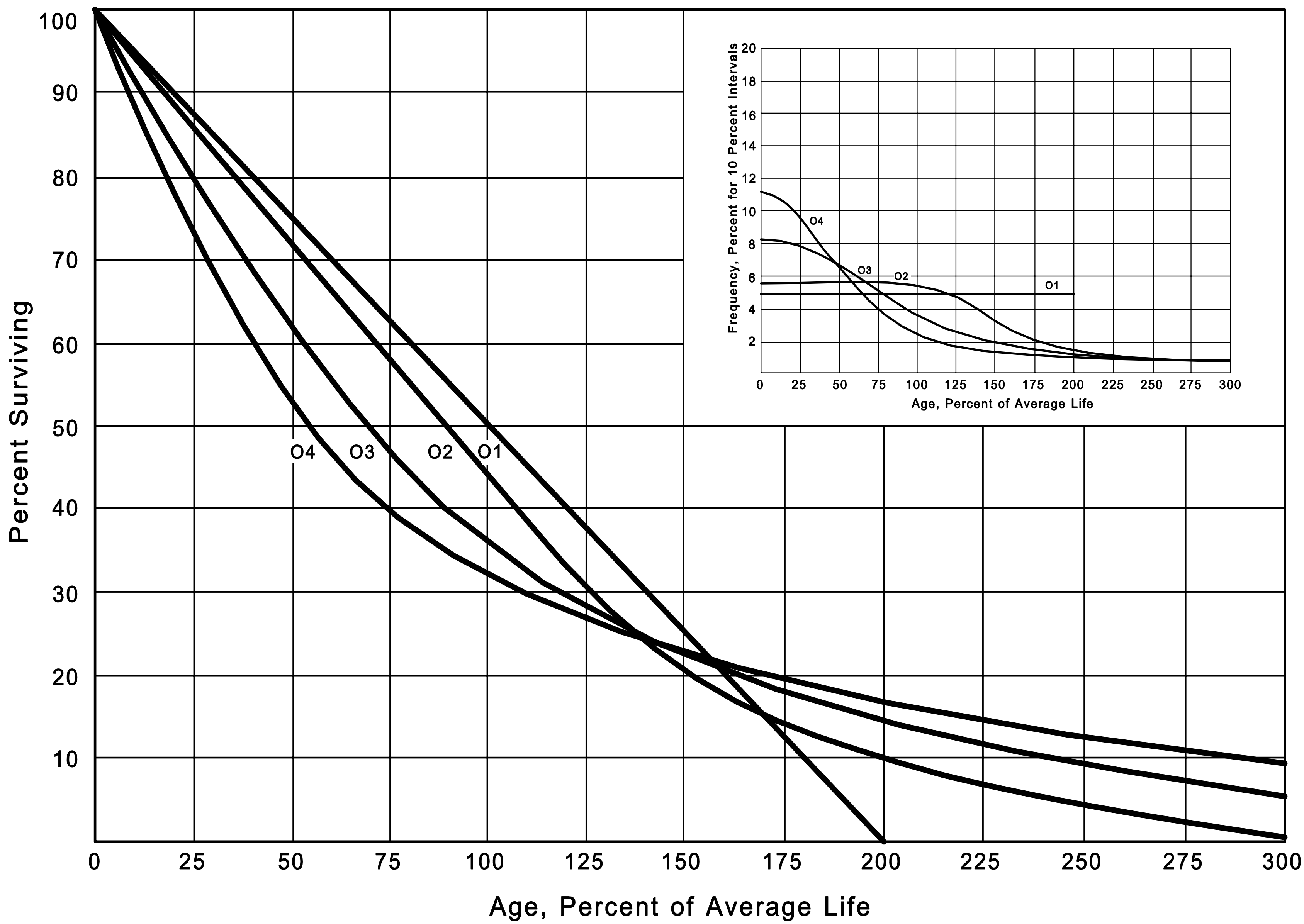

Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

Retirement Rate Method of Analysis. The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available or for which aged accounting experience is developed by statistically aging unaged amounts and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"[6] "Engineering Valuation and Depreciation,"[7] and "Depreciation Systems."[8]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginnings of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

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[6]Winfrey, Robley, Supra Note 3.

[7]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note

[8]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

Schedules of Annual Transactions in Plant Records. The property group used to illustrate the retirement rate method is observed for the experience band 1998-2007 during which there were placements during the years 1993-2007. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Tables 1 and 2 on the following pages. In Table 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 1993 were retired in 1998. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Table 1 immediately above the stairstep line drawn on the table beginning with the 1998 retirements of 1993 installations and ending with the 2007 retirements of the 2002 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

TABLE 1. RETIREMENTS FOR EACH YEAR 1998-2007
SUMMARIZED BY AGE INTERVAL

Experience Band 1998-2007

Placement Band 1993-2007

Year Placed (1)	1998 (2)	1999 (3)	2000 (4)	2001 (5)	2002 (6)	2003 (7)	2004 (8)	2005 (9)	2006 (10)	2007 (11)	Total During Age Interval (12)	Age Interval (13)
	Retirements, Thousands of Dollars During Year											
1993	10	11	12	13	14	16	23	24	25	26	26	13½-14½
1994	11	12	13	15	16	18	20	21	22	19	44	12½-13½
1995	11	12	13	14	16	17	19	21	22	18	64	11½-12½
1996	8	9	10	11	11	13	14	15	16	17	83	10½-11½
1997	9	10	11	12	13	14	16	17	19	20	93	9½-10½
1998	4	9	10	11	12	13	14	15	16	20	105	8½-9½
1999		5	11	12	13	14	15	16	18	20	113	7½-8½
2000			6	12	13	15	16	17	19	19	124	6½-7½
2001				6	13	15	16	17	19	19	131	5½-6½
2002					7	14	16	17	19	20	143	4½-5½
2003						8	18	20	22	23	146	3½-4½
2004							9	20	22	25	150	2½-3½
2005								11	23	25	151	1½-2½
2006									11	24	153	½-1½
2007	—	—	—	—	—	—	—	—	—	13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

TABLE 2. OTHER TRANSACTIONS FOR EACH YEAR 1998-2007
SUMMARIZED BY AGE INTERVAL

Experience Band 1998-2007

Placement Band 1993 -2007

Year Placed (1)	Acquisitions, Transfers and Sales, Thousands of Dollars During Year 1998 (2)	1999 (3)	2000 (4)	2001 (5)	2002 (6)	2003 (7)	2004 (8)	2005 (9)	2006 (10)	2007 (11)	Total During Age Interval (12)	Age Interval (13)
1993	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
1994	-	-	-	-	-	-	-	-	-	-	-	12½-13½
1995	-	-	-	-	-	-	-	-	-	-	-	11½-12½
1996	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
1997	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
1998		-	-	-	-	-	-	-	-	-	(5)	8½-9½
1999		-	-	-	-	-	-	-	-	-	6	7½-8½
2000			-	-	-	-	-	-	-	-	-	6½-7½
2001				-	-	-	-	(12)[b]	-	-	-	5½-6½
2002					-	-	-	-	22[a]	-	-	4½-5½
2003						-	-	(19)[b]	-	-	10	3½-4½
2004							-	-	-	-	-	2½-3½
2005								-	-	(102)[c]	(121)	1½-2½
2006									-	-	-	½-1½
2007											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses denote Credit amount.

In Table 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement. The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Table 3 on page II-16 .

The surviving plant at the beginning of each year from 1998 through 2007 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Table 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net entries shown on Tables 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2003 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

TABLE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 1998-2007
SUMMARIZED BY AGE INTERVAL

Experience Band 1998-2007

Placement Band 1993-2007

	Exposures, Thousands of Dollars — Annual Survivors at the Beginning of the Year											
Year Placed (1)	1998 (2)	1999 (3)	2000 (4)	2001 (5)	2002 (6)	2003 (7)	2004 (8)	2005 (9)	2006 (10)	2007 (11)	Total at Beginning of Age Interval (12)	Age Interval (13)
1993	255	245	234	222	209	195	239	216	192	167	167	13½-14½
1994	279	268	256	243	228	212	194	174	153	131	323	12½-13½
1995	307	296	284	271	257	241	224	205	184	162	531	11½-12½
1996	338	330	321	311	300	289	276	262	242	226	823	10½-11½
1997	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
1998	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
1999		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2000			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2001				580[a]	574	561	546	530	501	482	3,057	5½-6½
2002					660[a]	653	639	623	628	609	3,789	4½-5½
2003						750[a]	742	724	685	663	4,332	3½-4½
2004							850[a]	841	821	799	4,955	2½-3½
2005								960[a]	949	926	5,719	1½-2½
2006									1,080[a]	1,069	6,579	½-1½
2007										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a] Additions during the year.

For the entire experience band 1998-2007, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Table 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

<u>Original Life Table</u>. The original life table, illustrated in Table 4 on page II-18, is developed from the totals shown on the schedules of retirements and exposures, Tables 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

TABLE 4. ORIGINAL LIFE TABLE

CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 1998-2007 Placement Band 1993-2007

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval (1)	Exposures at Beginning of Age Interval (2)	Retirements During Age Interval (3)	Retirement Ratio (4)	Survivor Ratio (5)	Percent Surviving at Beginning of Age Interval (6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
14.5					35.66
Total	44,780	1,606			

Column 2 from Table 3, Column 12, Plant Exposed to Retirement.
Column 3 from Table 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 of the Preceding Age Interval.

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Tables 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

The original survivor curve is plotted from the original life table (column 6, Table 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

<u>Field Trip</u>. In order to be familiar with the Company and observe a representative portion of the plant, a field trip was conducted. As described in the next section of this report, a number of operational interviews were conducted before and after the field trips. In this manner, the knowledge gained during the operational interviews could be enhanced through the physical inspection of plant. Additionally, a number of questions that arose during the field trips were discussed during operational discussions following the site inspections. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements were obtained during the field trip. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

The following is a list of the locations visited during the field trip.

- Surrey Operations Center
- Huntingdon Metering Station
- Langley Compressor Station
- Coquitlam Metering Station
- Tilbury LNG Plant

Operational Interviews. Interviews and discussions were held with a number of operational and engineering groups. The interviews and discussions assisted Gannett Fleming in the understanding of the historic forces of retirement that have resulted in the statically developed average service life indications and on the anticipated future forces of retirement. Based on these discussions, Gannett Fleming is better able to determine if the results of the retirement rate analysis should be adjusted to better reflect the future forces of retirement, or changes in technology. Additionally, operational interviews provide information regarding the reuse practices and policies and cost of retirement information. Interviews with budgeting departments provided insight into upcoming capital programs which may include significant retirement of assets.

The following groups were interviewed by Gannett Fleming during the Depreciation Study:

- Vancouver Island System Operations
- Fleet Management
- Metering
- Transmission
- Compression
- Capital Expenditure Budgeting
- Distribution Stations
- Inventory

The information gained from these interviews was used in combination with the retirement rate study, comparisons to peers and the experience of Gannett Fleming in the final determination of average service life estimates and net salvage percentages.

Survivor Curve Judgments. Each retirement rate analysis resulted in a life table which, when plotted, formed an original survivor curve. Each original survivor curve, as plotted from the life table, represents the average survivor pattern experienced by several vintage groups during the experience band studied. Inasmuch as this survivor pattern does not necessarily describe the life characteristics, interpretation of the original survivor curves is required to use them as valid considerations in service life estimation. Iowa type curves were used in these interpretations. The survivor curve estimates were based on judgment which considered a number of factors as discussed above. The primary factors were the statistical analysis of data, current policies and outlook as determined during conversations with management and the field trip, and survivor curve estimates from previous studies of this Company and other gas distribution companies. The specific factors for the largest accounts follow.

Account 475 – Distribution Mains, is the largest account studied and represents 25% of Terasen's depreciable plant. The retirements, additions and other plant transactions for the period 1958 through 2007 were analyzed by the retirement rate method. The original and smooth survivor curves are plotted on page lV-47. Typical service lives for distribution mains range from 50 to 65 years.

In previous studies Gannett Fleming recommended the Iowa 60-R2.5. Since the last study, this account has continued to incur retirements at a consistent rate which provide for a reliable statistical indication of average service life characteristics. To date, this account has experienced over $27 million of retirement actively. Discussions with operating and engineering staff have not indicated any specific reasons to believe that the future retirement trends in this account will be significantly different than either historic pattern. Furthermore, operations staff have indicated that it would be expected that the life of the

Terasen distribution mains would be in the range of other industry peers. Typical service lives for distribution mains range from 50 to 65 years.

The retirement rate analysis indicates a significant rate of retirement activity as plant reaches 50 years of age, with large retirement rates through to age 75. In order to better fit to this retirement pattern, Gannett Fleming has recommended the Iowa 60-R3 survivor curve to better reflect the trend towards increased retirement rates beyond age 50 as compared to the previous estimate of the 60-R2.5. This minor increase in the mode of the Iowa curve provides a reasonable interpretation of the original survivor curve, and falls within the range of typical service lives for this account and is therefore recommend for this account.

Account 465, Transmission Mains, represents approximately 23% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1957 through 2007 were studied. The original survivor curve as plotted on page IV-20 indicates only a modest level of retirements through age 45. Typical service lives for transmission mains range from 50 to 70 years. The previously approved estimate for this account was the Iowa 65-R3 based primarily on industry trends.

The Retirement Rate Analysis as presented at page IV-21 of this report and discussions with the operations and engineering staff have indicted that to date the pipe has experienced only a limited level of retirement activity. However, the retirement activity to date of over $9 Million of originally installed cost, has provided some data upon which a life analysis can be made, particularly when combined with the experience of the operations staff. Operations staff has indicated that the original 12-inch system installed in 1957 is not cathodically protected. However the cathodic protection was started in the late 1960’s with the installation of the 10-inch lines. Terasen does inspect the transmission lines using inspection pigs through an on-going inspection program. Recent inspections have indicated some corrosion in the 10-inch line. In previous studies Gannett Fleming recommended an Iowa 65-R3 curve. However, the average service life in this study has been shortened to an Iowa 60-R3 to better fit the historic retirement activity, and to recognize the anticipated increased level of retirements in future years due to the potential of corrosion in the 10-inch line. The Iowa 60-R3 survivor curve, selected in this study to represent the life characteristics for this account, is within the typical range of lives used for transmission mains in the industry, and conforms to the expectations of management.

Account 473, Distribution Services, represents 18% of Terasen's depreciable plant. The retirements, additions and other plant transactions for the period 1959 through 2007 were analyzed by the retirement rate method. The original and smooth survivor curves are plotted on page IV-40.

In previous studies Gannett Fleming recommended the Iowa 55-R1. Since the last study, this account has continued to incur retirements at a consistent rate, which provides for a reliable statistical indication of average service life characteristics. To date, this account has experienced over $44 million of retirement activity. Discussions with operating and engineering staff have not indicated any specific reasons to believe that the future retirement trends in this account will be significantly different than historic patterns. Furthermore, operations staff have indicated that it would be expected that the life of the Terasen distribution services would be in the range of other industry peers. Typical service lives for distribution services range from 40 to 60 years.

The retirement rate analysis indicates a significant rate of retirement activity as plant reaches 45 years of age, with large retirement rates through to age 70. In order to better fit to this retirement pattern, Gannett Fleming has recommended the Iowa 55-R2.5 survivor curve to better reflect the trend toward increased retirement rates beyond age 40, as compared to the previous estimate of the Iowa 55-R1. This minor increase in the mode of the Iowa curve provides a reasonable interpretation of the original survivor curve, and falls within the range of typical service lives for this account and is, therefore recommended for this account.

Account 478.1, Meters, represents 6% of Terasen's depreciable plant. The retirements, additions and other plant transactions for the period 1963 through 2007 were analyzed by the retirement rate method. The original and smooth survivor curves are plotted on page IV-60. Typical service lives for gas distribution services range from 15 to 30 years. In recent years, the gas distribution industry has been moving toward increased used of digital metering and Automated Meter Reading (AMR) technology. The impact of the changed technology on the average service life of meters has not yet been witnessed.

Previous Gannett Fleming studies have recommended a 25-R2-Iowa curve to represent the retirement characteristics for this account. During the period since the last study, Terasen Gas has entered into a program to replace the older electro-mechanical meters with newer technology digital metering equipment. Furthermore, Terasen is testing AMR technology through a residential test program. The impact of the new metering technology and potential for the implementation of AMR is unknown, but may cause a future retirement program to replace a significant portion of the investment in this account. It is anticipated that the retirement activity caused by the program nature of the conversion will result in an increased number of retirements at a younger age. However, until these programs are more certain and the results of the AMR projects are known, Gannett Fleming does not recommend large changes in the average service life of this account due to this introduction of new technology in this account.

Effective January 1, 2007, Terasen made a significant policy change regarding the manner in which meter related costs are capitalized. The revised policy has two key components, as follows:

- Meter repair and inspection costs incurred in the meter shop will no longer be capitalized, and the costs will be considered as operating costs and
- Field costs associated with residential meter exchanges will now be capitalized, where the old meter is expected to be retired.

The above changes in capitalization policy will not have any material impact with regard to average service life estimates. The policy to charge the repair of meters in the meter shop to operating cost could have a slight lengthening impact on average service life, as any potential retirement of a portion of the asset will no longer occur. However small retirements for replaced parts on the meter have not historically been recorded and, therefore, no charge in average service life is expected due to this change.

The retirement rate analysis for this account, as presented at page IV-61, indicates retirement activity throughout the accounts life constant with an Iowa 25-R2 shape. While this account is experiencing significant change in both the capitalization policies and in the technology associated with the assets within this account, the impacts of these changes are not known at this time. Therefore, absent any empirical data to support a shortening of the average service life estimate, the 25-R2 has been selected for this account. This account will be closely monitored over the next few years to determine if a shortening of the average service life estimate becomes necessary.

<u>Account 466, Compression Equipment</u>, represents less than 4% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1970 through 2007 were analyzed by the retirement rate method. The original survivor curve as

plotted on page IV-23 indicates only a modest level of historical retirements through age 15, and a significantly faster rate of retirement from ages 16 through 21. Plant surviving past age 21 appears to be at a much slower pace.

In previous depreciation studies, Gannett Fleming has recommended a 30-R2.5 Iowa curve. Typical service lives for compression equipment range from 25 to 35 years. The compression units, utilized by Terasen are Solar units which have proven to be reliable both at Terasen and within the industry as a whole. As such, it is expected that these units would perform at the longer end of the range of average service lives. However, the high rate of retirement ratios at approximately age 20 need to be recognized. Gannett Fleming recommends a slight lengthening of the average service life to 33 years to deal with the company and industry experience with the compression units in use, and an increase in the mode of the Iowa curve from a Iowa R2.5 to an Iowa R3 to deal with the period of high retirement ratios. As such, an adjustment to the Iowa 33-R3, selected in this study, provides a reasonable interpretation of the historical data, and is within the range of lives used in the industry and anticipated by management.

Account 477.1, Measuring and Regulators, represents 2% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1962 through 2007 were analyzed by the retirement rate method. The original survivor curve as plotted on page IV-52 indicates only a relatively constant rate of historical retirements through age 35, at which point the amount of plant exposed to retirement becomes minimal. As such, in the analysis of this account, Gannett Fleming has fit to the retirement experience from age 0 through to age 35. Over this period, most significant retirements occur from age 0 through age 17.

Gannett Fleming has previously recommended the Iowa 29-R2 curve for this account. However, given the high rate of retirements beginning at age 0 and the minimal amount of plant remaining in service after age 35, Gannett Fleming is recommending a reduction to this average service life. A reduction in the average service life estimate to the Iowa 25-R2, selected in this study, provides a reasonable interpretation of the historical data, and is within the range of lives which used in the industry which range from 20 to 30 years.

The survivor curves for the remaining accounts were based on similar considerations of historical analysis, management outlook and estimates of this company and other gas distribution companies.

ESTIMATION OF NET SALVAGE

Appropriate depreciation policies should provide for the recovery of the service value of assets in regulatory service over the period of time for which the assets being depreciated are forecast to be in service. This concept has been held by numerous regulatory jurisdictions throughout North America for many years. The concept of service value to include both the original costs of the asset and the net salvage costs incurred at the time of retirement of the asset is also widely held.[9] As such, in the completion of the depreciation study for Terasen Gas, Gannett Fleming has developed appropriate net salvage rates, which when applied to the original cost of plant in service, will result in the provision of funds estimated to be required at the time of retirement.

[9] For example as identified by the FERC as noted in footnote 2 to this report and in the General Instructions to the Canadian Gas Association Uniform Classification of Accounts for Natural Gas Utilities under the Jurisdiction of the Public Utilities Board of the Province of Alberta, page 8

The recovery of the estimated costs of retirement (net of any potential salvage proceeds realized from the sale of assets to third parties or from reuse within the utility) over the period of time that the asset is providing utility service provides generational equity wherein the toll payers receiving the benefit of an asset in service fund the total cost of the asset, including the eventual costs of retirement of the asset.

Recently, the Canadian Accounting Standards Board has announced that Canadian Generally Accepted Accounting Principles (GAAP) will cease to exist as of 2011. From that date forward, companies will be required to report under International Financial Reporting Standards (“IFRS”). One of the areas of change relate to the depreciation of assets relating to net salvage requirements. In order to comply with these new standards, Terasen Gas has asked that Gannett Fleming prepare separate depreciation accrual rates specifically applicable to the net salvage requirements. As such, Table 1, as presented in the Results section of this report, provides for the recovery of the original cost of assets in service; and Table 2 separately provides for the recovery of the estimated costs of retirement. It is the recent experience of Gannett Fleming that regulated Canadian Utilities are complying with the IFRS in this manner.

The estimates of net salvage recommended in this report were primarily based on judgment which considered a number of factors. The primary factors were knowledge of the company’s plans and operating practices as determined during the field trip and discussions with operating, engineering and budgeting staff, a general knowledge of the natural gas industry, and review of the net salvage estimates of other gas companies. The estimates of net salvage are expressed as the average net percent of the cost of plant.

CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

Group Depreciation Procedures. When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, the average service life and equal life group procedures.

In the average service life procedure, the rate of annual depreciation is based on the average service life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to the average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the equal life group procedure, also known as the unit summation procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life unit. Although the equal life group procedure is superior to the average service life procedure in matching depreciation expense and consumption of service value, the average service life procedure was used in order to conform to past Company practices and for consistency with practices of other companies regulated by the British Columbia Utilities Commission.

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for certain General Plant accounts that represent numerous units of property, but a very small portion of depreciable gas plant in service. The accounts and their amortization periods are as follows:

	Account	Amortization Period Years
401	Franchises and Consents	40
402	Intangible Plant	40
483.1	Computer Hardware	5
483.2	Computer Software	5
483.3	Office Equipment	15
483.4	Office Furniture	20
486	Small Tools/Equipment	20
487.2	NGV Cylinders	15
488.1	Telephone Equipment	15
488.2	Radio Equipment	15

The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the original cost by the period of amortization for the account for those vintages with an age less than the amortization period. In order to develop amortization rates that reflect the period over which the assets render service, the accumulated depreciation accounts have been adjusted for the purposes of this study to remove any amounts other than the accumulated depreciation related to the assets currently in service. As a result, the amortization rate as recommended in this report represent the pure amortization rate without any other accumulated depreciation adjustments.

Use of the amortization method of accounting generally includes the retirement of the investment in these accounts at the expiry of the amortization period. As such, no investment is retired prior to the expiry of the period and all investment is retirement at the end of the period, regardless of when the items are physically removed from service. As part of the review of the general plant accounts for this study, the amortization rates only considered the investment that is within the recommended amortization period.

PART III. RESULTS OF THE STUDY

PART III. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculation of the composition remaining lives and the determination of the annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revision are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage, and for the change of the composition of property in service.

The annual accrual rates and the accrued depreciation were calculated in accordance with the straight line average service life method of depreciation based on estimates which reflect consideration of current historical evidence and expected future conditions. The calculated accrued depreciation represents that portion of the depreciable cost which will not be allocated to future annual expense through depreciation accruals if current forecasts of service life and salvage materialize and are used as a basis for straight line average service life depreciation accounting.

DESCRIPTION OF DEPRECIATION TABULATIONS

A summary of the results of the study, as applied to the original cost of gas plant of Terasen Gas Inc., Terasen Gas Vancouver Island, and Terasen Gas Whistler as at December 31, 2007, is presented in Tables 1 and 2 attached to this report. Table 1 sets forth the original cost, the booked accumulated depreciation amounts, and the required future accruals prior to consideration of the net salvage provision for Terasen Gas Inc., Terasen Gas Vancouver Island, and Terasen Gas Whistler. As such, Table 1 for each system provides for the recovery of the original costs of the assets within each system.

Table 2 presents the calculations related to the recovery of the net salvage requirements for each of the same three systems.

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and operating staff, and consideration of estimates made for other gas companies as discussed in Part II of this report. For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table plotted on the charts is presented starting at page IV-2. The survivor curve estimated for the depreciable groups is shown as a dark smooth curve on the charts. Each smooth curve is denoted by a numerical average service life indication followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of each chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables that are plotted. The experience band indicates the range of years fro which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The tables of the calculated annual and accrued depreciation are presented in account sequence in the section beginning on V-2**.** With the exception of the general plant accounts, the tables are first presented for all of the Terasen Gas Inc. accounts, followed by all of the Terasen Gas Vancouver Island accounts and then for all accounts related to Terasen Gas Whistler. Each table indicates the estimated survivor curve and net salvage percent for the account;and sets forth, for each installation year, the original cost, the calculated annual accrual rate and amount, and the calculated accrued depreciation factor and amount.

As previously indicated the amortization rates for general plant accounts, as developed in this report are based on adjusted gross plant in service and accumulated depreciation balances. As these amortization rates for the general plant accounts are developed as a pure rate the aged plant surviving balances for only the investment within the amortization period has been considered. Therefore the general plant accounts are not included in the detailed depreciation calculation pages beginning at page V-2 of this report.

TERASEN GAS INC.

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2007
DEPRECIATION RELATED TO LIFE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2007	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	Intangible Plant								
401.0	Franchises and Consents	40-SQ	0	99,236	47,482	51,754	19,611	19.76	2.6
402.0	Intangible Plant	40-SQ	0	772,555	205,894	566,661	16,526	2.14	34.3
402.1	Plant Acquisitions and Adjustments	40-SQ	0	62,457	25,521	36,936	14,774	23.66	2.5
	Total Intangible Plant			**934,248**	**278,897**	**655,351**	**50,912**	**5.45**	
	Manufacturing Plant								
432.0	Manufacturing Gas Structures	40-SQ	0	450,708	85,863	364,845	14,783	3.28	24.7
433.0	Manufacturing Gas Equipment	20-SQ	0	145,939	42,710	103,229	9,196	6.30	11.2
434.0	Manufacturing Gas Holders	40-SQ	0	357,586	158,645	198,941	13,939	3.90	14.3
436.0	Manufacturing Gas Compressor Equipment	25-SQ	0	53,309	20,072	33,237	2,642	4.96	12.6
437.0	Manufacturing Gas Measuring/Regulating Equipment	20-SQ	0	309,447	133,516	175,931	60,354	19.50	2.9
	Total Manufacturing Plant			**1,316,989**	**440,806**	**876,183**	**100,914**	**7.66**	
	LNG Plant								
442.0	LNG Gas - Structures	25-R3	-10	4,779,018	1,702,128	3,076,890	174,645	3.65	17.6
443.0	LNG Gas - Equipment	40-R3	-20	16,495,801	6,943,654	9,552,147	360,024	2.18	26.5
449.0	LNG Gas - Other Equipment	35-R3	-10	18,936,395	7,463,537	11,472,858	635,510	3.36	18.1
	Total LNG Plant			**40,211,214**	**16,109,319**	**24,101,895**	**1,170,178**	**2.91**	
	Transmission Plant								
462.0	TP - Compressor Structures	30-R4	-5	14,587,984	4,178,048	10,409,936	559,824	3.84	18.6
463.0	TP - Measuring/Regulating Structures	30-R2.5	-5	4,839,702	971,868	3,867,834	206,759	4.27	18.7
464.0	TP - Other Structures	35-R3	-5	5,842,863	956,201	4,886,662	168,227	2.88	29.0
465.0	TP - Transmission Pipeline	60-R3	-10	700,388,612	141,662,619	558,725,993	11,422,619	1.63	48.9
466.0	TP - Compressor Equipment	33-R3	-10	106,301,110	26,281,352	80,019,758	3,380,640	3.18	23.7
467.1	TP - Measuring/Regulating Equipment	25-R2.5	-5	27,913,211	4,286,756	23,626,455	2,005,641	7.19	11.8
467.2	TP - Telementry Equipment	17-R2	0	6,065,331	4,836,167	1,229,164	80,580	1.33	15.3
467.3	TP - Measurement/Regulating Equipment	25-R2.5	-5	38,716	4,753	33,963	1,551	4.01	21.9
468.0	TP - Communications Equipment	15-R2	0	345,886	197,658	148,228	18,393	5.32	8.1
	Total Transmission Plant			**866,323,415**	**183,375,422**	**682,947,993**	**17,844,235**	**2.06**	
	Distribution Plant								
472.0	DS - Structures	28-L1	-5	13,845,551	2,398,305	11,447,246	498,573	3.60	23.0
473.0	DS - Services	55-R2.5	-50	578,026,320	51,399,770	526,626,550	13,004,730	2.25	40.5
473.01	LILO - DS - Services	40-SQ	-50	43,302,554	9,662,455	33,640,099	952,600	2.20	35.3
474.0	DS - Meters/Regulators Installations	30-R2	0	127,327,914	5,285,163	122,042,751	6,636,365	5.21	18.4
474.01	LILO - DS - Meters/Regulators Installations	30-SQ	0	16,070,133	7,123,947	8,946,186	352,434	2.19	25.4
475.0	DS - Mains	60-R3	-20	790,729,371	174,026,268	616,703,103	14,917,469	1.89	41.3
475.01	LILO - DS - Mains	40-SQ	-20	39,743,548	11,665,494	28,078,054	793,861	2.00	35.4
476.0	DS - NGV Fuel Equipment	15-R3	0	570,858	229,823	341,035	142,932	25.04	2.4
477.1	DS - Meters/Regulators Additions	25-R2	0	72,654,480	10,952,419	61,702,061	4,157,541	5.72	14.8
477.2	DS - Telemetry	20-R2.5	0	5,527,676	5,277,715	249,961	13,802	0.25	18.1
477.3	DS - Measuring/Regulating Equipment	15-R2.5	-5	163,151	174,677	(11,526)	-	-	1.0
478.1	DS - Meters	25-R2	0	180,537,629	35,702,962	144,834,667	9,587,890	5.31	15.1
478.11	LILO - DS Meters	25-SQ	0	10,026,726	3,351,178	6,675,548	329,852	3.29	20.2
478.2	DS - Instruments	30-R3	0	10,942,940	2,021,854	8,921,086	440,896	4.03	20.2
	Total Distribution Plant			**1,889,468,851**	**319,272,030**	**1,570,196,821**	**51,828,944**	**2.74**	
	General Plant								
482.1	Structures (Frame)	25-R2	0	5,637,521	1,681,346 *	3,956,175	207,130	3.67	19.1
482.2	Structures(Masonry)	25-R2	0	81,459,403	7,241,295 *	74,218,108	3,563,039	4.37	20.8
483.1	Computer Hardware	5-SQ	0	13,863,764	7,255,376 *	6,608,388	2,772,091	20.00	2.4
483.20	Computer Software (8 Years)	8-SQ	0	71,038,304	42,948,228 *	27,825,480	8,878,583	12.50	3.1
483.21	Computer Software (5 Years)	5-SQ	0	6,787,308	1,111,596 *	5,675,712	1,357,176	20.00	4.2
483.3	Office Furniture and Equipment	15-SQ	0	4,248,230	2,296,043 *	1,952,187	283,336	6.67	6.9
483.4	Furniture	20-SQ	0	20,073,829	10,519,950 *	9,553,879	1,004,614	5.00	9.5
484.0	Vehicles	6-L1	20	695,457	486,610	208,847	53,551	7.70	3.9
485.1	Heavy Work Equipment	15-R2	15	189,165	48,520	140,645	12,558	6.64	11.2
485.2	Heavy Mobile Equipment	15-L2.5	10	312,945	15,682	297,263	26,541	8.48	11.2
486.0	Small Tools/Equipment	20-SQ	0	32,034,924	14,362,213 *	17,672,711	1,600,789	5.00	11.0
487.2	NGV Cylinders	15-SQ	0	24,167	2,705	21,462	1,612	6.67	13.3
487.3	VRA's	10-SQ	0	-	-	-	-	-	0.0
488.1	Telephone Equipment	15-SQ	0	10,450,131	5,124,276 *	5,325,855	696,554	6.67	7.6
488.2	Radio Equipment	15-SQ	0	4,992,872	1,639,789 *	3,353,083	332,977	6.67	10.1
	Total General Plant			**251,808,020**	**94,733,629**	**156,809,795**	**20,790,553**	**8.26**	
	TOTAL DEPRECIABLE PLANT			**3,050,062,737**	**614,210,103**	**2,435,588,038**	**91,785,736**	**3.01**	**27.8**

(*) indicates that the historic gain/loss on retirments have been removed from the depreciation rate calcuation.

TERASEN GAS (VANCOUVER ISLAND) INC.

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2007

RELATED TO LIFE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2007	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	Intangible Plant								
401.0	Franchises and Consents	40-SQ	0	189,777	50,063	139,714	5,942	3.13	23.5
402.0	Intangible Plant	40-SQ	0	1,194,037	416,142	777,895	27,411	2.30	28.4
	Total Intangible Plant			**1,383,814**	**466,205**	**917,609**	**33,353**	2.41	
	Transmission Plant								
462.0	TP - Compressor Structures	30-R4	-5	10,148,764	2,219,551	7,929,213	377,905	3.72	21.0
463.0	TP - Measuring/Regulating Structures	30-R2.5	-5	6,056,273	1,727,823	4,328,450	173,666	2.87	24.9
464.0	TP - Other Structures	35-R3	-5	129,495	8,233	121,262	3,716	2.87	32.6
465.0	TP - Transmission Pipeline	60-R3	-10	221,257,782	49,586,037	171,671,745	3,820,531	1.73	44.9
466.0	TP - Compressor Equipment	33-R3	-10	45,122,851	8,411,858	36,710,993	1,439,026	3.19	25.5
467.1	TP - Measuring/Regulating Equipment	25-R2.5	-5	10,307,745	1,680,672	8,627,073	576,175	5.59	15.0
468.0	TP - Communications Equipment	15-R2	0	2,348,555	871,937	1,476,618	236,600	10.07	6.2
	Total Transmission Plant			**295,371,465**	**64,506,111**	**230,865,354**	**6,627,619**	2.24	
	Distribution Plant								
472.0	DS - Structures	28-L1	-5	1,455,159	569,949	885,210	46,671	3.21	19.0
473.0	DS - Services	55-R2.5	-50	122,548,256	14,742,217	107,806,039	2,345,649	1.91	46.0
474.0	DS - Meters/Regulators Installations	30-R2	0	15,569,726	3,855,682	11,714,044	537,563	3.45	21.8
475.0	DS - Mains	60-R3	-20	201,067,397	39,794,709	161,272,688	3,250,614	1.62	49.6
477.1	DS - Meters/Regulators Additions	25-R2	0	5,015,290	1,778,305	3,236,985	230,620	4.60	14.0
478.1	DS - Meters	25-R2	0	10,881,716	2,815,662	8,066,054	475,005	4.37	17.0
	Total Distribution Plant			**356,537,544**	**63,556,524**	**292,981,020**	**6,886,122**	1.93	
	General Plant								
482.2	Structures	25-R2	0	4,026,481 *	1,208,562	2,817,919	175,681	4.36	16.0
483.1	Computer Hardware	5-SQ	0	1,924,079 *	1,051,969	872,110	384,868	20.00	2.3
483.2	Computer Software (8 years)	8-SQ	0	15,758,816 *	3,299,262	12,459,554	1,969,890	12.50	6.3
483.2	Computer Software (5 years)	5-SQ	0	-	-	-	-	20.00	5.0
483.3	Office Furniture and Equipment	15-SQ	0	2,263,540 *	1,997,434	266,106	151,025	6.67	1.8
483.4	Furniture	20-SQ	0	59,597 *	7,113	52,484	2,980	5.00	17.6
484.0	Vehicles	6-L1	20	4,040,002 *	1,254,919	2,785,083	722,273	17.88	3.9
485.1	Heavy Work Equipment	15-R2	15	396,033 *	229,168	166,865	25,108	6.34	6.6
485.2	Heavy Mobile Equipment	15-L2.5	10	378,433 *	34,046	344,387	27,814	7.35	12.4
486.0	Small Tools/Equipment	20-SQ	0	5,540,499 *	2,610,915	2,929,584	277,160	5.00	10.6
488.1	Telephone Equipment	15-SQ	0	1,188,352 *	819,726	368,626	79,274	6.67	4.7
	Total General Plant			**35,575,832**	**12,513,114**	**23,062,718**	**3,816,072**	10.73	
	TOTAL DEPRECIABLE PLANT			**688,868,655**	**141,041,954**	**547,826,701**	**17,363,166**	**2.52**	**27.6**

(*) indicates that the historic gain/loss on retirments have been removed from the depreciation rate calcuation.

TERASEN GAS (WHISTLER) INC.

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2007

DRAFT - DEPRECIATION RELATED TO LIFE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2007	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	Intangible Plant								
401.0	Franchises and Consents	40-SQ	0	8,239	1,643	6,596	338	4.11	19.5
	Total Intangible Plant			**8,239**	**1,643**	**6,596**	**338**		
	Transmission Plant								
431.0	Mfg. Gas Land Rights	75-R4	0	3,625	637	2,988	50	1.38	59.8
432.0	Mfg. Gas Structures	40-SQ	0	2,878,938	924,528	1,954,410	71,840	2.50	27.2
433.0	Mfg. Gas Equipment	20-SQ	0	1,695,048	513,036	1,182,012	243,212	14.35	4.9
434.0	Mfg. Gas Holders	40-SQ	0	2,108,175	324,441	1,783,734	57,767	2.74	30.9
436.0	Mfg. Gas Compressor Equipment	25-SQ	0	37,896	11,420	26,476	1,961	5.18	13.5
437.0	Mfg. Gas Meas / Regulating Equipment	20-SQ	0	343,591	11,194	332,397	45,212	13.16	7.4
	Total Transmission Plant			**7,067,273**	**1,785,256**	**5,282,017**	**420,043**		
	Distribution Plant								
471.0	DS - Land Rights	75-R4	0	86,987	9,315	77,672	1,217	1.40	63.8
472.0	DS - Structures	28-L1	-5	205	92	113	7	3.26	16.9
473.0	DS - Services	55-R2.5	-50	2,890,836	331,381	2,559,455	55,993	1.94	45.7
474.0	DS - Meters/Regulators Installations	30-R2	0	808,837	241,338	567,499	26,972	3.33	21.0
475.0	DS - Mains	60-R3	-20	6,836,226	1,188,751	5,647,475	113,392	1.66	49.8
477.1	DS - Meters/Regulators Additions	25-R2	0	13,717	6,678	7,039	631	4.60	11.2
478.1	DS - Meters	25-R2	0	500,227	107,784	392,443	23,290	4.66	16.9
	Total Distribution Plant			**11,137,035**	**1,885,339**	**9,251,696**	**221,503**		
	General Plant								
482.1	Structures(Masonry)	25-R2	0	8,128	3,079	5,049	358	4.41	14.1
483.3	Office Furniture and Equipment	15-SQ	0	19,484	16,935 *	2,549	1,301	6.67	2.0
484.0	Vehicles	6-L1	20	64,260	20,018 *	44,242	10,289	16.01	4.3
485.1	Heavy Work Equipment	15-R2	15	77,949	58,554	19,395	3,610	4.63	5.4
486.0	Small Tools/Equipment	20-SQ	0	175,900	92,846 *	83,054	8,789	5.00	9.5
488.1	Telephone Equipment	15-SQ	0	45,832	41,174 *	4,658	3,058	6.67	1.5
	Total General Plant			**391,553**	**232,606**	**158,947**	**27,404**		
	TOTAL DEPRECIABLE PLANT			**18,604,100**	**3,904,844**	**14,699,256**	**669,288**	**3.60**	**22.1**

(*) indicates that the historic gain/loss on retirments have been removed from the depreciation rate calcuation.

TERASEN GAS INC.

TABLE 2. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2007
DEPRECIATION RELATED TO NET SALVAGE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2007	BOOK DEPRECIATION RESERVE	FUTURE NET SALVAGE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	Intangible Plant								
401.0	Franchises and Consents	40-SQ	0	99,236	-	-	-	-	
402.0	Intangible Plant	40-SQ	0	772,555	-	-	-	-	
402.1	Plant Acquisitions and Adjustments	40-SQ	0	62,457	-	-	-	-	
	Total Intangible Plant			**934,248**	**-**	**-**	**-**		
	Manufacturing Plant								
432.0	Manufacturing Gas Structures	40-SQ	0	450,708	-	-	-	-	
433.0	Manufacturing Gas Equipment	20-SQ	0	145,939	-	-	-	-	
434.0	Manufacturing Gas Holders	40-SQ	0	357,586	-	-	-	-	
436.0	Manufacturing Gas Compressor Equipment	25-SQ	0	53,309	-	-	-	-	
437.0	Manufacturing Gas Measuring/Regulating Equipment	20-SQ	0	309,447	-	-	-	-	
	Total Manufacturing Plant			**1,316,989**	**-**	**-**	**-**		
	LNG Plant								
442.0	LNG Gas - Structures	25-R3	-10	4,779,018	168,342	309,560	17,571	0.37	17.6
443.0	LNG Gas - Equipment	40-R3	-20	16,495,801	1,422,194	1,876,966	70,743	0.43	26.5
449.0	LNG Gas - Other Equipment	35-R3	-10	18,936,395	738,152	1,155,488	64,005	0.34	18.1
	Total LNG Plant			**40,211,214**	**2,328,688**	**3,342,014**	**152,319**		
	Transmission Plant								
462.0	TP - Compressor Structures	30-R4	-5	14,587,984	219,897	509,502	27,400	0.19	18.6
463.0	TP - Measuring/Regulating Structures	30-R2.5	-5	4,839,702	51,151	190,834	10,201	0.21	18.7
464.0	TP - Other Structures	35-R3	-5	5,842,863	50,326	241,817	8,325	0.14	29.0
465.0	TP - Transmission Pipeline	60-R3	-10	700,388,612	14,010,589	56,028,272	1,145,444	0.16	48.9
466.0	TP - Compressor Equipment	33-R3	-10	106,301,110	2,599,255	8,030,856	339,284	0.32	23.7
467.1	TP - Measuring/Regulating Equipment	25-R2.5	-5	27,913,211	225,619	1,170,042	99,324	0.36	11.8
467.2	TP - Telementry Equipment	17-R2	0	6,065,331	-	-	-	-	
467.3	TP - Measurement/Regulating Equipment	25-R2.5	-5	38,716	250	1,686	77	0.20	21.9
468.0	TP - Communications Equipment	15-R2	0	345,886	-	-	-	-	
	Total Transmission Plant			**866,323,415**	**17,157,087**	**66,173,009**	**1,630,056**		
	Distribution Plant								
472.0	DS - Structures	28-L1	-5	13,845,551	126,227	566,051	24,654	0.18	23.0
473.0	DS - Services	55-R2.5	-50	578,026,320	25,316,304	263,696,856	6,511,837	1.13	40.5
473.01	LILO - DS - Services	40-SQ	-50	43,302,554	4,759,119	16,892,158	478,342	1.10	35.3
474.0	DS - Meters/Regulators Installations	30-R2	0	127,327,914	-	-	-	-	
474.01	LILO - DS - Meters/Regulators Installations	30-SQ	0	16,070,133	-	-	-	-	
475.0	DS - Mains	60-R3	-20	790,729,371	35,643,935	122,501,939	2,963,207	0.37	41.3
475.01	LILO - DS - Mains	40-SQ	-20	39,743,548	2,389,318	5,559,392	157,183	0.40	35.4
476.0	DS - NGV Fuel Equipment	15-R3	0	570,858	-	-	-	-	
477.1	DS - Meters/Regulators Additions	25-R2	0	72,654,480	-	-	-	-	
477.2	DS - Telemetry	20-R2.5	0	5,527,676	-	-	-	-	
477.3	DS - Measuring/Regulating Equipment	15-R2.5	-5	163,151	9,194	(1,036)	-	-	1.0
478.1	DS - Meters	25-R2	0	180,537,629	-	-	-	-	
478.11	LILO - DS Meters	25-SQ	0	10,026,726	-	-	-	-	
487.2	DS - Instruments	30-R3	0	10,942,940	-	-	-	-	
	Total Distribution Plant			**1,889,468,851**	**68,244,097**	**409,215,359**	**10,135,222**		
	General Plant								
482.1	Structures (Frame)	25-R2	0	5,637,521	-	-	-	-	
482.2	Structures(Masonry)	25-R2	0	81,459,403	-	-	-	-	
482.3	Structures (Leased)	20-R1	0	1,586,223	-	-	-	-	
483.1	Computer Hardware	5-SQ	0	13,863,764	-	-	-	-	
483.20	Computer Software (8 Years)	8-SQ	0	71,038,304	-	-	-	-	
483.21	Computer Software (5 Years)	5-SQ	0	6,787,308	-	-	-	-	
483.3	Office Furniture and Equipment	15-SQ	0	4,248,230	-	-	-	-	
483.4	Furniture	20-SQ	0	20,073,829	-	-	-	-	
484.0	Vehicles	6-L1	20	695,457	(97,322)	(41,769)	(10,710)	(1.54)	3.9
485.1	Heavy Work Equipment	15-R2	15	189,165	(7,401)	(20,974)	(1,873)	(0.99)	11.2
485.2	Heavy Mobile Equipment	15-L2.5	10	312,945	40,502	(71,797)	(6,410)	(2.05)	11.2
486.0	Small Tools/Equipment	20-SQ	0	32,034,924	-	-	-	-	
487.2	NGV Cylinders	15-SQ	0	24,167	-	-	-	-	
487.3	VRA's	10-SQ	0	-	-	-	-	-	
488.1	Telephone Equipment	15-SQ	0	10,450,131	-	-	-	-	
488.2	Radio Equipment	15-SQ	0	4,992,872	-	-	-	-	
	Total General Plant			**253,394,243**	**(64,221)**	**(134,540)**	**(18,993)**		
	TOTAL DEPRECIABLE PLANT			**3,051,648,960**	**87,665,651**	**478,595,842**	**11,898,605**	**0.39**	

TERASEN GAS (VANCOUVER ISLAND) INC.

TABLE 2. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2007

DEPRECIATION RELATED TO NET SALVAGE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2007	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	Intangible Plant								
401.0	Franchises and Consents	40-SQ	0	189,777	-	-	-	-	0.0
402.0	Intangible Plant	40-SQ	0	1,194,037	-	-	-	-	0.0
	Total Intangible Plant			**1,383,814**	**-**	**-**	**-**		
	Transmission Plant								
462.0	TP - Compressor Structures	30-R4	-5	10,148,764	116,818	390,620	18,617	0.18	21.0
463.0	TP - Measuring/Regulating Structures	30-R2.5	-5	6,056,273	90,938	211,876	8,501	0.14	24.9
464.0	TP - Other Structures	35-R3	-5	129,495	433	6,042	185	0.14	32.6
465.0	TP - Transmission Pipeline	60-R3	-10	221,257,782	4,904,113	17,221,665	383,266	0.17	44.9
466.0	TP - Compressor Equipment	33-R3	-10	45,122,851	831,942	3,680,343	144,265	0.32	25.5
467.1	TP - Measuring/Regulating Equipment	25-R2.5	-5	10,307,745	88,456	426,931	28,513	0.28	15.0
468.0	TP - Communications Equipment	15-R2	0	2,348,555	-	-	-	-	0.0
	Total Transmission Plant			**295,371,465**	**6,032,700**	**21,937,477**	**583,347**		
	Distribution Plant								
472.0	DS - Structures	28-L1	-5	1,455,159	29,997	42,761	2,254	0.15	19.0
473.0	DS - Services	55-R2.5	-50	122,548,256	7,261,092	54,013,036	1,175,218	0.96	46.0
474.0	DS - Meters/Regulators Installations	30-R2	0	15,569,726	-	-	-	-	0.0
475.0	DS - Mains	60-R3	-20	201,067,397	8,150,724	32,062,755	646,257	0.32	49.6
477.1	DS - Meters/Regulators Additions	25-R2	0	5,015,290	-	-	-	-	0.0
478.1	DS - Meters	25-R2	0	10,881,716	-	-	-	-	0.0
	Total Distribution Plant			**356,537,544**	**15,441,813**	**86,118,552**	**1,823,730**		
	General Plant								
482.2	Structures	25-R2	0	4,026,481	-	-	-	-	0.0
482.3	Structures (Leased)	20-R1	0	1,338,776	-	-	-	-	0.0
483.1	Computer Hardware	5-SQ	0	1,924,079	-	-	-	-	0.0
483.2	Computer Software	5-SQ	0	15,810,140	-	-	-	-	0.0
483.3	Office Furniture and Equipment	15-SQ	0	2,263,540	-	-	-	-	0.0
483.4	Furniture	20-SQ	0	59,597	-	-	-	-	0.0
484.0	Vehicles	6-L1	20	4,040,002	(250,984)	(557,016)	(144,454)	(3.58)	3.9
485.1	Heavy Work Equipment	15-R2	15	396,033	(34,958)	(24,447)	(3,678)	(0.93)	6.6
485.2	Heavy Mobile Equipment	15-L2.5	10	378,433	(3,374)	(34,469)	(2,784)	(0.74)	12.4
486.0	Small Tools/Equipment	20-SQ	0	5,540,499	-	-	-	-	0.0
488.1	Telephone Equipment	15-SQ	0	1,188,352	-	-	-	-	0.0
	Total General Plant			**36,965,932**	**(289,316)**	**(615,933)**	**(150,917)**		
	TOTAL DEPRECIABLE PLANT			**690,258,755**	**21,185,197**	**107,440,097**	**2,256,160**	**0.33**	

TERASEN GAS (WHISTLER) INC.

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2007

DRAFT - DEPRECIATION RELATED TO NET SALVAGE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2007	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	Intangible Plant								
401.0	Franchises and Consents	40-SQ	0	8,239	-	-	-	-	0.0
	Total Intangible Plant			**8,239**	**-**	**-**	**-**		
	Transmission Plant								
431.0	Mfg. Gas Land Rights	75-R4	0	3,625	-	-	-	-	0.0
432.0	Mfg. Gas Structures	40-SQ	0	2,878,938	-	-	-	-	0.0
433.0	Mfg. Gas Equipment	20-SQ	0	1,695,048	-	-	-	-	0.0
434.0	Mfg. Gas Holders	40-SQ	0	2,108,175	-	-	-	-	0.0
436.0	Mfg. Gas Compressor Equipment	25-SQ	0	37,896	-	-	-	-	0.0
437.0	Mfg. Gas Meas / Regulating Equipment	20-SQ	0	343,591	-	-	-	-	0.0
	Total Transmission Plant			**7,067,273**	**-**	**-**	**-**		
	Distribution Plant								
471.0	DS - Land Rights	75-R4	0	86,987	-	-	-	-	0.0
472.0	DS - Structures	28-L1	-5	205	5	5	0	0.15	16.9
473.0	DS - Services	55-R2.5	-50	2,890,836	163,218	1,282,200	28,051	0.97	45.7
474.0	DS - Meters/Regulators Installations	30-R2	0	808,837	- 0	- 0	- 0	-	0.0
475.0	DS - Mains	60-R3	-20	6,836,226	243,479	1,123,766	22,563	0.33	49.8
477.1	DS - Meters/Regulators Additions	25-R2	0	13,717	- 0	-	-	-	0.0
478.1	DS - Meters	25-R2	0	500,227	-	-	-	-	0.0
	Total Distribution Plant			**11,137,035**	**406,702**	**2,405,971**	**50,614**		
	General Plant								
482.1	Structures(Masonry)	25-R2	0	8,128	-	-	-	-	0.0
483.3	Office Furniture and Equipment	15-SQ	0	19,484	-	-	-	-	0.0
484.0	Vehicles	6-L1	20	64,260	(3,336)	(9,516)	(2,213)	(3.44)	4.3
485.1	Heavy Work Equipment	15-R2	15	77,949	(8,932)	(2,760)	(514)	(0.66)	5.4
486.0	Small Tools/Equipment	20-SQ	0	175,900	-	-	-	-	0.0
488.1	Telephone Equipment	15-SQ	0	45,832	-	-	-	-	0.0
	Total General Plant			**391,553**	**(12,268)**	**(12,276)**	**(2,727)**		
	TOTAL DEPRECIABLE PLANT			**18,604,100**	**394,434**	**2,393,695**	**47,888**	**0.26**	

Terasen Gas Inc. and
Terasen Gas (Vancouver Island) Inc.
2010/11 Overhead Capitalization Methodology Review

June 10, 2009

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1.0 Summary of Findings

KPMG was retained by Terasen Gas Inc. (TGI) to review TGI and Terasen Gas Vancouver Island Inc.'s (TGVI) capital overhead cost allocation methodology. These costs are determined by applying various cost drivers to the pool of overhead costs to be allocated to capital.

No single regulatory guideline, statement or source exists that is universally accepted by industries and regulators as the definitive statement, definition or standard that prescribes the types of overhead costs that should be considered for capitalization. However, this topic has been the subject of discussion and comment and a body of evidence exists on the topic. From this evidence, a common principle arises:

> *That any assignment of indirect costs to a capital project should be done based upon some reasonable causal link or association with the capital activity.*

TGI and TGVI's methodology outlined in this report adheres to this principle.

KPMG has reviewed TGI and TGVI's documented policies and finds them reasonable and in accordance with industry standards and practices related to overhead capitalization. KPMG has also reviewed the cost drivers that have been used by TGI and TGVI to allocate overhead costs to capital, and KPMG has assessed the appropriateness of the activities to be capitalized. Accordingly, KPMG finds that the overhead capitalization results developed in this study and presented herein to be fair and reasonable and meet the criteria that TGI and TGVI outline in Appendix A for this review.

KPMG conducted the review of the 2010/11 capital overhead cost allocation methodology and resulting costs using 2009 budget figures as 2010/11 budget figures were not yet available. Our findings and conclusions are therefore limited accordingly. It is TGI and TGVI's intention to apply this methodology in 2010 onwards.

Table 1 below summarizes the 2009 estimates of the amount of Operations and Maintenance (O&M) costs related to capital in both TGI and TGVI.

Table 1 - 2009 Summary of Budgeted Capitalized Overhead Costs

Company	Total Gross O&M	Total Capitalized Overhead	% of Total Gross O&M Capitalized
TGI	194,207,182	15,861,019	8.17%
TGVI	29,085,010	1,517,916	5.22%

2.0 Purpose of the Report

Purpose

KPMG was retained by Terasen Gas Inc. (TGI) to review TGI and Terasen Gas Vancouver Island Inc's (TGVI) capital overhead cost allocation methodology. KPMG conducted the review of the 2010/11 capitalized overhead costs using 2009 budget figures as 2010/11 budget figures were not yet available.

Specifically, KPMG was engaged to assess the reasonableness of:

- TGI and TGVI's capital overhead cost allocation methodology;
- the activities allocated to capital;
- the cost drivers; and
- the resulting overhead capitalization rate.

Report Structure

Tables 2 and 3 below describe the sections and appendices in this report.

Table 2 – Report Body Section Descriptions

Section	Description
1.0: Summary of Findings	Includes a brief discussion of KPMG's review approach and summary of findings
2.0: Purpose of Report	Outlines the structure of the report and provides a brief explanation of each section
3.0: Background	Provides an overview of the organizational structure. Note: TGVI was not previously part of the Terasen group of companies at the time the last TGI review was conducted
4.0 Summary of TGI and TGVI's 2010/11 Overhead Capitalization Methodology	Provides a high level summary of the components of the overhead capitalization methodology
5.0: KPMG Review Approach	Provides an explanation of KPMG's approach to reviewing TGI and TGVI's capital overhead cost allocation methodology including the criteria used by KPMG during our analysis

Section	Description
6.0: Comparison to Other Utilities	Provides a summary of the publicly available information KPMG used during our analysis of the overhead capitalization methodology
7.0: KPMG Findings	Provides KPMG's findings as to the reasonableness of the capital overhead cost allocation methodology and resulting costs- using 2009 budget figures as 2010/11 figures were not yet available

Table 3 – Report Appendices Section Descriptions

Appendix	Description
A: TGI and TGVI's Overhead Capitalization Evaluation Criteria	Contains a detailed description of the criteria used by TGI and TGVI to develop the capital overhead cost allocation methodology
B: TGI and TGVI's Capital Overhead Cost Allocation Methodology	Contains a detailed description of the methodology used by TGI and TGVI to develop the capital overhead cost allocation methodology
C: TGI and TGVI's Overhead Capitalization Questionnaire	The questionnaire used by TGI and TGVI to collect information on overhead capital costs from management and staff
D: Accounting and Regulatory Guidance.	Contains a description of guidance provided by accounting bodies and regulators
E: References	Contains a description of the research documents KPMG consulted to reach its conclusions

Scope Limitations

KPMG's assessment of the overhead capitalization methodology and related costs involved relying on data and information provided to KPMG by TGI and TGVI. The data provided by TGI and TGVI was analyzed by KPMG in carrying out the assessment of the methodology against TGI and TGVI's overhead capitalization evaluation criteria.

KPMG has considered the reasonableness of the information provided by TGI, however has not conducted an audit. KPMG has assumed the completeness, accuracy and fair presentation of the information, data or advice provided by TGI. TGI maintains responsibility for the accuracy and completeness of the data and information associated with the capital overhead cost allocation methodology.

KPMG conducted the review of the 2010/11 capital overhead cost allocation methodology and resulting costs using 2009 budget figures as 2010/11 budget figures were not yet available. Our findings and conclusions are therefore limited accordingly.

3.0 Background

TGI Organizational Structure

TGI and TGVI provide gas distribution services in BC. Both TGI and TGVI are regulated subsidiaries of TI. Figure 1 illustrates the relationship between these entities.

Figure 1 – Organizational Structure

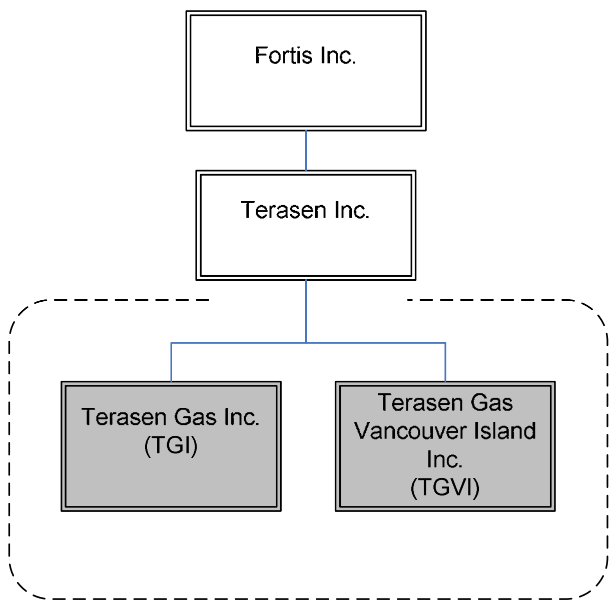


Table 4 below summarizes the formal company names for each of the entities discussed in the report, matched to the acronyms that have been used for brevity.

Table 4 - Glossary of Company Names

Name Used in this Report	Formal Company Name
TI	Terasen Inc.
TGI	Terasen Gas Inc.
TGVI	Terasen Gas (Vancouver Island) Inc.

4.0 Summary of TGI and TGVI's 2010/11 Overhead Capitalization Methodology

In 2009 TGI and TGVI undertook a project to review the capital overhead cost allocation methodology, activities and resulting overhead costs to be capitalized. This section summarizes the key components of that methodology

Appendix B contains a more detailed description of TGI and TGVI's capital overhead cost allocation methodology.

Capital Overhead Cost Allocation Model

In order to determine the overhead costs to be allocated to capital, TGI and TGVI first reduced the total O&M cost pool by excluding a number of overhead activities that did not qualify under TGI and TGVI's eligible overhead costs to be allocated to capital. This resulted in a net O&M figure to be allocated.

Figure 2 below illustrates the high level methodology applied to allocate O&M overhead costs to capital at TGI and TGVI.

Figure 2 – Overhead Cost Allocation Model

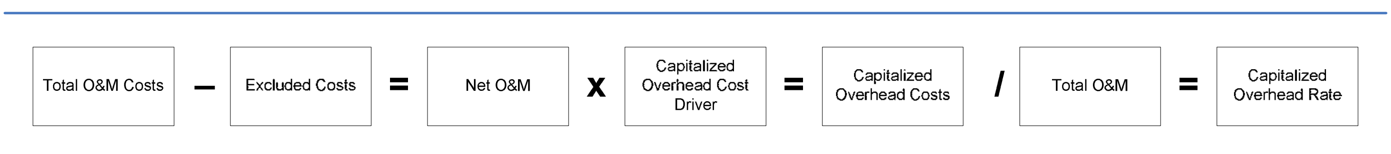


Figure 3 shows the key cost components included in the net O&M cost pool and the drivers applied to each to determine the percentage of overhead costs to be allocated to capital.

Figure 3 – Overhead Cost Allocation Drivers

Activities	Drivers
• Distribution • Transmission • Finance and Regulatory Affairs • Marketing • Business Services	Labour Time Estimate
• Facilities Management • IT Services • HR Advisory Services	Incremental FTE Support
• Future Employee Benefits • TGVI Shared Services	Composite Average
• Insurance	Ratio of Capital versus O&M Budget

Overhead Activities Allocated to Capital

Table 5 below provides a summary of the overhead activities allocated to capital.

Table 5 - Overhead Activities Allocated to Capital

Activity	Description
Distribution	Distribution activities include conducting negotiations regarding capital projects, providing direct oversight of and guidance on construction projects, providing supervision and oversight of staff implementing capital projects, coordinating and scheduling field capital work, planning and design and management of capital installations.
Transmission	Transmission activities include conducting negotiations regarding capital projects, providing direct oversight of and guidance on construction projects, providing supervision and oversight of staff implementing capital projects, as well as conducting field work to implement capital projects.
Finance and Regulatory Affairs	Finance and Regulatory Affairs activities include filing applications and preparation of quarterly/annual reporting related to capital, tracking, settlement and reporting of new capital additions, budgeting, tracking and reporting of capital activity, as well as processing invoices and other accounts payable activities related to capital projects.
Marketing	Marketing activities include communications with stakeholders for specific capital projects, and providing management and oversight of escalated issues related to capital.
Business Services	Business Services activities include conducting negotiations regarding capital projects, providing direct oversight of and guidance on construction projects, providing supervision and oversight of staff implementing capital projects, procuring and managing capital inventory, performing quality control assurance activities, processing capital work orders, providing design specifications and preparing purchase orders.
Facilities Management	Facilities activities include managing the facilities which field staff use to perform capital projects.
IT Services	IT Support activities include providing the IT infrastructure (hardware, software, systems) required for staff to implement capital projects.
HR Advisory Services	HR Advisory activities include client advisory, performance management, recruiting, staffing and relief services related to capital projects. HR Advisory services only exist in TGI.
Future Employee Benefits	Future Employee Benefits costs relate to accrued pension costs to be paid out to employees in the future. A portion of these costs related to employees involved in capital activities have been allocated in the methodology.
TGVI Shared Services	TGI provides several shared services on behalf of TGVI. TGI has implemented a detailed shared services model for allocating costs to TGVI based on a number of drivers which calculate TGI's proportionate cost to service TGVI. Many of these shared services help to support capital projects, either directly or indirectly.
Insurance	Insurance premiums for commercial liability policies are portioned to capital based on proportion of dollars spent on Capital projects versus O&M expenditure. For the 2009 budget this allocation represented 30%.

Overhead Capital Cost Drivers

The following drivers are used in TGI and TGVI's capital overhead cost allocation methodology.

- **Labour Time Estimate**

  Management followed TGI and TGVI's overhead capitalization policy and used consistent templates to identify which non-project specific capital support and oversight activities, which are not otherwise directly charged out to capital, to capture in the allocation model. They further conducted a detailed review of each cost centre to determine the percentage of each labour group (i.e. management, non-management) time allocated to performing those activities.

  Labour time estimate was used to allocate overhead costs for Distribution, Transmission, Finance and Regulatory Affairs, Marketing and Business Services.

- **Incremental FTE Estimate**

  A portion of IT Services, Facilities Management and HR Advisory Services support functions would vary with the level of capital activity. The portion of activity that could vary is eligible for inclusion in the overhead allocated to capital.

- **Composite Average**

  The composite average was determined by calculating a weighted average of the percentage of O&M costs allocated to capital across all cost centres that utilize labour time estimate and incremental FTE estimate as drivers.

  The composite average was used to allocate overhead costs for Future Employee Benefits and a recovery for the capital portion of shared services provided by TGI to TGVI.

- **Ratio of Capital Budget versus O&M Budget**

  Insurance premiums for commercial liability policies are allocated to capital based on proportion of dollars spent on Capital projects versus O&M expenditure. For the 2009 budget this allocation represented 30% for TGI and 44.4% for TGVI.

Table 6 below provides a description of the percentage of O&M costs capitalized for each service and cost driver for each service.

Table 6 - Basis of 2009 Overhead Allocations

Service	TGI % Capitalized	TGVI% Capitalized	Cost Driver
Distribution	19.77%	9.92%	Labour time estimate
Transmission	3.07%	4.33%	Labour time estimate
Finance and Regulatory Affairs	8.84%	0.00%	Labour time estimate
Marketing	0.65%	0.00%	Labour time estimate
Business Services	14.54%	8.28%	Labour time estimate
Facilities Management	17.04%	5.19%	Incremental FTE support
IT Services	16.80%	5.11%	Incremental FTE support
HR Advisory Services	16.44%	0.00%	Incremental FTE support
Future Employee Benefits	7.96%	4.31%	Composite average
TGVI Shared Services	7.96%	7.96%	Composite average
Insurance	30.03%	44.40%	Ratio of Capital versus O&M budget
President	0.00%	0.00%	Not allocated
Human Resources and Operational Governance	0.00%	0.00%	Not allocated

Overhead Capital Costs

Tables 7 and 8 below summarize the costs allocated to capitalized overhead for each service in each of TGI and TGVI.

Table 7 - TGI 2009 Budgeted Capitalized Overhead Costs

Service	Total Gross O&M	Total Capitalized Overhead	% of Total Gross O&M Capitalized
Distribution	35,908,454	7,097,975	19.77%
Transmission	16,945,746	520,755	3.07%
Finance and Regulatory Affairs	9,660,018	853,684	8.84%
Marketing	66,278,049	429,475	0.65%
Business Services	18,329,403	2,665,151	14.54%
Facilities Management	5,579,773	951,013	17.04%
IT Services	14,445,554	2,427,258	16.80%
HR Advisory Services	1,665,075	273,706	16.44%
Future Employee Benefits	6,332,291	504,334	7.96%
TGVI Shared Services	(4,994,175)	(397,760)	7.96%
Insurance	1,782,743	535,427	30.03%
President	15,494,327	0	0.00%
Human Resources and Operational Governance	6,779,924	0	0.00%
Total	**194,207,182**	**15,861,019**	**8.17%**

Table 8 - TGVI 2009 Budgeted Capitalized Overhead Costs

Service	Total Gross O&M	Total Capitalized Overhead	% of Total Gross O&M Capitalized
Distribution	5,800,055	575,203	9.92%
Transmission	5,549,126	240,423	4.33%
Finance & Regulatory	325,429	0	0.00%
Marketing	6,886,329	0	0.00%
Business Services	631,023	52,260	8.28%
Facilities Management	1,487,493	77,235	5.19%
IT Services	633,990	32,399	5.11%
HR Advisory Services	0	0	0.00%
Future Employee Benefits	1,213,700	52,326	4.31%
TGVI Shared Services	4,994,175	397,760	7.96%
Insurance	203,422	90,310	44.40%
President	1,360,268	0	0.00%
Human Resources and Operational Governance	0	0	0.00%
Total	**29,085,011**	**1,517,916**	**5.22%**

5.0 KPMG Review Approach

This section summarizes KPMG's approach to completing the review of TGI and TGVI's overhead capitalization methodology and related costs. Our work plan was developed in collaboration with TGI management in order to meet the objectives of this review.

Our work plan incorporated the following steps:

- **Step 1: Reviewed company policy and process documentation**. In this step, KPMG obtained and reviewed all relevant documentation relating to the allocation of overhead costs to capital at TGI and TGVI in order to obtain a thorough understanding of TGI and TGVI's capital overhead cost allocation methodology.
- **Step 2: Participated in interviews with company officials**. In this step, KPMG participated in select interviews held by TGI with senior representatives from the operating areas. The purpose of this step was to gain an understanding of the specific activities within TGI and TGVI that may be related to capital. This step also provided KPMG with a good understanding of TGI and TGVI's organizational structure and its approach to the acquisition, construction and installation of capital assets.
- **Step 3: Documented and reviewed regulatory and accounting policy guidance**. In this step, KPMG researched the guidance provided by various accounting and regulatory authorities on the topic of overhead capitalization. The objective of this step was to ensure that the approach adopted in TGI and TGVI's capital overhead cost allocation methodology was consistent with a cross-section of current industry standards and practices. A summary of the sources of our research is provided in Appendix E.
- **Step 4: Assessed the reasonableness of TGI and TGVI's capital overhead cost allocation criteria.** In this step, we reviewed TGI and TGVI's criteria for overhead capitalization, as documented in Appendix A, against external guidance from regulators and the practices of other Canadian utilities as observed through a review of regulatory filings in various jurisdictions.

- **Step 5: Assessed the reasonableness of TGI and TGVI's capital overhead cost allocation methodology.** In this step, we assessed the alignment between TGI and TGVI's methodology against internal policy, external guidance from regulators and the practices of other Canadian utilities as observed through a review of regulatory filings in various jurisdictions. Specifically, we:
  - Reviewed the methodology utilized in the model against TGI and TGVI's documented overhead capitalization policy;
  - Reviewed the overhead capitalization model for formula accuracy; and
  - Validated costs used in the capital overhead cost allocation methodology against SAP (Terasen's accounting system of record) system reports.
- **Step 6: Assessed the reasonableness of the overhead activities allocated to capital.** In this step we assessed the reasonability of the overhead activities allocated to capital against internal policy and external guidance (e.g. IFRS).
- **Step 7: Assessed the reasonableness of the drivers used to allocate overhead costs to capital.** In this step we assessed the reasonability of drivers used in the overhead activities allocated to capital against internal policy, external guidance from regulators and the practices of other Canadian utilities as observed through a review of regulatory filings in various jurisdictions.
- **Step 8: Assessed the reasonableness of the resulting overhead capitalization rate.** In this step we assessed the reasonability of the resulting overhead capitalization rate against internal policy, external guidance from regulators and the practices of other Canadian utilities as observed through a review of regulatory filings in various jurisdictions.
- **Step 9: Prepared report.** In this step, KPMG prepared this report to summarize the results of the review.

6.0 Canadian Utilities Practices

KPMG conducted a review of other Canadian utility practices as observed through regulatory filings, regulator decisions and KPMG's knowledge of practices in several utilities.

The utilities reviewed are summarized in the Table 9 below.

Table 9 - Utility Research

Utility	Jurisdiction	Utility	Jurisdiction
TGVI	BCUC	Hydro One	OEB
TGI	BCUC	Pacific Northern Gas	BCUC
BC Transmission Co	BCUC	EPCOR	AUC
BC Hydro	BCUC	AltaGas	AUC
Ottawa Hydro	OEB	ENMAX	AUC
ENMAX	AUC	NB Power	NBEUB
ATCO	AUC	Union Gas	OEB
PUC Distribution	OEB	Fortis AB	AUC

Based on the research of other Canadian utility practices, there is a relatively wide range of practices with respect to capitalizing overhead among utilities. This reflects the considerable discretion inherent in accounting and regulatory guidance.

The review of other Canadian utility practices revealed the following observations:

- Capital overhead cost allocation methodologies vary greatly in methodology and the rate calculation; however many apply a percentage to a capital expenditure amount;
- Some utilities use a single allocation factor (i.e. % of total O&M vs. capital), while others use multiple allocators (i.e. labour time estimate, composite averages etc) specific for each activity;

- Some utilities apply fully-allocated capital overhead cost allocation methodologies which is to say that capitalized overhead costs include a share of the indirect and fixed costs that do not vary directly with the level of capital activity (i.e. administration and general expenses); while others utilize an incremental capital overhead cost allocation methodology where eligible costs are defined as those that would not exist if capital activity ceased; and
- There is little consistency with respect to what cost components were included in the overhead capitalization rate; costs ranged from shared services, distribution, gas supply and transmission, to general administration and overhead.

A detailed list of the reference sources KPMG consulted is provided in Appendix E.

7.0 KPMG Findings

This section presents KPMG's findings of the review of TGI and TGVI's capital overhead cost allocation methodology and related costs.

The capital overhead cost allocation methodology and costs reviewed meet the criteria that TGI has outlined in its capitalization policy and are in accordance with industry standards and practices related to overhead capitalization.

Overall, KPMG finds that the capital overhead cost allocation methodology and costs to be fair and reasonable.

Reasonability of the Capital Overhead Cost Allocation Criteria

In Step 4 KPMG reviewed the criteria TGI and TGVI applied to evaluate the capital overhead cost allocation methodology provided in Appendix A against external guidance from regulators and the practices of other Canadian utilities as observed through a review of regulatory filings in various jurisdictions.

KPMG finds that the evaluation criteria used to evaluate the capital overhead cost allocation methodology to be fair and reasonable.

Reasonability of the Capital Overhead Cost Allocation Methodology

In Step 5 KPMG reviewed TGI and TGVI's capital overhead cost allocation methodology against TGI and TGVI's capital overhead cost allocation criteria.

Table 10 below summarizes the assessment of TGI and TGVI's current capital overhead cost allocation methodology against TGI's evaluation criteria set out in Appendix A.

Table 10 - Evaluation of Overhead Capitalization Methodology

Key: S = satisfies the evaluation criteria
SS = somewhat satisfies the evaluation criteria
NS = does not satisfy the evaluation criteria

Evaluation Criteria	Assessment	Explanation
Defensible Cost Causation Linkage	SS	➢ Internal policy provides guidance requiring a reasonable causal link or association with the capital activity for costs to be allocated to capital; however some of the IT Services and HR Advisory Services are inherently difficult to directly relate to capital, as they are the furthest removed from actually performing the capital work.
Distinguishable from Directly Allocated Capital Costs	S	➢ Overhead costs allocated using this methodology are those that are not directly charged to capital and represent overhead activities.
Transparency	S	➢ The methodology implemented for this update relies on formal documentation at each step of the process. It thus addresses the criteria for transparency.
Freedom from Bias	S	➢ TGI and TGVI's documented methodology and internal guidance in conjunction with TGI Finance's review of management's estimates, effectively safeguards the methodology from bias.
Stability	S	➢ The methodology can be applied consistently year over year without resulting in major variances in amounts capitalized.
Accuracy of Underlying Data	S	➢ While KPMG was not engaged to conduct a review of the accuracy of the costs being allocated in the model, we verified cost data used in the capital overhead cost allocation methodology against SAP system reports. SAP is Terasen's financial system of record and supports audited financial results. ➢ As detailed in Appendix B, TGI and TGVI management undertook a detailed review of all employee time related to capital activities. The level of detail apparent in the data provided by management is significant which enhances reliability of the underlying data.
Flexibility / Adaptability	S	➢ The capital overhead cost allocation methodology and integrated Excel model facilitates updates, and thus supports the criteria

Evaluation Criteria	Assessment	Explanation
Cost-Effectiveness • Low implementation cost	SS	➢ The capital cost allocation methodology requires time and effort for management to update, however it is much more accurate than utilizing a simpler allocation methodology. Additional time and effort was required in this iteration to understand the restrictions on activities eligible for allocation to capital under IFRS. ➢ The Excel model used to implement the methodology is straightforward and easily updated.
• Low on-going costs	S	➢ The capital cost allocation methodology requires time and effort for management to update, however it is much more accurate than utilizing a simpler allocation methodology. ➢ The Excel model requires little in the way of cost to maintain and update it.

KPMG finds the methodology to be reasonable and in accordance with internal policy, external guidance from regulators and industry standards and practices related to overhead capitalization.

Reasonability of the Overhead Activities Allocated to Capital

In Step 6 KPMG conducted a high level review of the overhead activities allocated to capital against internal policy and external guidance.

KPMG believes that TGI's capital overhead cost allocation methodology attempts to respect IFRS guidance by attempting to exclude items not directly related to capital projects.

Given the high level scope of this review and the fact that the application of IFRS is subject to significant judgment KPMG finds the activities allocated to capital to be reasonable with the following comment:

Certain activities are difficult to directly relate to capital, including IT Services and HR Advisory Services as they are the furthest removed from actually performing the capital work and represent support functions; however TGI has applied a somewhat reasonable methodology to identify where these support activities relate to capital projects.

KPMG expects that TGI will evolve their capital overhead allocation methodology, with respect to overhead activities allocated to capital, as clarity around IFRS guidance improves and the utility industry's interpretation of IFRS guidance matures.

Reasonability of the Drivers Used to Allocate Costs to Capital

In Step 7 KPMG assessed the reasonability of the drivers used to allocate overhead costs to capital.

- **Labour Time Estimate**

  KPMG reviewed the method that TGI and TGVI management utilized in order to determine the amount of time spent on overhead activities related to capital.

  This driver was chosen as it most accurately reflects the key component of the overhead cost to be allocated to capital - labour.

  <u>KPMG finds that labour time estimate is a reasonable driver to allocate labour related overhead costs to capital.</u>

- **Incremental FTE Estimate**

  KPMG reviewed TGI management's assessment of potential work force reduction in the IT Services, Facilities Management and HR Advisory Services support functions should capital activities cease.

  This driver, rather than labour time estimate, was chosen as these support functions relate to non-labour costs related to employees across the entire organization. Therefore, a driver that reflects incremental amount of work required to perform these functions with the presence of capital activities is the most appropriate.

  The 214 FTEs that management identified as incremental savings should capital activities cease, represent approximately 17% of TGI's workforce.

  <u>KPMG finds that incremental FTE estimate is a reasonable driver to allocate costs of support services to capital.</u>

- **Composite Average**

  The composite average was calculated and applied to corporate overhead costs; these include future employee benefits and a recovery for the capital portion of shared services provided by TGI to TGVI.

  This driver, rather than labour time estimate or incremental FTE estimate, was chosen as future employee benefits and shared services relate to non-labour costs driven by the number of employees across the entire organization. Therefore, a driver that reflects the weighted average of the percentage of overhead costs related to capital across all departments is the most appropriate.

  <u>KPMG finds that the composite average is a reasonable driver to allocate costs of support services to capital.</u>

- **Ratio of Capital Budget versus O&M Budget**

  Insurance premiums for commercial liability policies are allocated to capital based on proportion of dollars spent on Capital projects (excluding CPCN) versus O&M expenditure. For the 2009 budget this allocation represented 30% for TGI and 44.4% for TGVI.

  This driver, rather than those above, was chosen as insurance premiums relate to both capital and operating activities. Therefore, a driver that reflects the annual liability associated with all capital related spending is the most appropriate.

  <u>KPMG finds that the ratio of capital budget versus O&M budget is a reasonable driver to allocate costs of support services to capital.</u>

Reasonability of the Capitalization Rate

In Step 8 KPMG reviewed regulatory guidance and practices in other Canadian utilities in order to compare capitalization rates.

KPMG finds that generally, utilities in Canada tend to capitalize 10 to 20 percent of gross O&M costs; however some utilities capitalize fewer costs due to the nature of their businesses having relatively lower proportion of capital costs.

Table 11 summarizes the overhead capitalization rates in use at other Canadian utilities.

Table 11 – Comparative Overhead Capitalization Rates

Utility	Jurisdiction	Rate
ENMAX	AUC	19%
Pacific Northern Gas	BCUC	19.04%
Hydro One	OEB	16.6%
Ottawa Hydro	OEB	20.9%

Several factors should be taken into consideration when comparing the above rates to TGI and TGVI including changes resulting from the implementation of IFRS guidelines, the activities allocated to capital in those organizations and the capital overhead cost allocation methodology they use.

<u>KPMG finds the capitalization rate applied to the overhead costs in TGI and TGVI to be reasonable.</u>

Appendix A – TGI and TGVI's Overhead Capitalization Evaluation Criteria

Methodologies for overhead capitalization address a set of formal, objective criteria that speak to company and policy objectives. The criteria that TGI apply to their capital overhead cost allocation methodology are as follows:

- **Defensible Cost Causation Linkage**. To conform to accounting guidelines, the methodology should show a direct causal link between capitalized overhead costs and capital activity.
- **Distinguishable from Directly Allocated Capital Costs**. The overhead costs must be distinguished from those that are directly charged to capital
- **Transparency**. The methodology and calculations should be easy to follow and to understand by internal users and by external observers (i.e., regulators). This will facilitate acceptance of the methodology.
- **Freedom from Bias**. The methodology should not tend to allocate an undue proportion of costs toward either operating or capital activities.
- **Stability**. The methodology should not result in disproportionately large variations in the amounts of capitalized overhead from year-to-year.
- **Accuracy of Underlying Data**. Any data used in the methodology should be accurate and able to be relied upon. The data should provide an appropriate measure of the underlying volume of activity or output.
- **Flexibility/Adaptability**. The methodology should accommodate changes in organizational structure, business processes, and information systems with reasonable ease. Thus, the methodology should be dynamic: it should be relatively easy to update and keep current as the organization evolves. To the extent possible, it should automatically adjust for changes in circumstance
- **Cost-Effectiveness.** In evaluating different methodologies, TGI should ensure that they are cost-effective to implement. Additional accuracy may require significant additional cost, and thus an appropriate balance is required between precision and cost. In evaluating cost-effectiveness, two different perspectives are relevant:
  - **Low implementation cost.** All else being equal, the methodology should be capable of being implemented at a reasonable cost.
  - **Low on-going costs.** The methodology should have relatively low costs of upkeep. Further, it should reduce the administrative, record-keeping and reporting burden imposed on operating staff. The methodology should also integrate easily with the process used to prepare company financial statements.

Appendix B – TGI and TGVI's Capital Overhead Cost Allocation Methodology

In this Appendix, we summarize the capital overhead cost allocation methodology used by TGI and TGVI to complete the review and update of the overhead capitalization methodology and related costs.

A. Capital Overhead Cost Allocation Methodology

TGI's work plan incorporated the following steps:

- **Step 1: Interview company officials**. In this step, TGI finance staff interviewed senior representatives from each department to understand and identify those activities that appear to support, either directly or indirectly, capital projects at TGI and TGVI. The purpose of this step was to gain an understanding of the specific activities within TGI and TGVI that may be eligible to have costs allocated to capitalized overhead.
- **Step 2: Document regulatory and accounting policy guidance**. In this step, TGI researched the guidance provided by various accounting and regulatory authorities on the topic of overhead capitalization. The objective of this step was to ensure that TGI's Capital Overhead Cost Allocation Methodology was consistent with a cross-section of current industry standards and practices.
- **Step 3: Develop criteria for the capital overhead cost allocation methodology.** Based on the initial steps above, TGI developed a set of criteria to be used to evaluate its methodology for estimating the amount of overhead costs associated with capital projects. The criteria are provided later in this section.
- **Step 4: Document TGI and TGVI's capital overhead cost allocation methodology**. In this step, TGI prepared a statement that summarizes TGI and TGVI's guidelines for overhead capitalization. This statement appears in the Internal Guidelines section below. This was used as an information guide for management when compiling information for this review and update.
- **Step 5: Assess reasonableness of TGI and TGVI's capital overhead cost allocation methodology.** In this step, TGI assessed its methodology for overhead capitalization against the criteria noted in Step 3 above. TGI evaluated its methodology against internal guidance, guidance from regulators, accounting bodies and other Canadian utilities.

- **Step 6: Internal data collection.** In this step TGI finance staff collected data from all relevant departments within each operating company using standardized templates. To support proposed allocations from any given department, company management prepared the following:
  - A written description of the specific activities within the department that support capital projects.
  - Estimates of the percentage of the 2009 and 2010/11 budgeted cost of activities that should be allocated to capitalized overhead (percentages below 5% were removed as deemed too insignificant of a causal link), and
  - Supporting documentation with respect to the basis of the proposed cost allocation factors.

  This step was intended to provide an audit trail for the costs to be allocated to capitalized overhead.

- **Step 7: Review internal survey results.** In this step, TGI finance staff reviewed the data assembled by company management in the step above. They checked that the information provided was consistent with TGI and TGVI's internal policies for overhead capitalization as documented in Step 4 and with the information received from the initial interview process (Step 1). TGI also verified the accuracy of any supporting calculations and cross-checked the information provided with respect to the costs of activities and cost drivers used against budget data for TGI and TGVI. Where required and appropriate, departments were asked to review and/or update the calculations provided in the previous step.

  Overall, this step was very important to the overall integrity of this study update process: TGI personnel worked to ensure that the allocation process was reasonable and that it was applied consistently across the company.

- **Step 8: Develop capital overhead cost allocation model.** In this step, TGI built a capital overhead cost allocation model using 2009 budget information and applied the percentages collected from each department in Step 6 above.

  To build the model, financial information was downloaded for each cost centre from SAP. Ineligible costs were identified and removed from the allocation.

  TGI finance staff worked with Managers to apply the appropriate cost driver to their cost centres in order to determine the percentage of cost to be allocated to capital.

The results were aggregated by department using a weighted average calculation.

- **Step 9: Prepare summary report.** In this step, TGI prepared a summary report to document and summarize the results of the update process.

B. Internal Guidelines

While the OEB and CICA, as noted above, provide general guidance with respect to capitalized overhead costs, TGI and TGVI have prepared their own internal guidelines to provide more specific direction as to the nature, type, and quantum of costs that should be allocated to capitalized overhead. The definition of capitalized overhead costs that has been adopted for this review and update is as follows:

> *Those items that are directly attributable to bringing the capital asset to the "location and condition necessary for its intended use" should be recognized as a capital cost. In addition to costs charged directly to the capital asset, other costs which are directly attributable to bringing the assets to their location and condition necessary for intended use but are not directly charged to the asset, should be allocated to the asset cost.*
>
> *Overheads capitalized as described below represent a reasonable and appropriate amount of costs that are directly linked to capital activity (new assets acquired or constructed) but, due to the onerous nature of capturing these costs, are not directly assigned to individual capital projects. In order to qualify as capitalized overhead:*
>
> - *there must be an established causal link or association of these costs with capital activity;*
> - *these overhead costs must be distinguished from those that are directly charged to capital.*

TGI's has adopted a time-based methodology for identifying certain costs that are directly attributable to, or can be linked to, capital related activity. The use of a 3-5 year time horizon accounts for the effect that many of the overhead costs captured in the process will not vary directly with the level of capital spending in the short term. They could be eliminated in the absence of a capital program but, given that TGI and TGVI do have capital programs, they are relatively fixed in nature and may not change materially with changes in capital spending from year to year.

C. Overhead Capital Activities

Functions that have costs allocated to capitalized overhead generally fall into one of the three categories noted below. While the boundaries between these types of activities are not always clear, the categories do help to provide a conceptual framework to help identify and evaluate those costs eligible for capitalized overhead:

1. Non-Project Specific Capital Support.

This includes formulating, evaluating, initiating, designing, approving and implementing capital additions. These costs are captured in capitalized overhead because:

- It is impractical to capture costs directly to specific capital projects;
- These functions relate to many capital projects rather than specific or identified ones

An example of this would be the approval of capital expenditures.

2. Oversight of Activities Directly Related to Capital Projects

These costs include the direct supervision, cost control and reporting that are in direct support of capital projects.

An example of this would be the supervision of construction departments.

3. Support Functions and Infrastructure

This category covers the support functions and infrastructure networks that enable departments that are directly involved in performing capital work.

An example of this would be found in the areas of Human Resources (specifically, HR Advisory), Facilities, and IT.

Because the last category of cost has the least direct relationship to capital projects, TGI and TGVI implemented a “test” to ensure that any cost centre or activity that allocates costs to capitalized overhead has some causal linkage with capital spending. This test applies only to Support Functions and Infrastructure, and is as follows:

Would the workload of this function be materially reduced if the company ceased to undertake all capital projects?

As a materiality threshold, the workload for that function would need to be reduced by the equivalent of at least ½ of a Full-Time Employee (or “FTE”) under the scenario in which all capital projects at TGI or TGVI cease.

If the function would not have its workload reduced by at least ½ an FTE under a scenario in which capital projects cease, then none of the costs of that function should be allocated to capitalized overhead.

D. Nature of Capitalized Overhead Costs

Capitalized overhead costs can be distinguished from:

- **Costs charged directly to capital.** These are costs that are charged directly to capital projects and that therefore form part of the direct capital cost of the associated assets. Such costs include the costs of materials and construction labour, as well as any purchased services (e.g. outside contracting) that may be associated with installation of the asset. At TGI and TGVI, vehicle costs are charged directly to capital work.
- **Costs charged directly to operating expenses.** These costs appear in the income statement for TGI and TGVI in the period concerned. These costs include any costs that are not identified as being related to capital projects. They thus encompass a wide range of costs, including costs associated with customer billing and service, most general and administrative costs, and costs associated with maintenance activities.

Capitalized overhead, in contrast to the cost elements above, reflects those costs that relate to capital projects but that have not been specifically identified with any individual project.

Appendix C – TGI and TGVI's Overhead Capitalization Questionnaire

Overview

Terasen Gas is the process of updating its allocation for the capitalization of overhead costs.

As part of this study, we are meeting with company management and functional area leaders to:

- Understand the nature and magnitude of functions within the company that support capital projects.
- Understand the regulatory issues that will impact adoption and regulatory approval of a methodology going forward.
- Understand any implications to capital charges with the implementation of IFRS

General Definition of Capitalized Overhead Costs

- Overheads capitalized represents a reasonable and appropriate amount of costs that are directly linked to capital activity (new assets acquired or constructed), but due to the onerous nature of capturing these costs they are not directly assigned to capital costs.
- There must be an established causal link or association of these costs with capital activity.
- These overhead costs are distinguished from those that are directly charged to capital.

Capitalized overhead costs can be described as:

i) Non-Project Specific Capital Support

This includes formulating, evaluating, initiating, designing, approvals and implementing capital additions.

This is captured in capital overhead because:

- Impractical to capture cost directly to specific capital projects
- Function relates to many capital projects rather than specific or identified ones

For example – approval of capital expenditure.

ii) Direct Oversight of activities directly related to capital projects

These costs include the direct supervision, administration, cost control and reporting that are in direct support of capital projects.

For example – supervision of construction departments.

iii) Support Functions and Infrastructure

This category covers the support functions and infrastructure networks that enable departments that are directly involved in performing capital work.

For example – Human Resources, Facilities, IT

For this area – would need to determine a causal link – i.e. would the workload of this function be materially reduced if Terasen ceased to undertake capital projects?

Appendix D – Accounting and Regulatory Guidance

In this Appendix, we provide references to a variety of Canadian and US sources of guidance on the capitalization of overhead costs. This listing is not comprehensive, but does capture the key sources that are likely to be of interest or relevance to Terasen Gas.

A. Canadian Guidance

1. British Columbia Utilities Commission (BCUC)

While the BCUC does not publish an accounting procedures handbook with further guidance for utilities, they recognize Canadian GAAP when assessing overhead costs allocated to capital.

2. Alberta Utilities Commission (AUC) Rule 026 Rule Regarding Regulatory Account Procedures Pertaining to the Implementation of the International Financial Reporting Standards

Section 6(2) of Rule 026 provides guidance related to Specific Regulatory Accounting Items relating to Property Plant & Equipment as follows:

> "(b) Capitalization/Non-Capitalization of Costs: General and Administrative Overhead (IAS 16.16 and 16.19(d))
>
> Utilities shall adhere to the IFRS requirements for capitalization of costs that are not directly attributable to an asset. Any financial difference that arises as a result of the adoption of the IFRS requirements is to be identified in a Utility's First IFRS-Compliant GRA/GTA, and the Utility shall also propose in that rate application the method for settling the difference. In addition, the Utility will file a copy of its updated capitalization policy as a part of its First IFRS-Compliant GRA/GTA.
>
> (f) Capitalization/Non-Capitalization of Costs: Pre-Operating Costs (IAS 16.19, 16.20 (a) and 16.20(b))
>
> Utilities shall adhere to the IFRS requirements regarding the treatment of pre-operating costs. Any financial difference that arises as a result of the adoption of the IFRS requirements is to be identified in a Utility's First IFRS-Compliant GRA/GTA. The Utility shall propose in that rate application the method for settling the difference. In addition, the Utility shall file a copy of its updated capitalization policy as a part of its First IFRS-Compliant GRA/GTA.

(g) Capitalization/Non-Capitalization of Costs: Training Costs (IAS 16.19 (c))

Utilities shall adhere to the IFRS requirements regarding the capitalization of training costs. Any financial difference that arises as a result of the adoption of the IFRS requirements is to be identified in a Utility's First IFRS-Compliant GRA/GTA. The Utility will propose in that rate application the method for settling the difference. In addition, the utility will file a copy of its updated capitalization policy as a part of its First IFRS-Compliant GRA/GTA."

3. Ontario Energy Board's Accounting Procedures Handbook for Electric Distribution Utilities

Article 410 of the Ontario Energy Board Accounting Procedures Handbook states:

"Property, Plant and Equipment should be recorded at cost, which includes the purchase price and other acquisition costs such as: option costs when an option is exercised, brokers' commissions, installation costs including architectural, design and engineering fees, legal fees, survey costs, site preparation costs, freight charges, transportation insurance costs, duties, testing and preparation charges."[1]

Further guidance is provided by Article 230, Definitions and Instructions, No. 20. This document defines the components of construction cost as follows:

"the cost of construction properly included in the electric plant accounts shall include where applicable, the cost of labour; materials and supplies; transportation; work done by others for the utility; injuries and damages incurred in construction work; privileges and permits; special machinery services; allowance for funds used during construction; and such portion of general engineering, administrative salaries and expenses, insurance, taxes, and other similar items as may be properly included in construction costs."[2]

[1] *Ontario Energy Board, Accounting Procedures Handbook, Article 410, p. 7.*
[2] *Ontario Energy Board, Accounting Procedures Handbook, Article 230, p. 5.*

4. Ontario Energy Board's Uniform System of Accounts for Class A Gas Utilities

According to the Ontario Energy Board's Uniform System of Accounts for Class "A" Gas Utilities, Appendix A, Plant Accounting Instructions:

> "Overhead Charged to Construction: includes engineering, supervision, administrative salaries and expenses, construction engineering and supervision, legal expenses, taxes and other similar items. The assignment of overhead costs to particular jobs or units shall be on the basis of a reasonable allocation of actual costs. The records supporting the entries for overhead charged to construction costs shall be maintained so as to show the total amount for each element of overhead for the year and the basis of allocation."

5. CICA Handbook Section 3061 Property, Plant and Equipment ("PP&E")

This Section of the Handbook of the Canadian Institute of Chartered Accountants ("CICA") discusses measurement of PP&E. Section 3061.16 indicates that PP&E should be recorded at cost. Cost is defined in Section 3061.05 as "the amount of consideration given up to acquire, construct, develop or better an item of PP&E and includes all costs directly attributable to the acquisition, construction, development or betterment of the asset".

When an asset is constructed or developed over time, Section 3061.20 indicates that "The cost of an item of property, plant and equipment includes direct construction or development costs (such as materials and labour), and overhead costs *directly attributable* to the construction or development activity." [Emphasis ours]

The Handbook does not define the term "directly attributable"; however, this term is used throughout the handbook in various sections with reference to cost allocations.

The accounting standard does not go into further details on how the overhead costs should be identified or the actual determination of an overhead rate.

6. CICA Handbook Accounting guideline AcG-16 Oil and Gas Accounting – Full Cost

This accounting guideline applies to the application of the full cost method of accounting for oil and gas exploration, development and production activities. While this guideline is not specifically relevant to the capitalization of costs to PP&E, it does discuss the concept of overhead allocation and the capitalization of such costs. The guideline does not recommend or discourage the use of the full cost method of accounting.

Paragraph 7 of the guideline indicates that internal costs capitalized should be limited to those costs that can be "directly identified with the acquisition, exploration and development activities undertaken by the enterprise for its own account, and should not include any costs related to production (lifting costs), general corporate overhead, or similar activities". The guideline further states that capitalized costs include the "portion of overhead or general and administrative costs that can be directly related to, and is necessary to, the exploration and development activity".

7. CICA Handbook section 3031 Inventories

Paragraph 3031.10 states that the "cost of inventories shall comprise all costs of purchase, costs of conversion and other costs incurred in bringing the inventories to their present location and condition".

Paragraph 3031.12 states that "the costs of conversion of inventories include costs directly related to the units of production, such as direct labour. They also include a systematic allocation of fixed and variable production overheads that are incurred in converting materials into finished goods. Fixed production overheads are those indirect costs of production that remain relatively constant regardless of the volume of production, such as depreciation and maintenance of factory buildings and equipment, and the cost of factory management and administration. Variable production overheads are those indirect costs of production that vary directly, or nearly directly, with the volume of production, such as indirect materials and indirect labour."

Paragraph 3031.13 states that "the allocation of fixed production overheads to the costs of conversion is based on the normal capacity of the production facilities. Normal capacity is the production expected to be achieved on average over a number of periods or seasons under normal circumstances, taking into account the loss of capacity resulting from planned maintenance. The actual level of production may be used if it approximates normal capacity. The amount of fixed overhead allocated to each unit of production is not increased as a consequence of low production or idle plant. Unallocated overheads are recognized as an expense in the period in which they are incurred. In periods of abnormally high production, the amount of fixed overhead allocated to each unit of production is decreased so that inventories are not measured above cost. Variable production overheads are allocated to each unit of production on the basis of the actual use of the production facilities."

8. REALpac Accounting Practices Handbook

The Real Property Association of Canada ("REALpac") has published a manual to provide practical and professional interpretations of accounting principles as they relate to Canadian real estate investment and development companies.

REALpac recommends that general and administrative costs directly attributable to construction of a property should be capitalized as a cost of the project. The section describes general and administrative costs to include the following:

- Salaries and benefits of officers of company;
- Travel and automotive costs;
- Audit and legal fees;
- Occupancy costs;
- Stationery;
- Office expenses,;
- Directors' fees;
- Insurance;
- Computer facility costs;
- Subscriptions;
- Capital and business taxes and;
- Donations.

General and administrative costs that cannot be identified with a specific project or projects should not be allocated as a capitalized cost. REALpac gives the example of corporate stewardship costs as a cost that would not be capitalized.

If general and administrative costs (that qualify for capitalization) relate to a number of construction projects, then REALpac recommends that they be allocated to the projects using judgment and well supported methodology. REALpac advises that a time basis would be the most appropriate basis for allocation in most cases. The allocation method should be used on a consistent basis.

B International Guidance

1. International Financial Reporting Standards - General

As a result of recent initiatives by the Accounting Standards Board of Canada ("AcSB"), entities such as Terasen Gas will be required to report under International Financial Reporting Standards ("IFRS") by 2011. IFRS is more restrictive than current accounting standards for regulated utilities with respect to the capitalization of overhead costs.

At this point, there is still some uncertainty regarding the details of the application of IFRS to regulated Canadian utilities. IFRS and Canadian standards may evolve in the years leading up to 2011 and Canadian utility regulators have not yet addressed the issue of transition. The year 2011 is also beyond the horizon of this study's analysis.

Terasen has considered IFRS guidance in the development of this study's estimates of capitalized overhead costs for TGI and TGVI.

2. IAS 16 Property, Plant and Equipment

The guidance under IAS 16 from the International Accounting Standards Board (IASB) prescribes the accounting treatment for property, plant and equipment so that users of the financial statements can discern information about an entity's investment in its property, plant and equipment and the changes in such investment. The principal issues in accounting for property, plant and equipment are the recognition of the assets, the determination of their carrying amounts and the depreciation charges and impairment losses to be recognized in relation to them. Among other guidance, the standard states that:

> "The cost of an item of property, plant and equipment comprises:
>
> (a) its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates.
>
> (b) any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.
>
> (c) the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period."

C. US Guidance

1. FAS 67 – Accounting for Costs and Initial Rental Operations of Real Estate Projects

The guidance under FAS 67 from the Financial Accounting Standards Board (FASB) states that:

> "Indirect project costs that relate to several projects shall be capitalized and allocated to the projects to which the costs relate. Indirect costs that do not clearly relate to projects under development or construction, including general and administrative expenses, shall be charged to expense as incurred." (FAS 67 para 7.)

2. Uniform System of Accounts – Federal Energy Regulatory Commission

Under the Uniform System of Accounts prescribed for public utilities and licensees subject to provisions of the Federal Power Act, capital overhead is defined as:

"Overhead Construction Costs"

A. All overhead construction costs, such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by others than the accounting utility, law expenses, insurance, injuries and damages, relief and pensions, taxes and interest, shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto, to the end that each job or unit shall bear its equitable proportion of such costs and that the entire cost of the unit, both direct and overhead, shall be deducted from the plant accounts at the time the property is retired.

B. As far as practicable, the determination of payroll charges included in construction overheads shall be based on time card distributions thereof. Where this procedure is impractical, special studies shall be made periodically of the time of supervisory employees devoted to construction activities to the end that only such overhead costs as have a definite relation to construction shall be capitalized. The addition to direct construction costs of arbitrary percentages or amounts to cover assumed overhead costs is not permitted.

C. For Major utilities, the records supporting the entries for overhead construction costs shall be so kept as to show the total amount of each overhead for each year, the nature and amount of overhead expenditure charged to each construction work order and to each electric plant account, and the bases of distribution of such costs.

D. Summary

All of this guidance has a common theme. Overhead that can be directly attributed to the construction project should be capitalized as part of the cost of the project. Limited guidance is given to determine which items of overhead would be considered to be "directly attributed" to a project. It seems clear that each entity must review its overhead expenses by type and determine if the cost is necessary to perform the construction project and if so, a portion of the cost should be capitalized. A reasonable basis of allocation must be determined. No guidance is given on allocation methods.

No single regulatory guideline, statement, or source exists that is universally accepted by industries and regulators as the definitive statement, definition, or standard that prescribes what types of overhead costs should be considered for capitalization. However, this topic has been the subject of discussion and comment among regulators and a body of evidence exists on the topic and a number endorse a common principle: that any assignment of indirect costs to a capital project should be done based upon some reasonable causal link or association with the capital activity. Any definition or standard that TGI and TGVI adopts should apply this basic principle.

Appendix E – References

The following table details the research KPMG conducted to review regulatory guidance and practices in other Canadian utilities.

Utility	Commission	Year	Reference/Source	Order / Decision
TGVI	BCUC	2004	Application for Approval of 2003 Actual Revenue Surplus, Forecast 2005 Royalty Adjusted Cost of Gas, Amortization of the Gas Cost Variance Account Balance and 2005 Customer Rates	G-113-04
TGI	BCUC	2009	Approval of Revenue Requirements and Delivery Rates Application	G-191-08
TGI	BCUC	2004	Approval of 2005 Revenue Requirements and Delivery Rates	G-112-04
TGI	BCUC	2004	Approval of 2004 Revenue Requirements and Delivery Rates	G-80-03
BC Gas	BCUC	1997	1998 to 2002 PBR Application Volume 1, Section F	
BC Gas	BCUC	1997	Settlement Agreement	G-85-97
TGI	BCUC	2003	2003 Revenue Requirement - Section 6 Accounting Issues Write up : Page E-13 Table - Section H - Tab 9, Page 2.2	
TGI	BCUC	2003	Section 6 - Accounting Issues Section 6.1 - Overhead Capitalized (2005)	G-7-03
TGI	BCUC	2003	Settlement Agreement for 2004–2007 Multi-Year Performance-Based Rate Plan Page 8, Appendix A	G-51-03
TGI	BCUC	2007	Approval of 2 year extension of the Settlement (G-51-03) for 2008 and 2009	G-33-07
BCTC	BCUC	2007	BCTC 2007 Revenue Requirement application with Capital Overhead Study	G-139-06 G-145-06
BCTC	BCUC	2008	BCTC 2009/2010 Revenue Requirement with updated Cap Overhead methodology information	G-105-08
BCTC	BCUC	2008	BCUC Negotiated Settlement to BCTC including section on Capital Overhead	
BC Hydro	BCUC	2008	BCH F09/10 Rev Req	
BC Hydro	BCUC	2006	BCH F07/08 Rev Req	

Utility	Commission	Year	Reference/Source	Order / Decision
Ottawa Hydro	OEB	2007	Application by Hydro Ottawa Limited for an Order or Orders approving just and reasonable rates and other service charges for the distribution of electricity, effective May 1, 2008. Issue 3.4	EB-2007-0713
ENMAX	AUC	2006	ENMAX Power Corporation 2005-2006 Distribution Tariff	2006-002
ENMAX	AUC	2006	ENMAX Power Corporation 2006 TFO Tariff	2006-079
ATCO	AUC	2005	ATCO Electric 2005-2007 General Tariff Application	
ATCO	AUC	2003	ATCO Electric 2003-2004 General Tariff Application	2003-071
PUC Distribution	OEB	2007	Application by PUC Distribution Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2008.	EB-2007-0931
Hydro One	OEB	2005	In the matter of an application by Hydro one networks inc. For electricity distribution rates 2006 Section 4.5	RP-2005-0020 EB-2005-0378
Hydro One	OEB	2007	Application by Hydro One Networks Inc. for an order or orders approving or fixing just and reasonable rates and other charges for the distribution of electricity commencing May 1, 2008.	EB-2007-0681
Pacific Northern Gas	BCUC	2009	2009 Revenue Requirements Application	G-39-09
EPCOR	AUC	2004	EPCOR Distribution - 2004 DT Part B 2004 Final Distribution Tariff	2004-067
EPCOR	AUC	2006	EPCOR Energy Inc. & EPCOR Energy Alberta Inc. - 2005-2006 Regulated Rate Tariff Non-Energy Charge	2006-055
AltaGas	AUC	2006	AltaGas Utilities Inc. 2005/06 GRA Phase 1 2nd Compliance Filing + Errata	2006-117
AltaGas	AUC	2007	AltaGas Utilities Inc. 2007 GRA Phase I	2007-094
Hydro One	OEB	2005	RJ Rudden Overhead Capitalization Study	RP-2005-0020 EB-2005-0378

KPMG

Terasen Gas Inc.

Shared Services Cost Allocation Review

June 11, 2009

Table of Contents

1.0 Summary of Findings

Terasen Gas Inc. (TGI) retained KPMG to perform an independent review of its shared services cost allocation methodology and the reasonability of the costs of the shared services provided to Terasen Gas Vancouver Island Inc. (TGVI) and Terasen Gas Whistler Inc. (TGW) by TGI in preparation of its 2010/11 Revenue Rate Application (RRA).

In conducting this review KPMG verified that the services provided by TGI to TGVI and TGW are operationally necessary, the methodology used to allocate costs is reasonable, and the costs allocated are reasonable as compared to market alternatives.

KPMG assessed the reasonability of the methodology and the costs allocated to TGVI and TGW against the criteria in section 4.2 of this report. In completing the examination of the shared services cost allocation methodology and resulting costs, KPMG found the following:

Reasonability of the Organizational Structure

- TGI, TGVI and TGW operate under a shared management structure, where leadership resides in TGI;
- It is common in the utility industry to have affiliates provide services to each other for a number of reasons such as sharing overhead costs, sharing of specific expertise, and obtaining economies of scale; and
- KPMG finds this structure to be reasonable.

Necessity of the Services

- There are Service Level Agreements (SLAs) between each of the operating entities which are currently being updated. KPMG completed its review based on the existing 2004 SLAs but took into consideration pending changes in this review. KPMG did not have access to the completed 2009 SLAs prior to completing this review; however in discussions with management we understand that the impact of any changes will not be significant;
- KPMG confirmed that services provided by TGI to TGVI and TGW are not duplicated in TGVI and TGW or by any other source;
- All business, Distribution and Gas Supply and Transmission services as listed in the cost allocation model are commonly found in gas distribution companies;
- Distribution and Gas Supply and Transmission services are allocated in the shared services model. Inclusion of these services in a shared services model is a relatively unique arrangement resulting from the shared management structure and geographical proximity of TGI, TGVI and TGW; and
- KPMG finds that the shared services are all operationally necessary for TGVI and TGW.

Reasonability of the Methodology

- KPMG finds the cost allocation methodology to be reasonable, with the following exception:
    - While the British Columbia Utilities Commission (BCUC) has approved the use of customers as an allocation driver in TGI's 2004 cost allocation model (Order G-112-04), in certain cases we believe that using the number of customers as a driver to allocate costs is not the most related driver. In those cases, TGI should consider using an alternative driver, such as a financial composite driver as those services are more closely tied to the financial activity of TGI than the number of customers. A financial composite driver uses a combination of financial information to derive a percentage to allocate costs. KPMG reviewed two financial composite drivers including:
        - The Massachusetts Model: This model takes an average of revenue, payroll, and the net book value of capital assets and inventory to calculate the allocation percentage. This is a commonly used model in the North American utility industry. Applying the Massachusetts model to those services in question would result in a 2.5% increase ($1,543,462) in the allocation amount to TGVI and a 0.10% increase ($61,187) to TGW; and
        - A comparable Canadian utility financial composite: This model takes an average of revenue, total assets, and capital expenditures to calculate the allocation percentage. It is a variation of the Massachusetts Model that is common in the North American Utility industry. Applying this model to those services in question would result in a 2.19% increase ($1,354,397) in the allocation amount to TGVI and a 0.12% increase ($73,916) to TGW.

      Of the two financial composite drivers reviewed, the comparable Canadian utility financial composite driver is more suitable for TGI since it does not take into account payroll. Payroll would skew results as many employees that work on TGVI and TGW reside in TGI.
- KPMG notes that TGI has not documented its methodology approach outside of the model itself; formal written documentation would assist TGI in applying the methodology consistently year over year. KPMG suggests in the future that TGI consider formally documenting the methodology.

Reasonability of the Allocated Costs

- KPMG finds that it would not be more cost effective for TGVI and TGW to provide these shared services internally;
- KPMG did not evaluate the shared services in terms of having them provided by an external source; however KPMG notes that many of these shared services are not commonly outsourced as they are of strategic value to the business or are integral core businesses. These services would be impractical to outsource or valuable business insight may be lost (i.e. President & CEO, Distribution, Gas Supply and Transmission); and
- KPMG finds the costs allocated to TGVI and TGW from TGI to be reasonable with the following comment:

- KPMG compared TGI's rent costs to publicly available market information, and was not able to locate a comparable facility. However the research KPMG did conduct in the Greater Vancouver area indicates that TGI's rent overhead costs may be above market rates.
- Rent costs used in the model are driven by the underlying real estate value; there are a number of factors that influence the relatively higher value of the TGI facilities including the:
  - Relatively new age of the building;
  - Building fixtures and the extent to which the building is customized to meet TGI's uses;
  - Building location; and
  - Availability of parking on-site.
- The factors above result in the inherently higher value of TGI's facility when compared with available market information. TGI has obtained the opinion of a professional real estate broker who has validated the commercial rate of return used in TGI's calculation of rent costs.
- If TGI were to apply the average market rental rate determined in KPMG's limited research the effect would be approximately 2.6% less being allocated in the model resulting in $165,342 less to TGVI and $4,385 less to TGW.
- While KPMG has been able to narrow the gap between the costs in TGI's model and the available market information, KPMG believes further analysis would be required and an expert opinion received from a professional real estate evaluator. KPMG recommends that TGI continue to obtain regular appraisal of their facilities to validate both the value of the facility and the commercial rate of return used in the model. Documentation of such a review could be made available for evidence to support future inquiries and rate applications to ensure these values remain current.

Benefit to the Ratepayer

- Ratepayers benefit from TGI providing shared services to TGVI and TGW which results in economies of scale by having a single management and support structure, avoiding the duplication of work and allowing customers to benefit from the efficiencies realized. TGVI and TGW also benefit from the depth of expertise which is possible given the shared services structure. Ratepayers therefore benefit from enhanced efficiency.

2.0 Purpose of Report

TGI retained KPMG to perform an independent review of the shared services cost allocation methodology and the reasonability of the costs of the shared services provided to TGVI and TGW by TGI in preparation for the 2010/11 RRA.

KPMG conducted the review of the 2010/11 cost allocation model using 2009 budget figures as 2010/11 budget figures were not yet available. The budget has been reviewed and approved by Terasen Gas' Executive Leadership Team and is used as an input to the Earnings Sharing for the Annual Review with the BCUC.

2.1 Report Structure

The structure of this report is as follows:

Table 2.1a – Report Structure

Section	Description
1.0: Summary of Findings	Includes the summary of KPMG's findings.
2.0: Purpose of Report	Outlines the structure of the report and provides a brief explanation of each section.
3.0: Background	Provides an overview of the cost allocation methodology including the current organizational structure.
4.0: Approach and Methodology	Provides an explanation of KPMG's approach to reviewing TGI's shared services cost allocation methodology and resulting allocated costs including the assumptions and criteria against which KPMG performed its analysis.
5.0: KPMG Research	Provides a summary of the publicly available information KPMG used to perform its analysis of the 2010/11 allocation model and determine its findings.

2.2 Scope Limitations

KPMG's assessment of the shared services cost allocation methodology and related costs involved relying on data and information provided to KPMG by TGI. The data provided by TGI was analyzed by KPMG in carrying out the assessment of the necessity of the services, the reasonability of the allocation methodology and the reasonability of the resulting costs. KPMG has considered the reasonableness of the information provided by TGI however KPMG did not conduct an audit. KPMG has assumed the completeness, accuracy and fair presentation of the information, data or advice provided by TGI. TGI maintains responsibility for the accuracy and completeness of the data and information associated with the shared services cost allocation methodology.

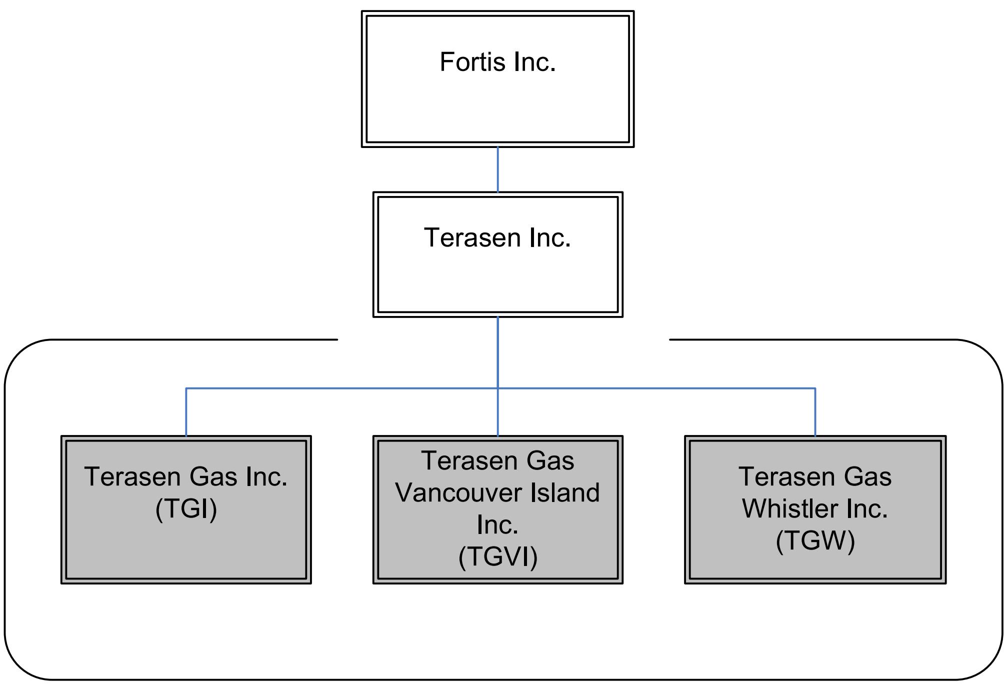
3.0 Background

TGI utilizes a cost allocation model to attribute a portion of its shared services operating costs to TGVI and TGW, both regulated affiliate utility companies.

3.1 Organizational Structure

While TI owns TGI, TGVI and TGW, TGI has operating responsibility for TGVI and TGW. The President & CEO and Vice President (VP) of TGI are also the President & CEO and VP's for TGVI and TGW. The following organization chart illustrates TGI's relationships to regulated and affiliate companies.

Figure 3.1 – Organization Chart



3.2 Shared Services

TGI provides shared services to TGVI and TGW that enable both companies to harness benefits from economies of scale by having a single management and support structure. The services that are provided are outlined in the respective service level agreements. The shared services to TGVI and TGW include services in the following business areas:

Table 3.2 – Shared Services Description

Department	Description
President & CEO's Office	• Overall governance and strategic direction • Overall communications with internal and external parties
Distribution	• Policy direction and oversight of services related to key operational areas • General management and oversight of services • Management of the daily gas distribution operations
HR & Operations Governance	• Human resource policy and management activities • Operational governance activities • Overseeing compliance with standards and regulation
Marketing	• Managing relations with customer groups and stakeholders • Managing customer accounts • Internal and external communications
Business & IT Services	• Managing IT applications and infrastructure • Facilities and Business Services management • Materials and Meter Management Services
Gas Supply & Transmission	• Managing programs relating to gas transmission operations • Developing and Maintaining a comprehensive Integrity Management Plan
Finance & Regulatory Affairs	• Accounting and reporting • Compliance and regulatory activities

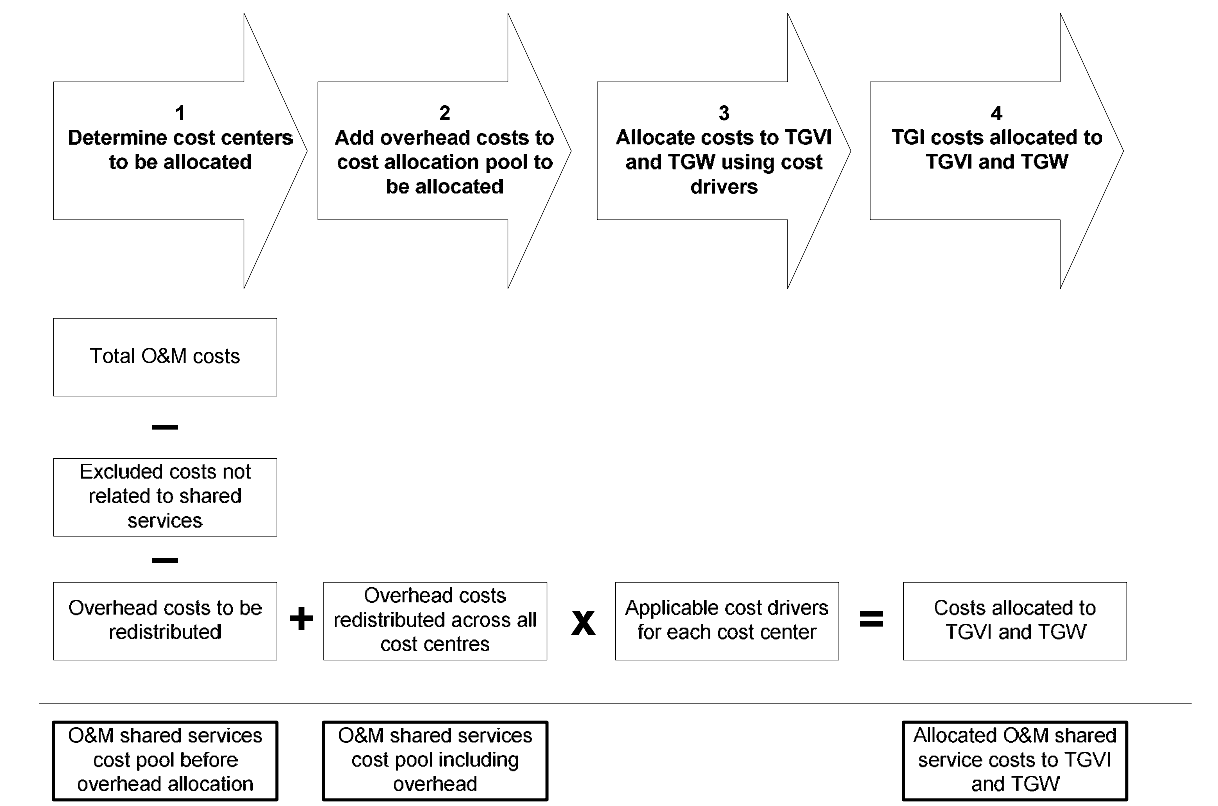
3.3 TGI Cost Allocation Model

Operations and maintenance (O&M) costs for shared services allocated from TGI to TGVI and TGW are calculated at the cost center level. Costs relating to shared services are accumulated into cost pools in each cost center. These costs also include an overhead costs which are distributed across all departments.

These cost pools are then allocated to TGVI and TGW using a specific cost driver. TGI and TGVI also receive a number of corporate shared services from TI. Costs for these services are allocated directly to TGI and TGVI using another shared services cost allocation model, and are not considered in this review.

The following provides a high level summary of how costs are allocated from TGI to TGVI and TGW.

Figure 3.3 – TGI Cost Allocation Model



The shared services cost allocation methodology and model are reviewed on an annual basis, typically in alignment with the budgeting process. Costs allocated are reviewed for budgeting purposes and trued up at year end.

3.4 TGI Costs

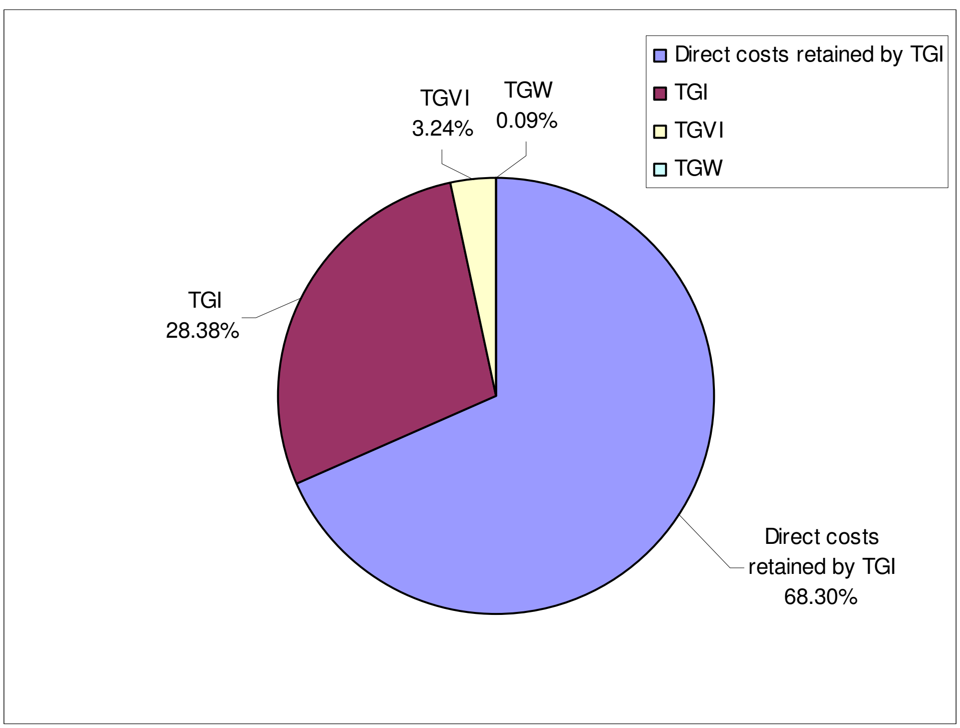
3.4.1 Overview

Budgeted costs allocated from TGI to TGVI and TGW include three components: labour, non-labour and overhead costs. The budget has been reviewed and approved by Terasen Gas' Executive Leadership Team and is used as an input to the Earnings Sharing for the Annual Review with the BCUC. The budgeted costs for 2010/11 will be reviewed as part of TGI's upcoming RRA.

A total of seven departments containing 126 cost centers make up the total shared services cost pool to be allocated between TGI, TGVI and TGW. The total cost pool for allocation is $61,561,380, of which $55,109,372, $6,283,451 and $168,557 are allocated to TGI, TGVI, and TGW respectively.

The following graphic shows the total operating costs for TGI and represents as a percentage those portions that are allocated as shared services to TGI, TGVI, and TGW.

Figure 3.4.1a – Percentage of TGI Costs Allocated



The following table details the FTEs associated with the costs allocated by service and shows the split between labour, non-labour and overhead cost components. The costs included in this table represent the pool of costs to be allocated to TGVI and TGW.

Table 3.4.1b – Labour and Non-labour Costs Allocated

Service	Company	% Allocated	Cost Allocated	FTE	Labour	Non-Labour	Overhead
President & CEO's Office	TGI	89.56%	$ 1,213,684	1.79	$ 626,486	$ 560,398	$ 26,800
	TGVI	10.18%	$ 137,891	0.01	$ 71,177	$ 63,669	$ 3,045
	TGW	0.26%	$ 3,575	0.20	$ 1,845	$ 1,651	$ 79
	Total	100.00%	$ 1,355,150	2.00	$ 699,509	$ 625,717	$ 29,924
Distribution	TGI	84.75%	$ 8,758,409	96.73	$ 6,957,502	$ 465,785	$ 1,335,122
	TGVI	14.87%	$ 1,536,722	0.48	$ 1,218,763	$ 65,213	$ 252,746
	TGW	0.39%	$ 39,838	18.54	$ 31,595	$ 1,691	$ 6,552
	Total	100.00%	$ 10,334,969	115.75	$ 8,207,860	$ 532,688	$ 1,594,421
HR & Operations Governance	TGI	91.71%	$ 8,692,805	71.78	$ 6,004,576	$ 1,645,671	$ 1,042,558
	TGVI	8.09%	$ 766,503	0.16	$ 521,392	$ 152,048	$ 93,063
	TGW	0.20%	$ 18,886	6.41	$ 12,762	$ 3,778	$ 2,346
	Total	100.00%	$ 9,478,195	78.35	$ 6,538,730	$ 1,801,497	$ 1,137,968
Marketing	TGI	89.48%	$ 7,531,589	62.55	$ 5,514,699	$ 1,124,212	$ 892,678
	TGVI	10.16%	$ 855,086	0.23	$ 626,037	$ 127,698	$ 101,351
	TGW	0.36%	$ 30,364	7.10	$ 22,279	$ 4,710	$ 3,375
	Total	100.00%	$ 8,417,041	69.88	$ 6,163,016	$ 1,256,621	$ 997,404
Business & IT Services	TGI	90.80%	$ 20,063,640	177.75	$13,544,391	$ 4,053,756	$ 2,465,493
	TGVI	8.97%	$ 1,981,853	0.52	$ 1,337,041	$ 364,525	$ 280,287
	TGW	0.23%	$ 49,830	20.23	$ 33,693	$ 9,000	$ 7,137
	Total	100.00%	$ 22,095,321	198.50	$14,915,124	$ 4,427,280	$ 2,752,917
Gas Supply & Transmission	TGI	89.56%	$ 1,477,591	16.12	$ 1,047,392	$ 204,605	$ 225,594
	TGVI	10.18%	$ 167,875	0.05	$ 118,998	$ 23,246	$ 25,631
	TGW	0.26%	$ 4,352	1.83	$ 3,085	$ 603	$ 664
	Total	100.00%	$ 1,649,817	18.00	$ 1,169,475	$ 228,453	$ 251,889
Finance & Regulatory Affairs	TGI	89.56%	$ 7,371,654	57.32	$ 6,016,191	$ 546,809	$ 808,654
	TGVI	10.18%	$ 837,521	0.17	$ 683,522	$ 62,125	$ 91,874
	TGW	0.26%	$ 21,712	6.51	$ 17,719	$ 1,611	$ 2,382
	Total	100.00%	$ 8,230,887	64.00	$ 6,717,432	$ 610,545	$ 902,910

3.4.2 Labour Costs

The labour costs include the following types of Full Time Equivalents (FTE):

- Management & Exempt (M&E) employees
- Canadian Office and Professional Employees (COPE) Union Local 378 employees
- International Brotherhood of Electrical Workers (IBEW) Union Local 213 employees

The labour costs include the following cost components:

- Base salary
- Bonus
- Employee benefits

3.4.3 Non-Labour Costs

The non-labour costs include the following key components:

- Travel
- Employee expenses
- Company vehicles
- Supplies
- Membership fees (excluding WEI/CGA membership fees included in overhead costs)
- Employee training
- Consulting services
- Legal services
- IT support services
- Administration

3.4.4 Overhead Costs

Overhead costs are allocated to TGVI and TGW for shared services provided by TGI. Overhead costs include the following components:

- Rent
- IT Services (ITS)
- Membership Fees
- Medium Term Compensation
- Other Post Employment Benefits (OPEB)

An overhead rate per FTE is calculated and applied to each relevant FTE in each cost center. These costs become a part of the cost pool along with labour and non-labour costs that are allocated to TGVI and TGW.

3.5 Cost Drivers

Once labour, non-labour and overhead costs are accumulated in the cost pools of each cost center, the amounts are then allocated from TGI to TGVI and TGW using a cost driver. The driver TGI uses to allocate costs depends on the type of service being provided. Management determines the most relevant cost driver for each cost center based on the key driver of cost.

The following cost drivers are used to allocate overhead costs to individual cost centers:

Table 3.5a – Overhead Cost Drivers

Drivers	Rent	IT Services	Membership Fees *	Medium Term Compensation	OPEB
Employees	X	X	X		X
M&E Employee			X	X	

** Different membership fees use different drivers*

One cost driver is selected for each cost center; therefore multiple drivers may be used in each department.

The following cost drivers are used within each department to allocate costs:

Table 3.5b – Cost Drivers

Drivers	President & CEO	Distribution	Human Resources & Operations Governance	Marketing	Business & Information Technology Services	Gas Supply & Transmission	Finance & Regulatory Affairs
Customers	X	X	X	X	X	X	X
Employees			X		X		
Management Estimate of Time		X	X	X	X		

3.5.1 Customer Driver

The customer cost driver allocates costs based on the percentage of customers receiving service from TGI, TGVI and TGW.

3.5.2 Employee Driver

The employee cost driver allocates costs based on the number of FTEs in TGI, TGVI and TGW respectively.

3.5.3 Management Estimate of Time

Some costs are allocated using management's estimate of time as a driver. Management followed a consistent methodology to estimate the percentage of time spent on providing shared services (i.e. if all employee time in a specific cost centre is spent on TGVI and TGW activities, management will allocate the cost to only TGVI and TGW). The cost allocated by management estimate of time is then added to the cost center cost pool and subsequently allocated to TGVI and TGW using the relevant driver for that cost center.

4.0 Approach and Methodology

4.1 Approach

KPMG's approach to reviewing TGI's shared services cost allocation methodology involved assessing the necessity of the services provided, the reasonability of the allocation methodology, the reasonability of the costs allocated to TGVI and TGW, and the benefit to rate payers of those affiliates.

KPMG's assessment is founded on a detailed understanding and analysis of the work performed by TGI and the services received by TGVI and TGW. KPMG's review of TGI's cost allocation methodology involved the following:

- Holding discussions with TGI finance management and staff;
- Reviewing policies, procedures and other relevant organizational documentation (such as SLAs, organizational charts, compensation and procurement policies, Codes of Conduct, COPE union agreement);
- Reviewing historical regulatory submissions and cost allocation models;
- Reviewing the cost allocation model;
- Validating the accuracy of the data in the model against internal financial management reports (generated from SAP);
- Conducting market research;
- Conducting analysis; and
- Producing this report containing our findings.

To perform the analysis KPMG consulted publicly available information as set out in section 5.0 of this report.

4.2 Methodology and Criteria

KPMG acknowledges the interest that regulators of utilities in Canada have shown in cost allocation methodologies and the resulting costs to ensure they are reasonable. KPMG applies a set of criteria to assess each service that is reflective of the examination regulators have used to make informed decisions. The review criteria are described in the following groups: Services, Allocation Methodology, Costs, and Benefits.

<u>Services</u>

In assessing the reasonableness of services provided by TGI to TGVI and TGW, KPMG applied the following criteria:

Table 4.2a – Services Review Criteria

Review Criteria	Description
Operationally Necessary	Confirm that the service is necessary to operate a gas utility distribution business.
Redundancy	Confirm that the services provided to the receiving entity are not already provided internally by that entity or provided to that entity by another party.
Services Level Agreement (SLA)	Confirm that a SLA exists for the services provided by TGI to the receiving entity.

<u>Allocation Methodology</u>

In assessing the reasonableness of the allocation methodology for attributing the costs from TGI to TGVI and TGW, KPMG applied the following criteria:

Table 4.2b – Allocation Methodology Review Criteria

Review Criteria	Description
Regulatory Precedence	The cost allocation methodology has been tested and approved (i.e. an acceptance of reasonability has been previously established) through regulatory reviews of TGI or other regulated utilities.
Reflective of Service or Investment	The allocation methodology is reflective of the work required to perform the service for TGVI/TGW or reflective of the investment value in TGVI/TGW (i.e. time, assets, and revenue).
Supportable Methodology	The allocation approach is supported by a defined and documented methodology, model, and other supporting documentation. The allocation driver is also linked to an SLA that is updated and reviewed on a consistent basis.
Cost Effective	The allocation driver is calculated and maintained from readily available information resulting in minimal time and expense.
Stable Over Time	The allocation methodology can accommodate changes to the size of the allocation driver from test period to test period and is scaleable given changes in the amount of cost and types of services being allocated.
Objective Results	The use of the allocation driver results in an objective allocation amount that is reasonable for a company of that size for the services being rendered.

Costs

In assessing the reasonableness of the forecast costs for the services provided by TGI to TGVI and TGW, KPMG applied the following criteria:

Table 4.2c – Cost Review Criteria

Review Criteria	Description
Supportable Cost	Independent research conducted supports the reasonableness of the cost for the services provided.
Internal Provision of Service Alternative	Independent research conducted confirms that internal TGVI/TGW provision of the service would not result in a lower cost.
Outsourcing / Third Party Alternative	Independent research conducted confirms that an outsourcing or third party alternative to provide the service would not result in a more reasonable cost.

Benefits

In assessing the reasonableness of the allocation KPMG also considered if there are benefits that arise from having shared services provided by TGI to TGVI and TGW.

5.0 KPMG Research

To determine the reasonability of the shared services provided by TGI to TGVI and TGW as budgeted in 2009, KPMG gathered publicly available information from which to perform its comparative analysis. KPMG found this body of research to be sufficient in determining and supporting the reasonability of the allocation methodology and the resulting costs.

KPMG's research focused on the nature of the shared services, the cost allocation methodology, and the costs of these services.

5.1 Service Research

KPMG assessed the reasonableness of the nature of shared services provided by TGI by comparing them to other similar gas utility companies and KPMG's knowledge of the utility industry.

5.2 Cost Allocation Methodology Research

KPMG's assessment involved comparing the shared services cost allocation methodology used by TGI to methodologies used by other similar utility companies. KPMG also reviewed relevant regulatory applications and decisions for precedence which could be used to assess TGI's shared services cost allocation methodology. This assessment also involved assessing the cost drivers used in the methodology.

5.3 Cost Research

KPMG's detailed review of the costs allocated in the model included:

- **Labour costs** – KPMG assessed the reasonableness of labour costs for Management and Exempt (M&E) employees against TGI's internal compensation policy, salary bands and market rates for similar positions. KPMG conducted a more detailed review of executive labour costs by individual against market rates for reasonableness. KPMG did not review the labour costs related to union positions in detail as these agreements are negotiated and hence are assumed to represent market rates.
- **Non-labour costs** – KPMG assessed the reasonableness of non-labour costs at a high level by reviewing the nature and amount of costs given the size of the cost center, the scope of services, KPMG's knowledge of the utility industry, and comparable market information.
- **Overhead costs** – KPMG assessed the reasonableness of overhead costs at a high level by reviewing the nature and amount of overhead costs given the size of the company, KPMG's knowledge of the utility industry, and comparable market information.

5.4 Summary of Public Information Reviewed

The following list highlights the key research components and how KPMG used it to determine its findings:

Table 5.4 – Research Sources

Source	Description
• System for Electronic Documentation and Analysis Retrieval (SEDAR) Company Profiles • Confidential Sources	President & CEO and executives' compensation for similar sized public companies as TGI.
• Monster 2009 Salary Center • Payscale Salary Survey Reports April 2009 • Hays 2009 Salary Guides • KPMG internal knowledge from client contacts and experience	Compensation information for positions similar to those of TGVI/TGW and for the allocated services provided by TGI; used for compensation comparisons and findings related to internal service provision by TGI.
• Honda Canada • Toyota Canada • VW Canada	Car lease rates for monthly vehicle expenses.
• Commercial Listing Service (CLS) Link Real Estate Board of Greater Vancouver • The Canadian Real Estate Association (CREA)	Market rental rates for office space
• Being the Best: Insights from Leading Finance Functions • KPMG internal knowledge from client contacts and experience	Trends towards outsourcing corporate shared services functions and the cost of outsourcing services.
• Independent Evaluation of Enbridge Gas Distribution Inc.'s Regulatory Corporate Cost Allocation Methodology, Meyers Norris Penny, 2005 • BC Hydro, Revenue Requirements Application, 2004/05, 2007/08, and 2009/10 • Pacific Northern Gas, Revenue Requirements Application to the BC Utilities Commissions – 2008 and 2009 • EPCOR, Corporate Services Review, Bearing Point, 2005 • Union Gas, Cost Allocation Methodology Review, Price Waterhouse Cooper, 2005 • Union Gas, EB-2005-0520 - 2007 Rates • AltaGas Utilities Inc, 2008/09 Cost Allocation Review, KPMG, 2008	Regulatory filings and decisions to determine regulatory precedence regarding allocation drivers and compensation-related approvals.

5.5 Summary of TGI Information Reviewed

The following list highlights the key TGI information sources and how KPMG used it to determine its findings:

Table 5.5 – TGI Information Sources

Source	Description
• TGI Code of Conduct • TGI Code of Business Conduct	Codes of conduct governing relations and activity of TGI.
• Internal testing of the 2009 TGI to TGVI and TGW cost allocation model	Testing performed by TGI finance management of the 2009 cost allocation model.
• Terasen Gas Compensation Overview	Overview of TGI's compensation packages for M&E, COPE and IBEW employees
• TGI Procurement Policy	TGI's policy for acquisition of materials, equipment, and services.
• COPE Union Local 378 Collective Agreement	Collective agreement between COPE Local 378 employees and TGI.

THIS AMENDING AGREEMENT is made effective January 1, 2010 (the "Effective Date").

BETWEEN:

TERASEN GAS (VANCOUVER ISLAND) INC.
16705 Fraser Highway
Surrey, British Columbia
V4N 0E8

(hereinafter referred to as "TGVI")

OF THE FIRST PART

AND:

TERASEN GAS INC.
16705 Fraser Highway
Surrey, British Columbia
V4N 0E8

(hereinafter referred to as "TGI")

OF THE SECOND PART

WHEREAS:

A. TGVI and TGI entered into an agreement dated as of January 1, 2004 (the "Agreement"); and

B. The parties are now desirous of amending the Agreement on the following terms and conditions.

NOW THEREFORE, in consideration of the mutual promises herein and other good and valuable consideration (the receipt and sufficiency of which is hereby acknowledged), the parties hereby covenant and agree as follows:

1. In this Amending Agreement, capitalized words and expressions used shall have the same meanings as are respectively assigned to them in the Agreement.

2. Schedule "A" - Description of Services shall be deleted in its entirety and replaced with the Schedule "A" attached to this Amending Agreement.

3. Schedule "B" - Pricing shall be deleted in its entirety and replaced with the Schedule "B" attached to this Amending Agreement.

4. This Amending Agreement shall be read together with the Agreement as modified.

5. This Amending Agreement shall be governed by and construed in accordance with the laws of the Province of British Columbia and the parties agree to attorn to the jurisdiction of the courts of British Columbia.

6. Words importing the singular include the plural and vice versa; words importing the masculine gender include the feminine and neuter genders; and words importing persons include individuals, sole proprietors, corporations, partnerships and unincorporated associations.

7. This Amending Agreement may be executed in counterparts with the same effect as if all parties had signed the same document. All counterparts will be construed together and will constitute one agreement.

8. All unamended terms and conditions shall remain in full force and effect.

IN WITNESS WHEREOF, the parties hereto have executed this Amending Agreement on June 8, 2009, effective the Effective Date.

TERASEN GAS (VANCOUVER ISLAND) INC.

By: ______________________
Scott A. Thomson

Title: VP, Regulatory Affairs & CFO

TERASEN GAS INC.

By: ______________________

Title: R.L. (Randy) Jespersen
President & CEO

Schedule A
Services

On a shared basis, the personnel from the following departmental units of TGI will provide services to TGVI:

(1) **President's Office.** The role and function of the President of TGI is to provide:

(a) governance and liaisons to direct development and implementation of strategic, operational and capital plans;

(b) governance assurance that controls are in place to ensure the Company's are safeguarded and optimized in the best interests of shareholders, customers and other stakeholders;

(c) alignment and communication of the vision and direction to employees and other stakeholders;

(d) executive level succession planning and development to prepare and maintain exceptional leadership; and

(e) act as the principal spokesperson in maintaining close communication with government and the public.

(2) **Finance and Regulatory Affairs.** The role and function of the Finance and Regulatory Affairs department is to provide the following services:

(a) policy direction and oversight of services related to key financial areas including Strategic Planning, Regulatory Affairs, management and financial reporting, and the capital management office;

(b) oversee the understanding, communication and adherence to accounting policies procedures and practices;

(c) lead financial elements of regulatory processes;

(d) establish and execute the process for managing and facilitating the prioritization of all capital expenditures in the TGI companies through the Capital Management Office;

(e) provide high-level policy, strategic and technical advice & expertise to the company's Executive leadership Team regarding regulatory initiatives and issues as well as the regulatory implications of corporate objectives, strategies and business initiatives and projects taking into consideration emerging regulatory developments and market trends;

(f) ensures adequate and appropriate regulatory constructs and mechanisms are put in place and maintained for all separate legal entities under the Gas Utility Segment of Terasen, taking into consideration the Company's objectives and strategies and market realities;

(g) acts as the Company's focal point of contact with the British Columbia Utilities Commission and ensures the company is fulfilling its obligations regarding governance of Regulatory Orders from the BCUC and Government (Utilities Commission Act);

(h) ensures adequate and appropriate Tariffs and Rates are in place in consideration of the Company's objectives and strategies, market realities, and the approved regulatory constructs and mechanisms;

(i) responsible for the development and execution of corporate regulatory strategy and holds the primary responsibility for the development and maintenance of superior relationships with key interveners, regulatory bodies, market participants and customer representatives;

(j) development of TGI/TGVI financial accounting policies and procedures;

(k) reviewing and maintaining the code of general ledger accounts;

(l) accounting for and validation of all financial statement elements including revenues, cost of gas, deferral accounts, financing costs, bank accounts, the accounting for continuing services and the billing of inter-company transactions;

(m) monthly reporting, variance analysis and year-end forecasting;

(n) external audit coordination and the preparation of non-consolidated financial statements;

(o) annual and multi-year budget processes;

(p) performance measurement and cost analysis;

(q) asset and plant accounting;

(r) the accounts payable group is responsible for ensuring vendors are paid accurately and in a timely manner; and

(s) provide administrative support for corporate credit card program.

(3) **Human Resources and Operations Governance**. This department is focused on providing HR and Operational Governance services to support human resource,

governance and related business needs of the operations of the Terasen group of companies. The functional areas and the services they provide are:

(a) advice and guidance to employees and line managers on human resources management activities such as performance management, disability management, recruiting, succession planning and employee development;

(b) labour relations advice and guidance including negotiating collective agreements, contract administration and application, grievance and arbitration handling and union relations;

(c) processing activities related to costing time, pay, benefits and pension;

(d) records management and reporting;

(e) recruitment and staffing;

(f) policy direction and oversight of services related to key operational areas including governance of Engineering, Occupational Health & Safety, and the Environment, in addition to Emergency Planning and Public Safety;

(g) implementation of maintenance of management systems that control and support emergency planning, security and public safety activities to ensure compliance with applicable laws, company policy and industry codes of practice;

(h) ensuring emergency response plans are maintained, updated and tested on a regular basis;

(i) working with governmental and non-governmental agencies to develop and coordinate emergency response protocols;

(j) coordinating and implementing a public safety awareness program and standards to ensure an appropriate level of public safety communication and program delivery to meet "duty of care" and "duty to warn" due diligence;

(k) delivering trades training services to key operations groups within the utility to maintain skill competencies and ensure compliance with laws, policies and industry codes;

(l) coordination and delivery of non-trades training to maintain core competencies and management & leadership skills;

(m) maintenance of employee training records and competency records;

(n) corporate governance of management systems controlling environmental affairs, employee occupational health & safety, corporate security, public safety awareness, emergency preparedness and the design, construction and operation of the gas pipeline system;

(o) monitoring and reporting of compliance with all applicable laws, company policies and industry codes of practice;

(p) advice and direction to operations groups in support of their accountability to manage specific Environment, Health & Safety and Emergency Preparedness risks;

(q) managing a common standards framework to ensure environmental compliance, a safe working environment for employees and consistent, efficient application of standards;

(r) ensure that the workforce meets Workers Compensation Board legislative requirements; and

(s) uphold customer and public expectations regarding environmental due diligence and habitat preservation.

(4) **Gas Supply and Transmission ("GS&T").** GS&T provides policy direction and oversight services in addition to business performance management related to key operational areas. The GS&T department is responsible for:

(a) maintaining regulatory relationships regarding ongoing Transmission asset management, and managing Transmission safety and pipeline integrity programs;

(b) developing and maintaining a comprehensive Integrity management Plan for the transmission operating plant assets.

(5) **Business and Information Technology Services.** This Division provides business services, information technology application and infrastructure management services which enable the operating areas of the company to provide the delivery of utility services. The Division's focus is company-wide and broad in scope.

(a) policy direction and oversight of services related to key support areas including Business services which is comprised of Facilities services and Purchasing;

(b) management and oversight of services related to information technology application and infrastructure management services;

(c) procurement for materials and services for projects, operations, facilities and IT;

(d) Facilities Management Services has responsibility for all Terasen Offices and Musters throughout the service territory. It provides space management, facilities maintenance and office services;

(e) Application Management Services manages the overall data and application architecture and provides application design, delivery and ongoing support services including technology consulting;

(f) IT Infrastructure Management plans, forecasts, and designs for future infrastructure capacity requirements and develops and directs the implementation of new technology;

(g) IT Infrastructure Management ensures the availability, integrity and security of critical enterprise infrastructure, including: Wide Area Network (WAN), distributed applications/systems, desktop and mobile computer devices, and outsource management;

(h) coordinating the development of security standards and programs to protect Terasen facilities and assets;

(i) management and oversight of services related to project planning and design, system capacity planning, system integrity, corrosion control, property services, facility records and geographical information system mapping;

(j) provides risk-based integrity management services related to operating plant and surrounding natural hazards, principally focused on material defect, corrosion, geotechnical and hydro-technical risks;

(k) responsible for project management and professional services to execute capital projects;

(l) responsible for operation and maintenance of systems providing cathodic protection to operating plant;

(m) responsible for the planning of lowest cost system improvements for the gas Distribution and Transmission systems, as well as hydraulic scenario analysis for operational enquiries and project development;

(n) responsible for managing all land rights and land tenure issues including property taxation, acquisition and disposal, leases, right of way agreements, and for supporting environmental reviews and First Nations negotiations;

(o) responsible for completing new mains and service construction drawings and as-built mapping, as well as detailed design drawings for engineering projects as required by the Distribution and Transmission Asset Management;

(p) responsible for final data integrity checking of field drawings prior to data entry in the Geographic Information System;

(q) responsible for developing and maintaining the Geographic Information Systems (GIS), and maintaining a subset of records for Distribution and Transmission facilities;

(r) Responsible for providing Location Records information for underground facilities, as requested through BC One Call;

(s) policy direction and oversight of services related to key operational areas including Measurement, Shops, Inventory and Trucking;

(t) responsible for supporting the maintenance and security of all pipeline rights of way; this includes third party crossing permits & inspections, sub-division approvals, vegetation management, public awareness and encroachment removal;

(u) the Measurement Group is responsible for managing the measurement device fleet which includes, but is not limited to, the procurement, the inspection, compliance sampling, sealing and repair of meters and measurement devices; and

(v) responsible for ensuring that materials, critical system components and services are manufactured, tested for fitness of use and distributed to operating and support groups.

(6) **Distribution.** The role and function of the Distribution business unit is to provide the following services:

(a) policy direction and oversight of services related to key operational areas including Distribution operations and maintenance, Emergency Management Services, Account Services and Fieldwork, Distribution Operations Support;

(b) general management and oversight of services are focused on delivering a safe, reliable and cost-effective gas distribution system for residential, commercial and industrial customers; and

(c) regional managers and front line field Operations and Install managers who are responsible for day-to-day operations in specific geographic areas.

(7) **Marketing**. The primary responsibilities of Marketing are to manage relations with all customer groups and stakeholders; to sell company services to customers; to manage customer accounts, to produce energy use and account growth forecasts; and to manage TGI's internal and external communications requirements. Marketing provides an organizational focus in the management of these responsibilities and in the delivery of marketing services. Marketing services provided through TGI to TGVI on a shared service basis fall into the following service areas:

(a) responsible for providing overall policy direction and oversight of services relating to the marketing function, including overseeing the development and implementation of marketing initiatives and programs;

(b) provides overall policy direction and oversight of services relating to all markets;

(c) develops marketing communications, supports the communications collateral requirements of Builder/Developer and Commercial/Industrial Account Managers, develops and executes marketing events and undertakes trade relations activities that support sales and marketing efforts;

(d) deals with; customer escalations from the call centres, via email or written correspondence and through outside organizations (BCUC, MLA offices, BBB);

(e) creates messaging for customer education and communication on the topics of rate changes, natural gas prices, competition with alternative fuels, billing issues, customer connection policies and regulatory changes (e.g., gas cost increase, rate design changes);

(f) provides market research activities focus on customer research (e.g., end-use studies), customer satisfaction, safety, and attitudes and opinions around Company initiatives;

(g) oversees both the Main Extension test, and the Company's service line policies;

(h) evaluates existing offerings including feasibility studies to determine if they represent the right mix of customer service and core market cost recovery and the design, negotiation and submission of new an amended services to the British Columbia Utilities Commission;

(i) develops customer energy use and customer additions forecasts;

(j) provides analysis and decision support to internal and external customers on longer-term supply/demand and pricing issues, and performs portfolio modeling; Examples of internal customers would include various departments such as Gas Supply, Finance, Regulatory, System Planning and Operations. Examples of external customers would include various municipalities and other government agencies as well as individual (mainly commercial) customers;

(k) provides overall policy direction and oversight of services relating to TGVI's community, government and aboriginal relations requirements;

(l) provides internal and external communications services for the Company, including corporate branding, employee communication and media relations;

(m) provides customer service, general inquiry response, and order processing for construction orders including service installations, alterations and abandonments through the Customer Contact Centre;

(n) provides Customer Care policy direction and oversees outsourced service provider activities, including Customer Care Services Contract, Billing, and Credit & Collections administration;

(o) provides Technical Support for customers and sales and marketing functions;

(p) provides Energy Efficiency and Conservation services including program development, administration, delivery, monitoring and reporting; and

(q) develops both Regional Resource Plans and Integrated Resource Plans for all companies.

Schedule B
Pricing

Cost Allocation Drivers

Department	Allocation Method
President	# of Customers
Finance & Regulatory	# of Customers
Human Resources & Operations Governance	# of Customers # of Employees Specific Allocation %
Gas Supply & Transmission	# of Customers
Business & IT Services	# of Customers # of Employees Specific Allocation %
Distribution	# of Customers Specific Allocation %
Marketing	# of Customers Specific Allocation %

Note: Does not include Timesheet (or Direct Charge) allocations.

THIS AGREEMENT is made effective January 1, 2010 (the "Effective Date").

BETWEEN:

TERASEN GAS (WHISTLER) INC.
16705 Fraser Highway,
Surrey, British Columbia
V4N 0E8

("**TGW**")

AND:

TERASEN GAS INC.
16705 Fraser Highway,
Surrey, British Columbia
V4N 0E8

("**TGI**")

WHEREAS

A. TGW is the owner and operator of propane distribution facilities, which are being converted to natural gas distribution facilities throughout 2009, in British Columbia serving the community of Whistler (the "Facilities"); and

B. TGW wishes to retain TGI to provide certain administrative and management services to it in respect to the ownership and common management of the operation of its transmission pipeline and distribution business on the terms and conditions set out herein.

WITNESSES that, in consideration of the covenants and agreements herein contained, the parties covenant and agree as follows:

PART 1
INTERPRETATION

1.1 Definitions

In and for the purpose of this Agreement

(a) "**Applicable Laws**" means any and all Laws in force and effect from time to time and applicable to the Facilities and the performance of the Services hereunder;

(b) "**Force Majeure**" has the meaning assigned to such term in Section 9.1;

(c) "**Governmental Authority**" means any domestic or foreign, national, federal, provincial, state, municipal or other local government or body and any division, agent, commission, board, or authority of any quasi-governmental or private body exercising any statutory, regulatory, expropriation or taxing authority under the authority of any of the foregoing, and any domestic, foreign, international, judicial, quasi-judicial, arbitration or administrative court, tribunal, commission, board or panel acting under the authority of any of the foregoing;

(d) "**Laws**" means all constitutions, treaties, laws, statutes, codes, ordinances, orders, decrees, rules, regulations and municipal by-laws, whether domestic, foreign or international, any judgements, orders, writs, injunctions, decision, rulings, decrees, and awards of any Governmental Authority, and any published policies or guidelines of any Governmental Authority and including, without limitation, any principles of common law and equity,

(e) "**Person**" includes any individual, corporation, body corporate, partnership, joint venture, association, trust, estate, incorporated or unincorporated association, any government or governmental authority however designated or constituted or any other entity of whatever nature,

(f) "**Services**" means the administrative and management services to be provided to TGW by TGI as more particularly described in Section 2.1.

1.2 Schedules

The following are the schedules attached to, and are incorporated by reference into, this Agreement:

Schedule "A"	Description of Services
Schedule "B"	Pricing

1.3 Interpretation

In and for the purpose of this Agreement

1) this "Agreement" means this agreement as the same may from time to time be modified, supplemented or amended in effect,

2) any reference in this Agreement to a designated "Article", "Section" or other subdivision is to the designated Article, Section or other subdivision of this Agreement,

3) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this Agreement as a whole and not to any particular Article, Section or other subdivision,

4) the headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement,

5) the singular of any term includes the plural, and vice versa, the use of any term is generally applicable to any gender and, where applicable, a corporation, the word "or" is not exclusive and the word "including" is not limiting (whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto), and

6) each word and phrase used herein and not otherwise defined herein, but which has an accepted meaning in the custom and usage of the Western Canadian oil and gas transportation industry, shall have such accepted meaning.

1.4 Governing Law

Subject to Section 9.1, this Agreement will be interpreted and the rights and remedies of the parties hereto will be determined in accordance with the laws of the Province of British Columbia.

PART 2
SERVICES

2.1 Services

TGI hereby agrees to provide to TGW those administrative and management services described in Schedule "A".

2.2 No Obligation to Provide Additional Services

TGI shall not perform, and TGI shall have no obligation to perform, any services on behalf of TGW in respect of the Facilities other than as set out in this Agreement or any similar agreement.

2.3 Consultation with TGW

TGI will consult with TGW as required in connection with the performance of the Services.

2.4 Independent Contractor

Nothing in this Agreement shall be construed to create or constitute a partnership or relationship of joint venture between TGI and TGW. In performing the Services, TGI shall be an independent contractor. TGI employees shall not be considered employees of TGW for any purpose.

2.5 Compliance

In performing the Services, TGI will comply with all Applicable Laws.

PART 3
COMPENSATION

3.1 Compensation for Services

TGW agrees to pay to TGI for the Services the compensation set out in Schedule "B".

3.2 Amendment to Costs

The amounts set out in Schedule "B" may be amended from time to time by agreement between the parties to reflect any material change in the cost of providing the services or in the business operations of TGW.

3.3 Invoicing

TGI will invoice TGW in respect of the Services no later than the 25th day following the end of the month in which such Services are provided or in such other manner as the parties may agree.

3.4 Payment

(a) Except with respect to those portions of an Invoice which are the subject of a bona fide dispute between the parties, invoices shall be payable within thirty (30) days from the date of the invoice.

(b) Any amount to be remitted by TGW to TGI and not remitted on or before the date on which it is due shall thereafter bear interest at an annual rate equal to the prime rate of interest of the Toronto-Dominion Bank (or its successor or permitted assign) (Toronto, Main Branch) plus one percent (1%) calculated daily from the date the amounts become due.

(c) TGI will prepare financial accounting of the actual costs and the allocated costs, and will make adjustments based on additional amount to be paid by TGW or return an overpayment.

(d) Payments due and owing as a result of the accounting will be paid no later then the end of the first quarter of the following year.

3.5 Taxes

Notwithstanding any other provision of this Agreement, the amounts paid or payable by one party to the other in accordance with this Agreement are exclusive of any value added taxes or sales taxes, which are now, or may become during the term of this Agreement, applicable to the provision of the Services. Each party shall pay to the other party any value added taxes or sales tax which one party is obligated to collect from the other at the time such taxes are due and payable.

PART 4
INDEMNIFICATION AND LIMITATION OF LIABILITY

4.1 Indemnity by TGW

Subject to Section 4.4, TGW will indemnify, defend and hold harmless TGI and its directors, officers, employees, agents and contractors, from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, and cost or expense (including reasonable legal fees and disbursements) which they may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with TGI's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of TGI.

4.2 Limitation of Liability of TGI

Neither TGI nor any of its directors, officers, employees, agents or contractors will be liable to TGW for any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, or cost or expense (including reasonable legal fees and disbursements) which TGW may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with TGI's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of TGI.

4.3 Indemnity by TGI

Subject to Section 4.4, TGI will indemnify, defend and hold harmless TGW from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award and cost or expense (including reasonable legal fees and disbursements) which TGW may suffer or incur as a result of any act or omission or error of judgement as a result of which TGI is adjudged to have been guilty of wilful misconduct or gross negligence.

4.4 Consequential Losses

Neither party hereto will be liable to the other, whether based in contract, tort (including negligence and strict liability), under warranty or otherwise for special indirect, incidental or consequential loss or damage whatsoever, including without limitation, loss of use of equipment or facilities and loss of profits or revenues.

PART 5
COVENANTS OF TGW

5.1 Covenants by TGW

TGW covenants and agrees to:

(a) fully co-operate with TGI in respect of all matters contemplated by or within the scope of this Agreement; and

(b) pay on or before the due date thereof all amounts payable by TGW to TGI or any other Person pursuant to or as contemplated by this Agreement.

PART 6
REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of TGI

TGI hereby represents and warrants to TGW as representations and warranties which are true as at the date hereof and which will be true during the term of TGI's appointment hereunder:

(a) TGI is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and TGI has full power and authority to perform its obligations hereunder,

(b) this Agreement constitutes a valid and binding obligation of TGI enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought; and

(c) TGI possesses all of the skills and personnel required to provide the Services.

6.2 Representations and Warranties of TGW

TGW hereby represents and warrants to TGI as representations and warranties which are true as at the date hereof and which will be true during the term of TGI's appointment hereunder

(a) TGW is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and TGW has full power and authority to perform its obligations hereunder; and

(b) this Agreement constitutes a valid and binding obligation of TGW enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought.

PART 7
DURATION, TERMINATION AND DEFAULT

7.1 Effective Date and Term

This Agreement will be effective from January 1, 2010 and will continue until December 31, 2010, unless terminated earlier pursuant to the provisions hereof. Thereafter the Agreement will automatically be renewed for further one (1) year terms subject to Sections 7.2 and 7.3 below.

7.2 Termination

TGI's appointment hereunder may be terminated at any time:

(a) by TGI giving TGW written notice of such termination:

(i) if TGW becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if TGW makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against TGW seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of TGW or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or TGW consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; and

(ii) in the event TGW breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by TGW of written notice thereof from TGI or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from TGI and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of TGI that TGW is in breach is conceded to be correct by TGW or found to be correct by an arbitrator pursuant to Section 8.1;

(b) by TGW giving TGI written notice of such termination:

(i) if TGI becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if TGI makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against TGI seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of TGI or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or TGI consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; and

(ii) in the event TGI breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by TGI of written notice thereof from TGW or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from TGW and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of TGW that TGI is in breach is conceded to be correct by TGI or found to be correct by an arbitrator pursuant to Section 8.1.

7.3 Termination Without Cause

Notwithstanding Section 7.2 above either party may, upon obtaining the other party's written consent, terminate this Agreement without penalty or damages upon giving thirty (30) days written notice.

7.4 Duties Upon Termination

Upon expiry or termination of this Agreement for any reason, TGI will have no further obligations under Article 2 and will promptly deliver to TGW any material documents in the possession of TGI pertaining to the business of TGW.

7.5 Compensation of TGI on Expiry or Termination

Within one (1) month after the expiry or termination of this Agreement, TGW will pay to TGI all amounts owing to TGI hereunder (including any amount owing on account of the fees provided for in Article 3 calculated up to the date of expiry or termination); provided that for the purposes of this Section, the fees provided for in Article 3 which are payable to TGI on a monthly, annual or other periodic basis will be deemed to accrue due and be payable on a daily basis.

PART 8
ARBITRATION

8.1 Arbitration

For purposes of Section 7.2, any dispute between TGI and TGW regarding any allegation that TGW or TGI is in breach of this Agreement, may be submitted to and settled by arbitration in accordance with the provisions of this Section 8.1. Arbitration proceedings may be commenced by the party desiring arbitration giving notice to the other party specifying the matter to be arbitrated and requesting arbitration thereof. Such arbitration will be carried out by a single arbitrator and in accordance with the Rules of Procedure for Commercial Mediation of The Canadian Foundation for Dispute Resolution from time to time in force and effect. If the parties are unable to agree upon an arbitrator within ten (10) days after delivery of such notice, either of them may make application to court for appointment of an arbitrator. In the event of the failure, refusal or inability of an arbitrator to act, or continue to act, a new arbitrator will be appointed, which appointment will be made in the same manner as provided above. The decision of an arbitrator appointed as under this Section 8.1 will be final and binding upon the parties and not subject to appeal. The arbitrator will have the authority to assess the costs of the arbitration against either or both of the parties, provided that each party will bear its own witness and counsel fees. The parties will fully co-operate with the arbitrator and provide all information reasonably requested by the arbitrator. Judgement on the award of the arbitrator may be entered in any court having jurisdiction over the party against which enforcement of the award is being sought. Each party hereby irrevocably submits and consents to the jurisdiction of any such court for the purpose of rendering a judgement of any such award.

PART 9
FORCE MAJEURE

9.1 Force Majeure

In and for the purposes of this Agreement, "Force Majeure" shall mean anyone or more of the following events:

(a) an act of God;

(b) a war, revolution, insurrection, riot, blockade, or any other unlawful act against public order or authority;

(c) a strike, lockout or other industrial disturbance;

(d) a storm, fire, flood, explosion, earthquake or lightning;

(e) a governmental restraint; or

(f) any other event (whether or not of the kind enumerated in 9.1(a) to (e) above) which is not reasonably within the control of the party hereto claiming suspension of its obligations hereunder due to Force Majeure.

9.2 Performance Prevented by Force Majeure

If either party hereto is prevented by Force Majeure from carrying out any of its obligations hereunder, the obligations of such party, insofar as its obligations are affected by Force Majeure, shall be suspended while (but only so long as) Force Majeure continues to prevent the performance of such obligations. Any party prevented from carrying out any obligation by Force Majeure shall promptly give the other party hereto notice of Force Majeure including reasonably full particulars thereof.

9.3 Remedy of Force Majeure

A party claiming suspension of its obligations by reason of Force Majeure shall promptly remedy the cause and effect of Force Majeure described in the notice given pursuant to Section 9.2 insofar as such party is reasonably able so to do, provided that the terms of settlement of any strike, lockout or other industrial disturbance shall be wholly in the discretion of the party hereby claiming suspension of its obligations hereunder by reason thereof; and that such party shall not be required to accede to the demands of its opponents in any strike, lockout or industrial disturbance solely to remedy promptly Force Majeure thereby constituted.

9.4 Lack of Funds Not Force Majeure

Notwithstanding anything contained in this Article 9, lack of finances shall not be considered Force Majeure nor shall Force Majeure suspend any obligation for the payment of money due hereunder.

PART 10

MISCELLANEOUS

10.1 Notice

Any notice, direction or other communication required or permitted to be given hereunder must be in writing and will be sufficiently given if delivered or sent by facsimile to the party from whom it is intended at the address of such party set out below. Any notice, direction or other communication so given will be deemed to have been given and to have been received on the day of delivery, if delivered, or on the day of sending if sent by facsimile (provided such day of delivery or sending is a Business Day and, if not, then on the first Business Day thereafter). Each party hereto may change its address for notice by notice given in the manner aforesaid.

10.2 Assignment

Neither party hereto may assign this Agreement or any of its rights hereunder without the prior written consent of the other party, such consent not to be unreasonably withheld.

10.3 Amendments

Any amendment or modification of this Agreement must be in writing and signed by the party against which such amendment or modification is sought to be enforced.

10.4 Severability

If any term or condition of this Agreement or the application hereof is determined judicially or otherwise to be invalid or unenforceable, the remainder of this Agreement and the application thereof shall not be affected and shall remain in full force and effect.

10.5 Entire Agreement

This Agreement constitutes the entire agreement between the parties pertaining to the subject matter hereof. There are no representations, warranties, covenants or agreements between the parties in connection with such subject matter except as specifically set forth or referred to in this Agreement.

10.6 Counterparts, Facsimile

This Agreement may be executed by the execution of one or more counterparts of the execution page, which will be taken together and constitute the execution page, and one or more of such counterparts may be delivered by facsimile transmission.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement on June 8, 2009, effective the Effective Date.

TERASEN GAS (WHISTLER) INC.

By: ______________________
Scott A. Thomson

Title: VP, Regulatory Affairs & CFO

TERASEN GAS INC.

By: ______________________

Title: R.L. (Randy) Jespersen
President & CEO

Schedule A
Services

On a shared basis, the personnel from the following departmental units of TGI will provide services to TGW:

(1) **President's Office.** The role and function of the President of TGI is to provide:

(a) governance and liaisons to direct development and implementation of strategic, operational and capital plans;

(b) governance assurance that controls are in place to ensure the Company's are safeguarded and optimized in the best interests of shareholders, customers and other stakeholders;

(c) alignment and communication of the vision and direction to employees and other stakeholders;

(d) executive level succession planning and development to prepare and maintain exceptional leadership; and

(e) act as the principal spokesperson in maintaining close communication with government and the public.

(2) **Finance and Regulatory Affairs**. The role and function of the Finance and Regulatory Affairs department is to provide the following services:

(a) policy direction and oversight of services related to key financial areas including Strategic Planning, Regulatory Affairs, management and financial reporting, and the capital management office;

(b) oversee the understanding, communication and adherence to accounting policies procedures and practices;

(c) lead financial elements of regulatory processes;

(d) establish and execute the process for managing and facilitating the prioritization of all capital expenditures in the TGI companies through the Capital Management Office;

(e) provide high-level policy, strategic and technical advice & expertise to the company's Executive leadership Team regarding regulatory initiatives and issues as well as the regulatory implications of corporate objectives, strategies and business initiatives and projects taking into consideration emerging regulatory developments and market trends

(f) ensures adequate and appropriate regulatory constructs and mechanisms are put in place and maintained for all separate legal entities under the Gas Utility Segment of Terasen, taking into consideration the Company's objectives and strategies and market realities

(g) acts as the Company's focal point of contact with the British Columbia Utilities Commission and ensures the company is fulfilling its obligations regarding governance of Regulatory Orders from the BCUC and Government (Utilities Commission Act);

(h) ensures adequate and appropriate Tariffs and Rates are in place in consideration of the Company's objectives and strategies, market realities, and the approved regulatory constructs and mechanisms

(i) responsible for the development and execution of corporate regulatory strategy and holds the primary responsibility for the development and maintenance of superior relationships with key interveners, regulatory bodies, market participants and customer representatives

(j) development of TGI/TGW financial accounting policies and procedures;

(k) reviewing and maintaining the code of general ledger accounts;

(l) accounting for and validation of all financial statement elements including revenues, cost of gas, deferral accounts, financing costs, bank accounts, the accounting for continuing services and the billing of inter-company transactions;

(m) monthly reporting, variance analysis and year-end forecasting;

(n) external audit coordination and the preparation of non-consolidated financial statements;

(o) annual and multi-year budget processes;

(p) performance measurement and cost analysis; and

(q) asset and plant accounting.

(r) the accounts payable group is responsible for ensuring vendors are paid accurately and in a timely manner.

(s) provide administrative support for corporate credit card program.

(3) **Human Resources and Operations Governance**. This department is focused on providing HR and Operational Governance services to support human resource, governance and related business needs of the operations of the Terasen group of companies. The functional areas and the services they provide are:

(a) advice and guidance to employees and line managers on human resources management activities such as performance management, disability management, recruiting, succession planning and employee development;

(b) labour relations advice and guidance including negotiating collective agreements, contract administration and application, grievance and arbitration handling and union relations;

(c) processing activities related to costing time, pay, benefits and pension;

(d) records management and reporting;

(e) recruitment and staffing.

(f) policy direction and oversight of services related to key operational areas including governance of Engineering, Occupational Health & Safety, and the Environment, in addition to Emergency Planning and Public Safety;

(g) implementation of maintenance of management systems that control and support emergency planning, security and public safety activities to ensure compliance with applicable laws, company policy and industry codes of practice;

(h) ensuring emergency response plans are maintained, updated and tested on a regular basis;

(i) working with governmental and non-governmental agencies to develop and coordinate emergency response protocols;

(j) coordinating and implementing a public safety awareness program and standards to ensure an appropriate level of public safety communication and program delivery to meet "duty of care" and "duty to warn" due diligence;

(k) delivering trades training services to key operations groups within the utility to maintain skill competencies and ensure compliance with laws, policies and industry codes;

(l) coordination and delivery of non-trades training to maintain core competencies and management & leadership skills;

(m) maintenance of employee training records and competency records;

(n) corporate governance of management systems controlling environmental affairs, employee occupational health & safety, corporate security, public safety awareness, emergency preparedness and the design, construction and operation of the gas pipeline system;

(o) monitoring and reporting of compliance with all applicable laws, company policies and industry codes of practice;

(p) advice and direction to operations groups in support of their accountability to manage specific Environment, Health & Safety and Emergency Preparedness risks;

(q) managing a common standards framework to ensure environmental compliance, a safe working environment for employees and consistent, efficient application of standards;

(r) ensure that the workforce meets Workers Compensation Board legislative requirements;

(s) uphold customer and public expectations regarding environmental due diligence and habitat preservation;

(4) **Gas Supply and Transmission ("GS&T")**. GS&T provides policy direction and oversight services in addition to business performance management related to key operational areas. The GST department is responsible for:

(a) maintaining regulatory relationships regarding ongoing Transmission asset management, and managing Transmission safety and pipeline integrity programs;

(b) developing and maintaining a comprehensive Integrity management Plan for the transmission operating plant assets.

(5) **Business and Information Technology Services**. This Division provides business services, information technology application and infrastructure management services which enable the operating areas of the company to provide the delivery of utility services. The Division's focus is company-wide and broad in scope.

(a) policy direction and oversight of services related to key support areas including Business services which is comprised of Facilities services and Purchasing;

(b) management and oversight of services related to information technology application and infrastructure management services;

(c) procurement for materials and services for projects, operations, facilities and IT;

(d) Facilities Management Services has responsibility for all Terasen Offices and Musters throughout the service territory. It provides space management, facilities maintenance and office services;

(e) Application Management Services manages the overall data and application architecture and provides application design, delivery and ongoing support services including technology consulting;

(f) IT Infrastructure Management plans, forecasts, and designs for future infrastructure capacity requirements and develops and directs the implementation of new technology;

(g) IT Infrastructure Management ensures the availability, integrity and security of critical enterprise infrastructure, including: Wide Area Network (WAN), distributed applications/systems, desktop and mobile computer devices, and outsource management;

(h) coordinating the development of security standards and programs to protect Terasen facilities and assets;

(i) management and oversight of services related to project planning and design, system capacity planning, system integrity, corrosion control, property services, facility records and geographical information system mapping;

(j) provides risk-based integrity management services related to operating plant and surrounding natural hazards, principally focused on material defect, corrosion, geotechnical and hydro-technical risks;

(k) responsible for project management and professional services to execute capital projects;

(l) responsible for operation and maintenance of systems providing cathodic protection to operating plant;

(m) responsible for the planning of lowest cost system improvements for the gas Distribution and Transmission systems, as well as hydraulic scenario analysis for operational enquiries and project development;

(n) responsible for managing all land rights and land tenure issues including property taxation, acquisition and disposal, leases, right of way agreements, and for supporting environmental reviews and First Nations negotiations;

(o) responsible for completing new mains and service construction drawings and as-built mapping, as well as detailed design drawings for engineering projects as required by the Distribution and Transmission Asset Management;

(p) responsible for final data integrity checking of field drawings prior to data entry in the Geographic Information System;

(q) responsible for developing and maintaining the Geographic Information Systems (GIS), and maintaining a subset of records for Distribution and Transmission facilities; and

(r) Responsible for providing Location Records information for underground facilities, as requested through BC One Call.

(s) policy direction and oversight of services related to key operational areas including Measurement, Shops, Inventory and Trucking;

(t) responsible for supporting the maintenance and security of all pipeline rights of way; this includes third party crossing permits & inspections, sub-division approvals, vegetation management, public awareness and encroachment removal;

(u) the Measurement Group is responsible for managing the measurement device fleet which includes, but is not limited to, the procurement, the inspection, compliance sampling, sealing and repair of meters and measurement devices

(v) responsible for ensuring that materials, critical system components and services are manufactured, tested for fitness of use and distributed to operating and support groups;

(6) **Distribution.** The role and function of the Distribution business unit is to provide the following services:

(a) policy direction and oversight of services related to key operational areas including Distribution operations and maintenance, Emergency Management Services, Account Services and Fieldwork, Distribution Operations Support;

(b) general management and oversight of services are focused on delivering a safe, reliable and cost-effective gas distribution system for residential, commercial and industrial customers;

(c) regional managers and front line field Operations and Install managers who are responsible for day-to-day operations in specific geographic areas;

(7) **Marketing.** The primary responsibilities of Marketing are to manage relations with all customer groups and stakeholders; to sell company services to customers; to manage customer accounts, to produce energy use and account growth forecasts; and to manage TGI's internal and external communications requirements. Marketing provides an organizational focus in the management of these responsibilities and in the delivery of marketing services.

Marketing services provided through TGI to TGW on a shared service basis fall into the following service areas:

(a) responsible for providing overall policy direction and oversight of services relating to the marketing function, including overseeing the development and implementation of marketing initiatives and programs;

(b) provides overall policy direction and oversight of services relating to all markets including sales functions and customer account management for residential and commercial customers;

(c) develops marketing communications, supports the communications collateral requirements of Builder/Developer and Commercial/Industrial Account Managers, develops and executes marketing events and undertakes trade relations activities that support sales and marketing efforts;

(d) deals with; customer escalations from the call centres, via email or written correspondence and through outside organizations (BCUC, MLA offices, BBB);

(e) creates messaging for customer education and communication on the topics of rate changes, natural gas prices, competition with alternative fuels, billing issues, customer connection policies and regulatory changes (e.g., gas cost increase, rate design changes);

(f) provides market research activities focus on customer research (e.g., end-use studies), customer satisfaction, safety, and attitudes and opinions around Company initiatives;

(g) oversees both the Main Extension test, and the Company's service line policies;

(h) evaluates existing offerings including feasibility studies to determine if they represent the right mix of customer service and core market cost recovery and the design, negotiation and submission of new an amended services to the British Columbia Utilities Commission;

(i) develops customer energy use and customer additions forecasts;

(j) provides analysis and decision support to internal and external customers on longer-term supply/demand and pricing issues, and performs portfolio modelling; Examples of internal customers would include various departments such as Gas Supply, Finance, Regulatory, System Planning and Operations. Examples of external customers would include various municipalities and other government agencies as well as individual (mainly commercial) customers;

(k) provides overall policy direction and oversight of services relating to TGW's community, government and aboriginal relations requirements;

(l) provides internal and external communications services for the Company, including corporate branding, employee communication and media relations;

(m) provides customer service, general inquiry response, and order processing for construction orders including service installations, alterations and abandonments through the Customer Contact Centre;

(n) provides Customer Care policy direction and oversees outsourced service provider activities, including Customer Care Services Contract, Billing, and Credit & Collections administration;

(o) provides Technical Support for customers and sales and marketing functions;

(p) provides Energy Efficiency and Conservation services including program development, administration, delivery, monitoring and reporting;

(q) develops both Regional Resource Plans and Integrated Resource Plans for all companies.

Schedule B
Pricing

Cost Allocation Drivers

Department	Allocation Method
President	# of Customers
Finance & Regulatory	# of Customers
Human Resources & Operations Governance	# of Customers # of Employees Specific Allocation %
Gas Supply & Transmission	# of Customers
Business & IT Services	# of Customers # of Employees Specific Allocation %
Distribution	# of Customers Specific Allocation %
Marketing	# of Customers Specific Allocation %

Note: Does not include Timesheet (or Direct Charge) allocations.

Schedule “A”

Description of Services

Schedule "B"

Pricing

CORPORATE SERVICES

The Corporate Services Review Report by KPMG
was not available at the time of filing.

The Corporate Services Report as well as the
Corporate Services Agreement will be filed as soon as available.

Terasen Gas Inc.

Transfer Pricing Methodology Review

June 12, 2009

Table of Contents

1.0 Summary of Findings

Terasen Gas Inc. (TGI) retained KPMG to perform an independent review of the Transfer Pricing Methodology, which is used to calculate the cost of services provided by TGI to Non Regulated Businesses (NRB). The Transfer Pricing Methodology is a composite of the Terasen's Code of Conduct, the Transfer Pricing Policy and the Transfer Pricing Model, used to charge for services provided. The purpose of this review is to verify that the Transfer Pricing Methodology used by TGI is complete and reasonable.

KPMG conducted the review of the 2010/11 Transfer Pricing Model and resulting costs using 2009 budget figures as 2010/11budget figures were not yet available. Our findings and conclusions are therefore limited accordingly.

KPMG assessed the Transfer Pricing Methodology against the criteria outlined in Section 4.0 of this report. In completing the examination of the Transfer Pricing Methodology KPMG found the following:

Reasonableness and Completeness of the Transfer Pricing Methodology
KPMG assessed the reasonableness of the Transfer Pricing Methodology, which included an assessment against other utilities and regulatory precedence. KPMG finds that TGI's Transfer Pricing Methodology is reasonable.

Code of Conduct - KPMG finds the Code of Conduct complete and in compliance with BCUC's guidelines.

Transfer Pricing Policy - KPMG finds the Transfer Pricing Policy, used by TGI for services provided to NRBs, to be complete, and reflective of the guidelines set out in the Code of Conduct, with the following observations regarding the implementation of the policy:

- As per TGI's Transfer Pricing Policy, the transfer price is determined based on full cost recovery or market rate recovery, whichever is higher. KPMG finds that TGI makes a reasonable effort to ensure their charges reflect a full cost recovery, but Terasen does not assess the cost of the services provided against market. As the charge for services tend to be immaterial (i.e. costs transferred using the Transfer Pricing Methodology represent about 0.3% of total O&M budget), KPMG feels that the time and effort required to determine market rates is not warranted in most cases. However, KPMG suggest that for material amounts, Terasen consider a periodic test against market to ensure Terasen is compliant with their internal policy.
- Although the rates for regulated equipment appear to be reasonable, the Transfer Pricing Policy does not describe how the direct charge for the use of rate regulated equipment is determined. KPMG recommends TGI update the Transfer Pricing Policy to reflect this detail.

Transfer Pricing Model - KPMG assessed the reasonableness and completeness of the calculations in the transfer pricing model and tested them against the guidelines and principles in the Code of Conduct and Transfer Pricing Policy. KPMG found the model calculations to be reasonable, complete, and in line with the Code of Conduct and Transfer Pricing Policy with the following observations:

- The Facilities charge being used in the transfer pricing model needs to be reviewed on a regular basis in order to reflect the actual current cost of the service that is being recovered. KPMG recommends that TGI review this input cost annually and update as needed, or apply an annual inflation rate to the Facilities charge, to ensure the transfer pricing rates are current;
- KPMG recommends that TGI tracks the changes made to input costs, or to the structure of the model itself, including the reason for any changes to ensure that the transfer pricing model is kept current and applied consistently year over year.

2.0 Purpose of Report

TGI retained KPMG to perform an independent review of the Transfer Pricing Methodology for services provided by TGI to NRBs. This report summarizes KPMG's review approach and findings. The following section discusses the structure of the report.

2.1 Report Structure

The structure of this report is as follows:

Section	Description
1.0: Summary of Findings	Provides a summary of KPMG's findings.
2.0: Purpose of Report	Outlines the structure of the report and provides a brief explanation of each section and appendix.
3.0: Background	Provides an overview of the TGI Transfer Pricing Methodology.
4.0: Approach and Methodology	Provides an explanation of KPMG's approach to reviewing TGI's Transfer Pricing Methodology including the assumptions and criteria against which KPMG performed its analysis.
5.0: Research	Provides a summary of the TGI documents and the publicly available information KPMG used to perform its analysis of the Transfer Pricing Policy and determine its findings.
6.0: KPMG Findings	Presents KPMG's findings of the review of TGI's Transfer Pricing Methodology.

The detailed analysis and results are found in the appendices as follows:

Appendix	Description
A: Glossary	Contains a glossary of terms used in this report.

2.2

Scope Limitations

KPMG's assessment of the Transfer Pricing Methodology involved relying on data and information provided to KPMG by TGI. The data provided by TGI was analyzed by KPMG in carrying out the assessment of the completeness and the reasonability of Transfer Pricing Methodology. KPMG has considered the reasonableness of the information provided by TGI however KPMG did not conduct an audit. KPMG has assumed the completeness, accuracy and fair presentation of the information, data or advice provided by TGI. TGI maintains responsibility for the accuracy and completeness of the data and information associated with the Transfer Pricing Methodology.

3.0 Background

TGI utilizes a Transfer Pricing Methodology to recover costs for services provided by TGI to NRB's. The following section provides an explanation of the Transfer Pricing Methodology used by TGI.

3.1 TGI Transfer Pricing Methodology Background

The purpose of the Transfer Pricing Methodology is to ensure that Utility ratepayers are not adversely affected by services provided to NRBs. There are a number of components that make up the Transfer Pricing Methodology: the Code of Conduct, the Transfer Pricing Policy, and the Transfer Pricing Model. The Code of Conduct governs the relationship between TGI and NRBs for the provision of utility resources. The Transfer Pricing Policy provides guidance in determining the cost of services, the type of services available to NRBs, employee issues, and accounting and collections procedures. The accompanying Transfer Pricing Model implements the guidelines outlined in the Code of Conduct and the Transfer Pricing Policy and allows TGI to establish a daily rate for the different types of services provided to NRBs.

TGI's Transfer Pricing Policy was approved by BCUC in 1997 when TGI was still BC Gas Utility Ltd. (BCGUL). The Transfer Pricing Policy was drafted in accordance with the BC Gas Utility Ltd. Code of Conduct, both of which were approved by the BCUC in Letter L-64-1997. TGI reviews the Code of Conduct and the Transfer Pricing Policy on an annual basis to conform to the BCUC Code of Conduct Compliance requirements.

3.2 Transfer Pricing Policy and Model

The following section discusses the types of services available to NRBs, the cost components used to determine a full cost transfer price and a summary of the model that is used to calculate a daily rate for each type of service.

3.2.1 Service Types

TGI's Transfer Pricing model calculates different daily rates depending on the type of services provided to the NRB. The following are the services provided to NRBs:

Table 3.2.1 – Service Types

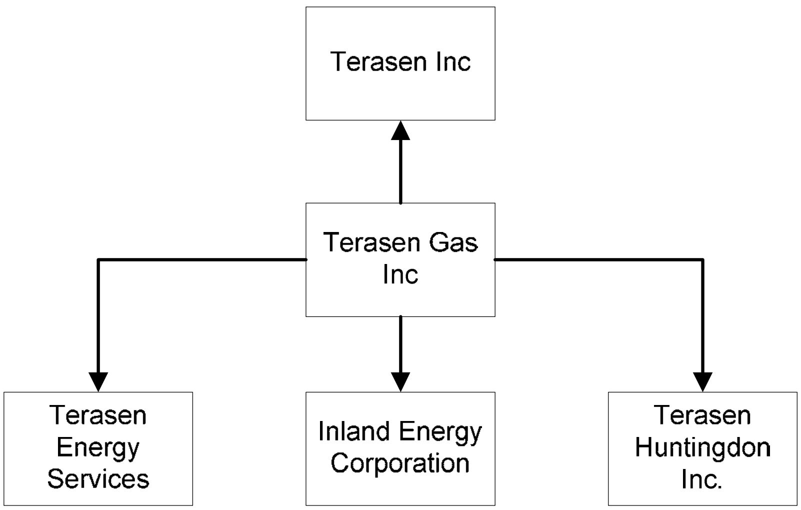
Service Type	Location	Description
Specific Committed Service	On-site	Service is provided on an ongoing basis and supports the regular activities of the NRB. Staff is located at TGI's office, and is contractually committed to provide service to the NRB. The NRB is billed regardless of whether or not the work is actually performed.

Service Type	Location	Description
	Off-site	Service is provided on an ongoing basis and supports the regular activities of the NRB. Staff is located at the NRB work site, and is contractually committed to provide service to the NRB. The NRB is billed regardless of whether or not the work is actually performed.
As Required Service	On-site Short Term	This service cannot typically be budgeted in advance and is charged out at the cost of the actual time incurred to perform the services. Staff is located at TGI and the term of the service provided is for three months or less.
	Off-site Short Term	This service cannot typically be budgeted in advance and is charged out at the cost of the actual time incurred to perform the services. Staff is located at the NRB's work site and the term of the service provided is for three months or less.
	Off-site Extended	This service cannot typically be budgeted in advance and is charged out at the cost of the actual time incurred to perform the services. Staff is located at the NRB's work site and the term of the service provided is for three months or more.
Designated Subsidiary/Affiliate	n/a	Service is provided to a related company that has been approved by the BCUC to receive reduced loadings in the transfer price.

TGI provides services primarily to the following NRBs:

- Terasen Inc.
- Terasen Energy Services
- Inland Energy Corp
- Terasen Huntingdon Inc.

Figure 3.2.1 Transfer of Service to NRBs



3.2.2 Cost Components

The transfer price that is charged to NRBs is developed based on the 1997 Transfer Pricing Policy and includes six major components that are used to determine the full cost transfer price. The proposed 2010/11 methodology remains the same and will continue to use the same six components, only the input costs have changed. KPMG conducted the review of the 2010/11 Transfer Pricing Methodology using 2009 budget figures as inputs to the Transfer Pricing Model as 2010/11budget figures were not yet available. Our findings and conclusions are therefore limited accordingly.

Table 3.2.2a – Cost Components

Cost Component	Description	Driver
Loaded Labour Costs	Labour is included in the transfer price charged to NRBs. The labour rate used is a loaded rate which includes base pay, concessions and benefits. Concessions are added to the labour rate for non-productive time such as vacation, statutory holiday and sick days. Benefits include such items as health, dental, life insurance disability, and WCB.	Hours

Cost Component	Description	Driver
General Overhead	NRBs are charged for overhead that benefit the employees that provide service to the NRBs. This cost component is determined by adding a specific percentage to the loaded labour costs. The percentage added to labour costs is determined by taking the total O&M costs relating to overhead costs divided by total O&M costs.	% of Costs
Supervision	The costs of supervising employees that provide service to NRBs at TGI's office (on-site) are included in the transfer price. The percentage is calculated as the ratio of supervisors to employees in TGI (i.e. ratio is 1 supervisor for 8 employees or 12.5%). This cost component is calculated as a percentage of the loaded labour cost component.	Headcount
Availability Charge	An availability charge is included in the transfer price for As Required services provided by TGI to NRBs. This charge represents the cost for maintaining employees on site ready to provide services to the NRBs and is based on a third party study. This cost component is calculated as a percentage of the loaded labour cost component.	% of Cost
Facilities Charge	The transfer price includes a facilities charge for employees who provide services to NRBs from TGI's office (on-site). The average daily facilities cost per employee is added to the transfer price. The facility charge is separate from the general overhead charge and includes the following items: • Surrey Operations Space Costs • Telephone • Computer Hardware • SAP and Microsoft Licenses • SAP Software • IT Support Services • Office Supplies and Postage • Office Furniture and Equipment Print, Fax and Copy	Per FTE Cost
Equipment	Equipment costs related to services provided by TGI to NRBs are charged directly to the NRBs. The charge is determined based on the average cost of the actual equipment used in the delivery of service (i.e. For vehicles, the charge is the average hourly rate for operating the vehicle as calculated from a pool of total vehicle costs).	Direct Charge

Different cost components are included in the transfer price to make up the full cost recovery charge, depending on the type of service that the NRB is requesting. The following table summarizes the cost components that are included in the transfer price for each service type.

Table 3.2.2b – Cost Components that make up the Transfer Price

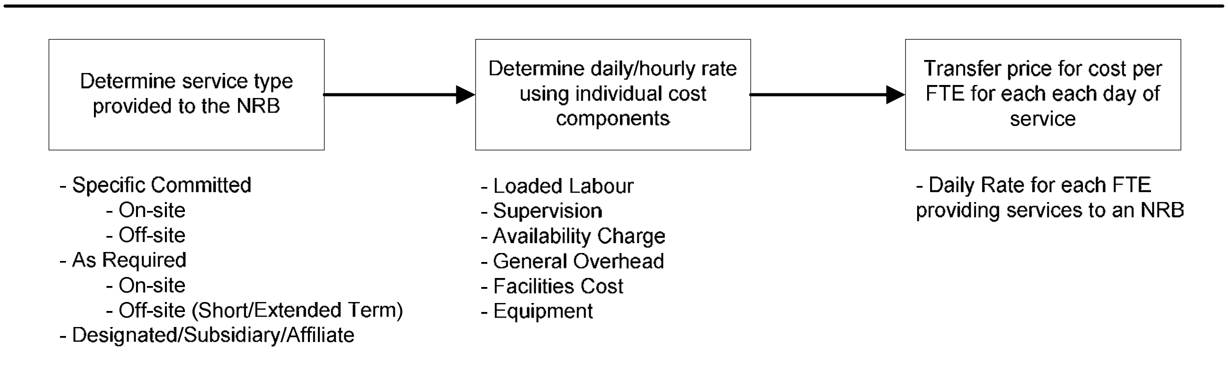
Cost Component	Specific Committed Service		As Required Service			Designated Subsidiary / Affiliate
	Off-Site	On-Site	On-Site Short Term	Off-Site Short Term	Off-Site Extended	
Loaded Labour Cost	X	X	X	X	X	X
General Overhead	X*	X	X	X	X*	X*
Supervision		^	X			^
Availability Charge			X	X	X	
Facilities Charge		X	X	X		
Equipment	^	^	^	^	^	

** Charged ½ of the rate for some service types*
^ Directly charged to NRB

3.2.3 Model Summary

TGI's Transfer Pricing Policy provides the pricing rules and guidelines for determining the full cost of service. The Transfer Pricing Model encapsulates the pricing rules set out in the Transfer Pricing policy and calculates a daily rate for each TGI Full Time Equivalent (FTE) that provides services to the NRB based on the type of service (see table 3.2.1) and the applicable cost components (see section 3.2.2) . The following illustrates how the transfer price daily rate is derived:

Figure 3.2.3 – Transfer Price Model



4.0 Approach and Methodology

As previously noted, KPMG was engaged by TGI to review its Transfer Pricing Methodology with respect to completeness and reasonability. As part of our review KPMG completed a comparison to the approaches taken by utilities in other jurisdictions. KPMG's approach to the TGI Review is founded on:

- An understanding of British Columbia guidelines with respect to Affiliate Codes of Conduct and Transfer Pricing Policies supported by comparisons to utilities in other jurisdictions;
- The assumption that the data provided by TGI accurately represents all cost components related to the transfer of services.

Our work plan incorporated the following steps:

- **Step 1: Review the company's Code of Conduct, Policy and Model.**

KPMG obtained and reviewed all relevant documentation relating to TGI's Transfer Pricing Methodology in order to obtain a thorough understanding of TGI's Transfer Pricing Methodology. A complete list of documents reviewed can be found in section 5.2.

- **Step 2: Document and review regulatory policy guidance.**

KPMG researched the guidance provided by relevant regulatory authorities on the topic of transfer pricing. The objective of this step was to ensure that the approach adopted in TGI's Transfer Pricing Methodology is consistent with a cross-section of current industry standards and practices. A summary of the sources of our research is provided in section 5.1.

- **Step 3: Assess the reasonableness of TGI's Transfer Pricing Methodology.**

KPMG assessed the alignment between TGI's Transfer Pricing Methodology against internal policy, external guidance from regulators and the practices of other Canadian utilities as observed through a review of regulatory filings in various jurisdictions. Additionally, KPMG sought answers to the following questions under the areas of completeness, and reasonableness in assessing TGIs Transfer Pricing Methodology:

Completeness

- Does the Code of Conduct comply with the guidelines set out by BCUC for services provided to NRBs?
- Does the Transfer Pricing Policy comply with the guidelines set out in TGI's Code of Conduct?
- Does the Transfer Pricing Model and resulting calculation of full cost take into account all the guidelines and principles outlined in the Transfer Pricing Policy and the Code of Conduct?

- Are all expenses related to services provided to NRBs included in the Transfer Pricing Policy and related model?
- Is the implementation of the Transfer Pricing Policy documented in the model or an accompanying procedure manual?

Reasonableness

- Do the calculations reasonably represent the costs incurred by TGI to deliver services to NRBs?
- Does the implementation of the Transfer Pricing Methodology reasonably reflect the intent and spirit of the BCUC guidelines, the Code of Conduct and the Transfer Pricing Policy?

To perform the analysis KPMG consulted the information sources as set out in section 5.0 of this report. In addition, to assist in the assessment of the reasonableness of the Transfer Pricing Methodology for attributing the costs from TGI to NRBs, KPMG applied the following criteria:

Table 4.2a – Transfer Pricing Methodology Review Criteria

Review Criteria	Description
Regulatory Precedence	The Transfer Pricing Methodology has been tested and approved (i.e. an acceptance of reasonability has been previously established) through regulatory reviews of TGI or other regulated utilities.
Reflective of Service	The Transfer Pricing Methodology results in a cost that is reflective of the work required to perform the service for the NRBs.
Supportable Methodology	The Transfer Pricing Methodology approach is supported by a defined and documented methodology, model, and other supporting documentation.
Cost Effective	The transfer price is calculated and maintained from readily available information resulting in minimal time and expense.
Stable Over Time	The Transfer Pricing Methodology can accommodate changes to the input variables from test period to test period and is scaleable given changes in the amount of cost and types of services being allocated.
Objective Results	The use of the transfer price results in an objective allocation amount that is reasonable for the services being rendered.

- **Step 4: Prepared report.**

In this step, KPMG prepared this report to summarize our approach and the results of the review.

4.0 Research

KPMG assessed TGI's Transfer Pricing Methodology against internal documents, the BCUC guidelines with respect to transfer pricing, and other gas and electric regulated utilities' Affiliate Code of Conducts and Transfer Pricing Policies.

4.1 Summary of Research

The following table presents the key external research sources and how KPMG used it to determine its findings:

Table 5.1 – Research Sources

Source	Description
British Columbia Utilities Commission, Retail Markets Downstream of the Utility Meter, April 1997	Contains the BCUC guidelines for Transfer Pricing Policies and Codes of Conduct.
British Columbia Utilities Commission, Letter number L-64-97	BCUC's approval of TGI's Draft Code of Conduct and Transfer Pricing Policy.
Ontario Energy Board, Affiliate Relationships Code for Gas Utilities (July 1999)	Sets out the standards and conditions for interaction between gas distributors, transmitters and storage companies that are regulated by the OEB and their respective affiliate.
ATCO Group, Inter-Affiliate Code of Conduct May 22, 2003	Provides an example of the standards and parameters that govern inter-affiliate conduct for regulated entities under the Alberta Utilities Commission (AUC).
ATCO Gas, Accounting Policies and Procedures, General Provision of Services to or from Affiliates	Provides an example of an inter-affiliate transfer pricing policy for a similar gas utility, for a regulated entity under the AUC.
EPCOR Utilities, Code of Conduct and Exemption Application (February 2004)	Provides an example of the standards and parameters that govern inter-affiliate conduct for regulated entities under the AUC.
ENMAX Power Corporation, Inter-Affiliate Code of Conduct (October 2004)	Provides an example of the standards and parameters that govern inter-affiliate conduct for regulated entities under the AUC.

4.2 Summary of TGI Documents Reviewed

KPMG reviewed a number of documents provided by TGI during the assessment of TGI's Transfer Pricing Policy, the list includes:

Table 5.2 – TGI Documents

Source	Description
• 1991 BC Gas Inc. NRB/Utility Separation	The study conducted in 1991 to determine the transfer

Study, December 1991	price TGI BC Gas Inc. should charge to NRB's for utility services.
• 1997 TGI Code of Conduct for Provision of Utility Resources and Services, August 1997	The Code of Conduct governs the relationships between TGI and NRBs for the provision of utility resources and services.
• BC Gas Utility Transfer Pricing Policy for Provision of Utility Resources and Services, August 1997	This policy addresses the pricing of resources and services provided by BC Gas Utility Ltd. to NRBs.
• TGI Transfer Pricing Policy Review, May 2009	Reviews the Transfer Pricing Policy governing transactions between TGI and NRBs updated for 2009 cost assumptions.
• Annual Review of Compliance with the Terasen Gas Inc Code of Conduct and Transfer Pricing Policy (September 26, 2008)	The review is conducted to satisfy the BCUC requirement with regards to Terasen's compliance with their Code of Conduct and Transfer Pricing Policy.

5.0 KPMG Findings

This section presents KPMG's findings of the review of TGI's Transfer Pricing Methodology.

The Transfer Pricing Methodology reviewed meets the criteria established by KPMG and is in accordance with industry standards and practices related to transfer pricing for services provided by a regulated utility to a non-regulated affiliates.

Overall, KPMG finds that the Transfer Pricing Methodology to be fair and reasonable except as noted in the findings.

Findings and Recommendations

Code of Conduct

TGIs Code of Conduct was approved by the BCUC in 1997, Letter L-64-1997. Compliance with the Code of Conduct is subject to an annual review by TGI's internal audit and a third party. The compliance report is filed with the BCUC on an annual basis. KPMG finds the Code of Conduct to be in alignment with BCUC's guidelines as documented in the 2008 Annual Compliance Review.

Transfer Pricing Policy

The Transfer Pricing Policy was written in August 1997 and approved by BCUC by Letter L-64-1997. Compliance with the Transfer Pricing Policy is subject to an annual review by TGI's internal audit and a third party. The compliance report is filed with the BCUC on an annual basis. KPMG found the Transfer Pricing Policy, used by TGI for services provided to NRBs, to be reasonable, complete and in compliance with the TGI Code of Conduct with the following observations:

The use of full cost recovery or market price, whichever is greater, is stated in the TGI Transfer Pricing Policy (section 1) and outlined in BCUCs Transfer Pricing Policy Guidelines (RMDM Guidelines):

> *The accounting costs are transparent and will normally fully recover for all services, including overhead, space, employee benefits, inconvenience, and a profit margin where appropriate. If the service provided by the utility to the related-NRB could also be obtained from an independent supplier, the price paid by the related-NRB to the utility should be no less than the competitive market price and will never be below the incremental cost.*

However, KPMG found no evidence that TGI has any mechanism to compare full recovery costs to market, where appropriate. As the charge for services tend to be immaterial (i.e. costs transferred using the Transfer Pricing Methodology represent about 0.3% of total O&M budget), KPMG feels that the time and effort required to determine market rates is not warranted in most cases. However, KPMG suggest that for material amounts, Terasen consider a periodic test against market to ensure Terasen is compliant with their internal policy.

TGI includes a direct charge for equipment used to provide services to NRBs in the Transfer Price example in Appendix A (see Equipment in 3.2.2 Cost Components). However, the Transfer Pricing Policy does not state how the charge for the equipment is determined. KPMG recommends that TGI document how charges for the use of equipment are determined.

Model

TGI reviewed and updated the electronic version of the Transfer Pricing Model and the cost inputs for 2009. KPMG verified the 2009 costs inputted in to the model from TGI sources, but did not compare them to market. KPMG also tested the method of loading the services with different costs to create a full cost recovery and finds the model to be complete and reasonable.

KPMG tested the excel version of the model and found the model to be free of any material errors. The TGI Transfer Pricing Model is in line with both the current TGI Transfer Pricing Policy and the Code of Conduct, with the following exception:

- The methodology does not have a mechanism to test for market costs as outlined in the Transfer Pricing Policy.

KPMG recommends a 'Change Log' Worksheet be added to the electronic version of the model to track changes and when inputs to the model, or the models structure, have been changed or updated. TGI may want to consider documenting the rational for the inclusion and/or exclusion of costs from the model, either within the model or as a separate document in order to support full transparency and to ensure that the methodology is applied consistently year over year.

KPMG recommends that TGI review the Facilities costs annually and update as needed with actual cost data from SAP to ensure full cost recovery over time, or apply an annual inflation rate to the Facilities charge, to ensure the transfer pricing rates are current.

Table 6.1 - Review Criteria Findings

Review Criteria	Description
Regulatory Precedence	The Code of Conduct and the Transfer Pricing Policy currently in use were approved by BCUC in 1997 in Letter L-64-1997. A similar structure, with regulated utilities providing services to NRB affiliates, is evident in many Canadian utilities. The utility regulators in Alberta and Ontario have set out similar guidelines for Affiliate Codes of Conducts and transfer pricing. Utilities that offer similar services to non regulated affiliates include, the ATCO Group, ENMAX, EPCOR Utilities, and Fortis Alberta.
Reflective of Service	The Transfer Pricing Methodology results in a cost that is reflective of the work required to perform the service for the NRBs.

Review Criteria	Description
Supportable Methodology	The Transfer Pricing Methodology approach is supported by the Code of Conduct, the Transfer Pricing Policy and the Transfer Pricing Model. KPMG notes that TGI has not documented the approach to determining the input costs used in the model. KPMG suggests TGI considers formally documenting the process for identifying the inputs to the model and implement a change log in the model.
Cost Effective	The data needed for the inputs to the transfer price, (base pay, overhead, facilities charges, supervision, and availability), are all readily available from TGI HR and TGI's accounting system (SAP).
Stable Over Time	The model is flexible and can accommodate changes over time, however, the facilities costs inputted into the model need to be updated annually to ensure that the most recent costs are reflected in the transfer pricing model. KPMG recommends that TGI either update the facilities costs annually or increase the transfer price by an inflation factor annually.
Objective Results	The use of the transfer pricing model to calculate full cost results in an objective allocation amount that is reasonable for the specific type of service being rendered.

APPENDIX A: Glossary

Term	Definition
AUC	Alberta Utilities Commission
BCGUL	BC Gas Utility Ltd.
BCUC	British Columbia Utilities Commission – An independent regulatory agency of the British Columbia Provincial Government that operates under and administers the Utilities Commission Act. Its primary responsibility is the regulation of British Columbia's natural gas and electricity utilities.
FTE	Full Time Equivalent – Resource requirement equivalent to one full time employee.
NRB	Non Regulated Businesses – An affiliate of TGI not regulated by the BCUC or a division of TGI offering unregulated products and/or services.
OEB	Ontario Energy Board
RMDM	Retail Markets Downstream of the Utility Meter Guidelines
TGI	Terasen Gas Inc.

Appendix I

RATE BASE INFORMATION

RATE BASE HISTORY

a) Normalized Actual Rate Base Continuity 2003-2008

TERASEN GAS INC.
NORMALIZED ACTUAL RATE BASE CONTINUITY ($000's)
FOR THE YEARS ENDING DECEMBER 31

		2003	2004	2005	2006	2007	2008
1	Gross Plant In Service Opening	2,696,795	2,817,462	2,889,618	3,020,621	3,067,389	3,140,066
2	Additions	110,233	94,208	104,928	112,532	104,688	111,588
3	Retirements	(15,953)	(42,637)	(27,495)	(70,099)	(46,514)	(45,745)
4	Adjustments, Transfers, Recoveries	(635)	6,510	(44)	(2)	3,657	293
5	CPCN's	27,023	14,075	53,614	4,336	10,846	7,848
6	Gross Plant In Service Closing	2,817,462	2,889,618	3,020,621	3,067,389	3,140,066	3,214,050
7							
8	Intangible Plant Opening	837	837	837	837	837	1,614
9	Additions	-	-	-	-	-	-
10	Retirements	-	-	-	-	-	-
11	Adjustments	-	-	-	-	-	-
12	CPCN	-	-	-	-	777	-
13	Intangible Plant Closing	837	837	837	837	1,614	1,614
14							
15	CIAC Opening	(134,289)	(142,889)	(156,262)	(148,612)	(162,075)	(150,600)
16	Additions	(8,660)	(13,373)	(9,006)	(12,839)	(9,270)	(12,279)
17	Retirements	-	-	16,656	(625)	21,471	1,242
18	Adjustments	60	-	-	1	(726)	1
19	CIAC Closing	(142,889)	(156,262)	(148,612)	(162,075)	(150,600)	(161,636)
20							
21	CIAC Accumulated Amortization	32,764	41,338	51,042	44,913	53,394	40,486
22	Amortization	8,132	9,704	10,527	7,856	8,523	6,145
23	Retirements	-	-	(16,656)	625	(21,471)	(1,242)
24	Adjustments	442	-	-	-	40	(8)
25	CIAC Closing Accumulated Amortization	41,338	51,042	44,913	53,394	40,486	45,381
26							
27	Accumulated Depreciation Opening	(492,735)	(550,541)	(598,518)	(655,495)	(670,195)	(711,495)
28	Depreciation	(79,726)	(87,320)	(87,605)	(90,199)	(86,508)	(84,097)
29	Retirements[1]	15,953	42,637	27,495	70,099	45,213	45,745
30	Adjustments, Proceeds, Retirement Costs	5,967	(3,294)	3,133	5,400	(5)	6,361
31	Accumulated Depreciation Closing	(550,541)	(598,518)	(655,495)	(670,195)	(711,495)	(743,486)
32							
33	Opening Net Plant In Service[2]	2,130,395	2,180,282	2,240,331	2,266,600	2,300,196	2,327,919
34	Closing Net Plant In Service	2,166,207	2,186,717	2,262,264	2,289,350	2,320,071	2,355,923
35							
36	Mid Year Net Plant In Service	2,148,301	2,183,500	2,251,298	2,277,975	2,310,133	2,341,921
37	Adjustment to 13-month average	(6,533)	(7,492)	(5,344)	(1,745)	(2,663)	3,208
38	Work in progress, no AFUDC	6,565	4,695	14,510	9,927	7,719	7,062
39		2,148,333	2,180,703	2,260,464	2,286,157	2,315,189	2,352,191
40	Deferred Charges	29,488	23,763	6,274	9,424	(14,754)	(26,223)
41	Cash Working Capital	(14,434)	(16,452)	(15,410)	(21,611)	(23,624)	(25,044)
42	Gas In Storage Working Capital	83,461	112,112	151,056	160,586	142,265	164,419
43	Other Working Capital	6,699	7,424	8,481	10,469	10,563	12,360
44	Other	(4,704)	(1,959)	(2,749)	(2,673)	(3,459)	(3,256)
45							
46	Utility Rate Base	2,248,843	2,305,591	2,408,116	2,442,352	2,426,180	2,474,447

[1], [2]

[1] Retirements not equal to GPIS in 2007 because of land retirement and gain/loss on sale of NGV cylinders

[2] Opening net plant in service not equal to previous year closing balance because of January 1 in-service treatment of CPCN's

b) Actual Rate Base Continuity 2003-2008

TERASEN GAS INC.
ACTUAL RATE BASE CONTINUITY ($000's)
FOR THE YEARS ENDING DECEMBER 31

		2003	2004	2005	2006	2007	2008
1	Gross Plant In Service Opening	2,696,795	2,817,462	2,889,618	3,020,621	3,067,389	3,140,066
2	Additions	110,233	94,208	104,928	112,532	104,688	111,588
3	Retirements	(15,953)	(42,637)	(27,495)	(70,099)	(46,514)	(45,745)
4	Adjustments, Transfers, Recoveries	(635)	6,510	(44)	(2)	3,657	293
5	CPCN's	27,023	14,075	53,614	4,336	10,846	7,848
6	Gross Plant In Service Closing	2,817,462	2,889,618	3,020,621	3,067,389	3,140,066	3,214,050
7							
8	Intangible Plant Opening	837	837	837	837	837	1,614
9	Additions	-	-	-	-	-	-
10	Retirements	-	-	-	-	-	-
11	Adjustments	-	-	-	-	-	-
12	CPCN	-	-	-	-	777	-
13	Intangible Plant Closing	837	837	837	837	1,614	1,614
14							
15	CIAC Opening	(134,289)	(142,889)	(156,262)	(148,612)	(162,075)	(150,600)
16	Additions	(8,660)	(13,373)	(9,006)	(12,839)	(9,270)	(12,279)
17	Retirements	-	-	16,656	(625)	21,471	1,242
18	Adjustments	60	-	-	1	(726)	1
19	CIAC Closing	(142,889)	(156,262)	(148,612)	(162,075)	(150,600)	(161,636)
20							
21	CIAC Accumulated Amortization	32,764	41,338	51,042	44,913	53,394	40,486
22	Amortization	8,132	9,704	10,527	7,856	8,523	6,145
23	Retirements	-	-	(16,656)	625	(21,471)	(1,242)
24	Adjustments	442	-	-	-	40	(8)
25	CIAC Closing Accumulated Amortization	41,338	51,042	44,913	53,394	40,486	45,381
26							
27	Accumulated Depreciation Opening	(492,735)	(550,541)	(598,518)	(655,495)	(670,195)	(711,495)
28	Depreciation	(79,726)	(87,320)	(87,605)	(90,199)	(86,508)	(84,097)
29	Retirements[1]	15,953	42,637	27,495	70,099	45,213	45,745
30	Adjustments, Proceeds, Retirement Costs	5,967	(3,294)	3,133	5,400	(5)	6,361
31	Accumulated Depreciation Closing	(550,541)	(598,518)	(655,495)	(670,195)	(711,495)	(743,486)
32							
33	Opening Net Plant In Service[2]	2,130,395	2,180,282	2,240,331	2,266,600	2,300,196	2,327,919
34	Closing Net Plant In Service	2,166,207	2,186,717	2,262,264	2,289,350	2,320,071	2,355,923
35							
36	Mid Year Net Plant In Service	2,148,301	2,183,500	2,251,298	2,277,975	2,310,133	2,341,921
37	Adjustment to 13-month average	(6,533)	(7,492)	(5,344)	(1,745)	(2,663)	3,208
38	Work in progress, no AFUDC	6,565	4,695	14,510	9,927	7,719	7,062
39		2,148,333	2,180,703	2,260,464	2,286,157	2,315,189	2,352,191
40	Deferred Charges	29,488	23,763	6,274	9,424	(14,754)	(26,223)
41	Cash Working Capital	(13,742)	(15,339)	(15,436)	(21,327)	(24,259)	(27,614)
42	Gas In Storage Working Capital	83,461	112,112	151,056	160,586	142,265	164,419
43	Other Working Capital	6,699	7,424	8,481	10,469	10,563	12,360
44	Other	(4,704)	(1,959)	(2,749)	(2,673)	(3,459)	(3,256)
45							
46	Utility Rate Base	2,249,535	2,306,704	2,408,090	2,442,636	2,425,545	2,471,877

[3], [4], [5]

[3] Retirements not equal to GPIS in 2007 because of land retirement and gain/loss on sale of NGV cylinders

[4] Opening net plant in service not equal to previous year closing balance because of January 1 in-service treatment of CPCN's

[5] Cash working capital is the only amount that is affected by revenue normalization

c) Deferred Charges Continuity 2003-2008

TERASEN GAS INC.
DEFERRAL ACCOUNTS
MID-YEAR ACCOUNT BALANCE ($000's)

		Account	2003	2004	2005	2006	2007	2008
1	Margin Related							
2	Gas Cost Reconciliation Account (GCRA)	#17926	14,472	-	-	-	-	-
3	G.C.R.A. Interest	#17973	199	(622)	-	-	-	-
4	Midstream Cost Reconciliation Account (MCRA)	#17926	-	-	(27,859)	(15,997)	9,474	8,028
5	Commodity Cost Reconciliation Account (CCRA)	#18137	-	-	21,774	12,588	(27,337)	(24,129)
6	C.C.R.A./M.C.R.A. Interest	#17973	-	-	(1,095)	(1,669)	(2,151)	(2,371)
7	Revenue Stabilization Adjustment Mechanism (RSAM)	#17927	25,456	37,243	27,800	32,057	28,304	18,521
8	RSAM Interest	#17999	110	196	265	485	565	276
9	Revelstoke Propane Cost	#27902	6	52	161	58	(32)	(223)
10	SCP Net Mitigation Revenues	#17912	(3,156)	(1,863)	(1,023)	(2,293)	(4,123)	(4,488)
11	Total Margin Related		37,087	35,006	20,023	25,229	4,700	(4,386)
12								
13	Energy Policy Related							
14	Market Rebate Incentive- Water Heater Grants	#17909	20	4	-	-	-	-
15	NGV Conversion Grants	#17977	175	182	162	148	121	111
16	Demand Side Management	#17916	1,685	1,297	1,044	1,071	1,331	1,366
17	Demand Side Management DRIA	#17961	(327)	(348)	(225)	(73)	-	-
18	NGV Compression Equip. Recovery	#17992	1,385	1,172	1,030	870	622	374
19	Carbon Tax Implementation	#18512	-	-	-	-	-	52
20	Carbon Tax Cost of Service	#18513	-	-	-	-	-	(192)
21	Total Energy Policy Related		2,938	2,307	2,011	2,016	2,074	1,711
22								
23	Non-Controllable Items							
24	Deferred Interest	#17904	(4,182)	(3,413)	(2,317)	(1,183)	(51)	(806)
25	Deferred Interest - Customer Deposits		-	-	-	-	(117)	40
26	Property Tax Deferral	#17915	(869)	(1,355)	(744)	(330)	(742)	(876)
27	BCUC Levies	#18149	-	73	132	(54)	(252)	(286)
28	OSC Compliance Certification Costs	#18148	-	71	73	(43)	(106)	(17)
29	2005 BC Tax Rate Reduction Deferral	#17940	-	-	(375)	(386)	(11)	-
30	2006 LCT Elimination	#18502				(1,552)	(2,586)	(1,028)
31	Overheads Change - Income Tax Refund	#17995	(623)	(485)	(347)	(209)	(70)	-
32	CIAOC Software Tax Savings/OH Change	#17995	(3,635)	(2,827)	(2,019)	(1,211)	(404)	-
33	SCP-PG&E Contract Cancellation	#17936	445	1,748	2,629	2,320	1,657	993
34	SCP West to East Transmission	#17913	1,580	1,208	762	342	(340)	(1,264)
35	SCP Provincial Sales Tax Reassessment	#18504	-	-	-	5,015	8,610	7,241
36	CCT Deferral	#17924	(598)	(465)	(332)	(199)	(67)	-
37	CCT Assessment	#17929	266	484	421	204	99	11
38	Pension Variance	#17946	-	157	273	(1,100)	(2,387)	(1,068)
39	Insurance Variance	#17947	-	(439)	(581)	(245)	(171)	(199)
40	IFRS Conversion costs	#18509	-	-	-	-	-	49
41	Total Non-Controllable Items		(7,616)	(5,243)	(2,425)	1,369	3,062	2,790

TERASEN GAS INC.
DEFERRAL ACCOUNTS
MID-YEAR ACCOUNT BALANCE ($000's)- Continued

		Account	2003	2004	2005	2006	2007	2008
42	Application Costs							
43	2003 Revenue Requirement	#17989	226	240	175	110	54	15
44	2004-2007 Revenue Requirements	#17952	57	97	77	62	38	13
45	Future Revenue Requirements	#18160	-	-	-	8	33	53
46	ROE Hearing 2005	#17985	-	-	114	338	374	225
47	2001 Rate Design	#17974	173	58	-	-	-	-
48	Total Application Costs		456	395	366	518	499	306
49								
50	Other							
51	Other Post Employment Benefits	#17991/93	(6,699)	(10,273)	(14,333)	(18,829)	(23,599)	(27,314)
52	Earnings Sharing Mechanism	#17982	208	-	(441)	(1,998)	(2,286)	211
53	Bad Debt Allowance for Rates 14 & 14A	#17949	-	2	20	43	56	(27)
54	B.C. Hydro Service Agreement Costs	#17963	707	236	-	-	-	-
55	Coastal Facilities - Relocation	#17951	921	512	171	-	-	-
56	Coastal Facilities - Extraordinary Plant Loss - Lochburn	#17998	99	94	105	107	47	-
57	Coastal Facilities - Fraser Valley NBV Amortization	#17996	526	313	103	-	-	-
58	Coastal Facilities - Noncapital Finance Costs	#17984	549	181	-	-	-	-
59	ABC T Project Requirements Phase	#17918	45	15	-	-	-	-
60	Vehicle Lease Deferral	#17941	-	-	517	875	538	180
61	Burner Tip Service	#17972	(53)	(4)	(1)	-	-	-
62	Salmon Arm Reinforcement	#17990	34	-	-	-	-	-
63	Deferred 2000 SCP Cost of Service	#17997	286	222	158	94	31	-
64	TGS O&M Variance	#18506	-	-	-	-	58	174
65	TGS Amalgamation	#18503	-	-	-	-	66	132
66	Total Other		(3,377)	(8,702)	(13,701)	(19,708)	(25,089)	(26,644)
67								
68	Total Deferred Charges in Rate Base		29,488	23,763	6,274	9,424	(14,754)	(26,223)

d) Capital Expenditures 2003-2008

TERASEN GAS INC.
BASE CAPITAL EXPENDITURES ($000's)
FOR THE YEARS ENDING DECEMBER 31

		2003	2004	2005	2006	2007	2008
1	**Category A**						
2	Mains	4,212	5,303	7,405	8,147	8,106	10,991
3	Services	10,149	13,309	14,566	16,404	17,077	17,984
4	New Meters & Meters Recalled	17,479	15,424	15,349	16,189	13,687	14,878
5	**Total Category A**	31,840	34,036	37,319	40,741	38,871	43,852
6							
7							
8	**Category B**						
9	Transmission Plant	11,441	7,076	5,559	8,663	5,096	13,308
10	Distribution Plant	13,755	10,998	10,219	9,705	10,353	8,136
11	**Total Category B**	25,196	18,074	15,778	18,368	15,450	21,444
12							
13							
14	**Category C**						
15	IT	10,300	7,314	10,592	7,834	4,171	10,468
21	Non-IT	13,255	10,939	11,977	16,648	14,666	14,234
22	**Total Category C**	23,555	18,254	22,569	24,482	18,837	24,702
23							
24		80,591	70,364	75,667	83,591	73,158	89,998

Capital Expenditures Reconciliation to Plant Additions 2003- 2009

TERASEN GAS INC.
CAPEX TO ADDITIONS ($000's)
FOR THE YEARS ENDING DECEMBER 31

		2003	2004	2005	2006	2007	2008
1	CPCN's						
2	Opening Work in Progress	27,023	14,193	2,750	4,336	2,541	10,355
3	Add - Capital Expenditures- CPCNs	14,193	2,632	55,200	2,541	18,661	12,168
4	Less - Closing Work in Progress	(14,193)	(2,750)	(4,336)	(2,541)	(10,355)	(14,676)
5	Total Opening Plant Additions - CPCNs	27,023	14,075	53,614	4,336	10,846	7,848
6							
7	Non-CPCNs						
8	Opening Work in Progress	17,880	13,936	17,159	15,830	15,611	12,721
9	Add - Capital Expenditures- Non-CPCNs	80,591	70,364	75,667	83,591	73,158	89,998
10	Add- Adjustments[1]	595	1,058	1,778	1,613	1,241	86
11	Less - Closing Work in Progress	(13,936)	(17,159)	(15,844)	(15,611)	(12,721)	(18,760)
12	Non-CPCN Additions to Gas Plant in Service	85,130	68,199	78,760	85,423	77,289	84,045
13							
14	Less: Opening WIP Adjustment	(1)	-	(44)	(2)	-	-
15	Add: O&M Charged To Construction	25,104	26,009	26,212	27,111	27,399	27,543
16							
17	Total Plant Additions- Non-CPCNs	110,233	94,208	104,928	112,532	104,688	111,588

[1]Adjustments related to AFUDC, CIAC and removal costs

Terasen Gas Inc.

Terasen Gas (Vancouver Island) Inc.

Cash Working Capital Lead-Lag Study Review

June 10, 2009

Table of Contents

1.0 Summary of Findings

Terasen Gas Inc. ("TGI") retained KPMG to perform an independent review of the TGI and Terasen Gas Vancouver Island ("TGVI") Cash Working Capital Lead-Lag Study ("Study") in preparation of its 2010/11 Revenue Requirement Application.

Specifically, KPMG was engaged to assess the:

- Completeness of the revenue and expense components included in the study;
- Appropriateness and validity of the revenue and expense components;
- Reasonableness of the lead-lag calculation in total and for each component; and
- Comparability of TGI/TGVI's approach to the calculation of Cash Working Capital ("CWC") requirements of utilities in other jurisdictions.

Following the review of TGI/TGVI's Study, KPMG found that the Study:

- Is complete with respect to the inclusion of all major revenue and expense items as compared to the financial statements;
- Does not materially exclude any revenue and expense items as compared to the financial statements;
- Appropriately uses the 2007 study period to reflect activity expected in the 2010/11 forecast years;
- Appropriately and necessarily includes an adjustment for Carbon Tax introduced in 2008;
- Uses averaging assumptions for some lag periods that are reasonable and correct in calculation;
- Uses system generated data for the remaining lag periods which are reasonable and correct in calculation;
- Is consist with principles and guidance offered in FERC NOPR RM84-9-000, and in the approach used by utilities in other jurisdictions; and
- Excludes financial items from its net revenue lag calculation, which KPMG does not find to be inappropriate.

2.0 Purpose of the Report

TGI retained KPMG to perform an independent review of the TGI/TGVI Study in preparation of its 2010/11 Revenue Requirement Application. Specifically, KPMG was engaged to assess the:

- Completeness of the revenue and expense components included in the study;
- Appropriateness and validity of the revenue and expense components;
- Reasonableness of the lead-lag calculation in total and for each component; and
- Comparability of TGI's approach to the calculation of CWC requirements of utilities in other jurisdictions.

KPMG has provided the results of its review in this report. The structure of this report is as follows:

- *Section 1.0: Summary of Findings* – summarizes KPMG's findings extracted from detail in Section 6.0 and Appendix A;
- *Section 2.0: Purpose of Report* – outlines the engagement and structure of the report;
- *Section 3.0: Background* – provides an overview of lead-lag studies and CWC calculations as they relate to regulated utilities;
- *Section 4.0: KPMG Approach to Review* – explains how KPMG conducted its review and references documents used during the course of the review (detailed in Appendix C);
- *Section 5.0: Comparison to Other Utilities* – summarizes similarities and differences of lead-lag studies prepared by utilities in other jurisdictions (detailed in Appendix B); and
- *Section 6.0: KPMG Findings and Recommendations* – summarizes the results of KPMG's review in regards to completeness, appropriateness, reasonableness (detailed in Appendix A) and comparability to other utilities.

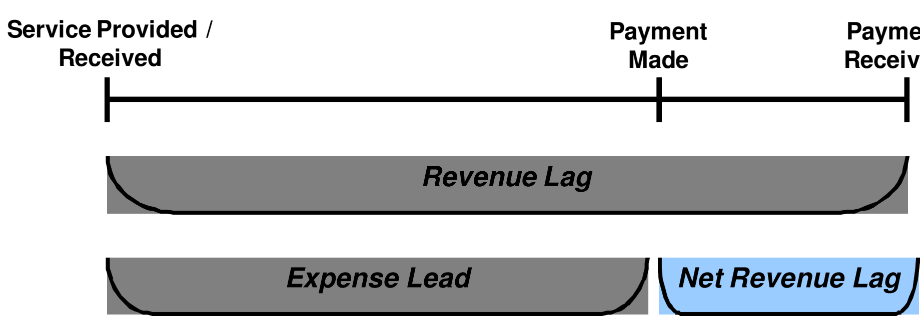
3.0 Background

A regulated utility's investment in working capital has historically been included in rate base to recognize the average investment required to pay expenses in advance of collecting revenues. This investment, additional to that in physical plant and equipment, represents the investment required to fund items such as inventories, prepayments and CWC to meet current obligations. Including working capital in rate base compensates investors for the cost of this capital. The subject of TGI/TGVI's Study, and subsequently the focus of KPMG's review, relates to the CWC component.

CWC requirements arise as revenues received by a utility typically lag behind the payment of goods and services used to provide service to customers. For many years of regulation history, utilities in North America have been expected to demonstrate the time lag between receipts and payments so that forecast CWC requirements are represented as accurately as possible in relation to forecast business activity. The calculation of this time lag and the conversion of this time lag into forecast dollar amounts is carried out through a lead-lag study.

A lead-lag study typically includes a period of time over which cash receipts and payments are analyzed in detail to determine a weighted average number of days for which investors or customers supply working capital to operate the utility. The resulting weighted average days is referred to as the net revenue lag.

Similar to the diagram in TGI/TGVI's Study, the resulting net revenue lag can be illustrated by the following diagram:



Revenue lag represents the weighted average number of days from the date service is provided to customers until the date payment is received from customers. Expense lead represents the weighted average number of days from the date a good or service is received until the date the payment is made to suppliers. The net of the two results in a net revenue lag.

A lead-lag study further separates these timeframes into specific lag components to facilitate assumptions and averaging where specific data is difficult and/or costly to obtain. Although there is some variation in definition from utility to utility, the separate components can be generally described as follows:

Service Lag – the service lag relates to the time period for which the utility provides service (revenue), or receives a good or service (expense). For services provided or received that are continuous in nature throughout the period, the service lag is calculated from the midpoint of the service period to when the service is complete (e.g. end of the month or a meter reading date). For other revenues and goods or services received, system data is typically analyzed to determine when the service lag period begins and ends.

Processing Lag – the processing lag relates to the time period from when service is complete to when the utility creates and issues an invoice (revenue) or arranges for payment following the receipt of an invoice from suppliers (expense). System data is typically analyzed to determine the weighted average processing lag.

Payment Lag – the payment lag relates to the time period from when an invoice is generated (revenue) or received (expense) to when payment is received (revenue) or made (expense). System data is typically analyzed to determine the weighted average payment lag.

The resulting net revenue lag is then multiplied by the daily forecast operating and maintenance costs to arrive at the forecast amount of CWC that investors are expected to provide the regulated utility.

In arriving at the forecast CWC, it is important for a utility to analyze current business information to provide the confidence that it accurately represents conditions for the forecast years. Generally utilities will use the most recent complete 12 month calendar year as the basis for its lead-lag study and make any significant adjustments that may have arisen since the study period or that are expected to arise in the future.

4.0 KPMG Approach to Review

As previously noted, KPMG was engaged by TGI to review its Study with respect to completeness, appropriateness and reasonability of the CWC calculation. KPMG was also engaged to prepare a comparison to the approaches taken by utilities in other jurisdictions. Although there is some reference to other utilities made in this section of the report, these comparisons are detailed in Section 5.0 and Appendix B.

KPMG's approach to the TGI/TGVI Study Review is founded on:

- An understanding of long standing accepted practice with respect to calculating CWC for regulated purposes, supported by comparisons to utilities in other jurisdictions and other regulatory documents;
- The ability to confirm that all material revenue and expense items were included in the Study through a comparison of items in the Study to TGI/TGVI's financial statements; and
- The assumption that the data within the lead-lag calculation models provided by TGI/TGVI accurately represents all major revenue and expense items, and that the study year chosen represents activity expected in the forecast years.

Specifically, KPMG sought answers to the following questions under the areas of completeness, appropriateness and reasonableness in assessing TGI/TGVI's CWC calculation:

Completeness:

- Are the expense and revenue items in the Study the same as those in TGI/TGVI's financial statements?
- Are there any items in the study period financial statements that are not included in the Study? If so, what is the rationale?

Appropriateness:

- Do the revenue and expense items in the Study accurately represent activity expected in the forecast years?
- Have there been any adjustments to the Study from the study period data? If so, what is the rationale?

Reasonableness:

- Do the calculations reasonably represent the timing from when service is received to when payment is made?
- Are the calculations in alignment with accepted practice in BC and other jurisdictions?

During the course of its review KPMG also referred to Federal Energy Regulatory Commission (FERC) Notice of Proposed Rulemaking (NOPR) RM84-9-000 issued April 5, 1984 on *Calculation of Cash Working Capital Allowance for Electric Utilities*. Although this document was not ultimately adopted by FERC, it was developed out of the need to establish principles around the CWC component of rate base:

> *"…A significant demonstrated "lag" in revenue collection in relation to the lag in the payment of expense would result in an addition to rate base to provide a return on the working cash required to be kept on hand … Any such adjustment to rate base must be supported by a fully-developed and reliable study …"*[1]

Regulated utilities in North America have historically prepared their CWC requirements in alignment with the principles set out in FERC's NOPR. As such, with respect to reviewing the completeness, appropriateness and reasonableness of the TGI/TGVI approach, KPMG also considered the practice of utilities in other jurisdictions. The lead-lag studies of these utilities and other regulatory documents referred to in this review are provided in Appendix C.

<u>*Restrictions*</u>

KPMG did not review or perform an audit with respect to source documentation during the course of this review (e.g. bank statements, invoices from suppliers, contracts). Throughout the engagement, KPMG has relied upon the information provided by TGI/TGVI. Although KPMG has considered the reasonableness of all information provided, it has not conducted independent investigation or performed other procedures to verify the accuracy, completeness or fair presentation of this information.

KPMG reserves the right, but will be under no obligation, to review all the calculations included or referred to herein and, if considered necessary, to revise the conclusions in the light of any information existing at the date of this report which becomes known to KPMG after the date of this report.

[1] FERC NOPR RM84-9-000, Calculation of Cash Working Capital Allowance for Electric Utilities, April 5, 1984; p. 2.

5.0 Comparison to Other Utilities

As previously noted, KPMG compared how other gas and electric regulated utilities prepare their CWC requirements as part of this review. Appendix B contains a table that summarizes these comparisons and Appendix C includes the specific documents to which KPMG referred to in drawing its comparisons. The following discusses a comparison of TGI/TGVI to the utilities set out in Appendix B.

Methodology

The regulated utilities compared to in BC and other jurisdictions all prepare a lead-lag study to calculate CWC requirements. The utilities vary slightly in the assumptions used, however whether six or twelve months of data has been analyzed or if average service time assumptions or invoice sampling is used, the information provided in the lead-lag studies is representative of each utility's recent business activity and is therefore assumed to be representative of business activity expected in the forecast years.

The methodology and approach used in the TGI/TGVI Study is similar to that of these other utilities.

Revenue Lag

The revenue lag days of the utilities compared is similar at an approximate 40-day weighted average lag time. This is reasonable to expect as tariff terms of service and payment do not tend to vary significantly from utility to utility and tariff revenue represents the most significant impact on the weighted average revenue lag days.

The methodology and approach used in the TGI/TGVI Study and the resulting revenue lag days is similar as compared to these other utilities.

Expense Lead

With respect to expense leads, comparing expense lead days between utilities is more difficult as the terms of service and payment can vary depending on the expense category. In addition, the utilities compared differ somewhat in how they arrive at the weighted average expense lead days. Some calculate it as an overall weighted average expense lead while others separate out operations and maintenance expenses from income taxes, other taxes, GST, etc.

The methodology and approach used in the TGI/TGVI Study is similar to that of the other utilities compared, and where comparable the resulting expense lead days are similar.

Financial Items

The most significant difference between jurisdictions appears to relate to financial items. Financial items include interest expense and equity-related payments such as dividends on common or preferred stock or distribution payments. FERC NOPR RM84-9-000 did not include financial items and proposed to limit the CWC calculation to including nine expenses which FERC had:

> *"… determined to have the most significant impact upon working cash needs. These expenses are (1) fossil fuel, (2) leased-nuclear fuel, (3) purchased power, (4) labor, (5) other operation and maintenance …, (6) payroll taxes, (7) ad valorem taxes, (8) revenue taxes, and (9) income taxes payable."*[2]

Further discussion regarding the treatment of financial items between utilities and jurisdictions is set out below.

Interest Expense

From the lead-lag studies reviewed, Alberta appears to be the only jurisdiction that consistently includes interest expense in the CWC calculation. Hydro One in Ontario and FortisBC in British Columbia are the only other utilities reviewed that include interest expense in their CWC calculation. The other utilities reviewed exclude interest expense including TGI/TGVI.

In its Decision U97065, the Alberta regulator states that interest on long term debt is to be included in the lead-lag calculation as the payment schedule is certain and there should be a lag or lead associated with this cost that is collected through customer tariffs.

The FERC NOPR excluded interest expense from the nine expenses but did not explain the rationale for the exclusion. In Ontario Power Generation's (OPG) lead-lag study it states that interest expense is not included in the study, and also does not provide the rationale:

> *"Consistent with regulatory practices in Ontario, corporate interest return on equity and certain non-cash items were excluded from the lead/lag study."*[3]

In testimony submitted by Mr. David Peterson in April 2008 in the state of New Jersey and in a study prepared by Navigant Consulting in 2006 for Hydro One Transmission it is argued that interest expense represents a legitimate contractual cash payment obligation that should be considered in determining the CWC requirements.

Dividend / Distribution Payments

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[2] FERC NOPR RM84-9-000, Calculation of Cash Working Capital Allowance for Electric Utilities, April 5, 1984; p. 27.
[3] Ontario Power Generation 2006 Lead/Lag Study, November 30, 2007, p. 8.

With respect to dividend / distribution payments, Alberta again appears to be the only jurisdiction that consistently includes payments associated with equity in the CWC calculation. All other utilities reviewed exclude equity-related payments including TGI/TGVI.

In its Decision U97065, the Alberta regulator stated that quarterly dividend payments relating to common and/or preferred equity are assumed to be related to funds used during the previous quarter and therefore result in a payment lag.

Similar to interest expense, FERC NOPR excluded equity-related payments from the nine expenses stating that it wanted to remain consistent with interest expense. Again, in OPG's lead-lag study there is reference to the exclusion but no rationale provided.

Not unlike the nature of interest expense, the argument for including equity-related payments is that they are legitimate contractual cash payment obligations to shareholders that should be considered in determining the CWC requirements.

The methodology and approach used in the TGI/TGVI Study to excluding financial items is similar to that of most of the other utilities compared.

6.0 KPMG Findings and Recommendations

Following the examination of TGI/TGVI's Study, KPMG found the following:

Completeness:

The TGI/TGVI Study is complete. KPMG confirmed in this review that the Study includes all the major revenue and expense items that have a significant impact on the results of the CWC calculation. KPMG also confirms that there have been no material exclusions in the Study with respect to revenue and expense items.

Appropriateness:

The revenue and expense items in the TGI/TGVI Study are appropriate. KPMG confirms that the use of 2007 actual data will accurately represent the activity expected in the 2010/11 forecast years. In addition, KPMG confirms that the adjustment to include Carbon Tax which was introduced in 2008 is not only appropriate, but necessary to be representative of what will occur in 2010/11.

Reasonableness:

The lead-lag day calculations in the TGI/TGVI Study are reasonable. KPMG confirms that where TGI/TGVI made averaging assumptions or used contract terms to determine lag days, these assumptions are reasonable and representative of the approach of other utilities as well.

KPMG also confirms that where system generated data for goods and services receipts, billing and payments was used to determine lag periods in whole or in part, that the calculations are correct and reasonable.

Comparison to Other Utilities:

KPMG's understanding is that TGI/TGVI based its Study primarily on historical establishment of CWC calculations with its regulator. KPMG confirms that TGI/TGVI's approach is also consist with the guidance offered in FERC NOPR RM84-9-000 and is in principle alignment with what utilities prepare for regulators in other jurisdictions.

With respect to the differences between utilities and jurisdictions on the matter of financial items, KPMG does not consider these items to be inappropriately excluded from the TGI/TGVI Study. The inclusion of these items in CWC calculations appears to be dominant in Alberta only and may be included in the context of other assumptions. KPMG recommends that TGI/TGVI review the financial items in the context of its operational requirements and the principles underlying the calculation of CWC in its own regulatory jurisdiction to determine if they should be included in future studies or not.

Appendix A: KPMG Review Detail

KPMG Review – TGI/TGVI CWC Study				
Report Components	**Completeness**	**Appropriateness of Components**	**Reasonableness of Calculations**	**Recommendations / Commentary on Lead/Lag Factor**
Methodology & Approach				
Revenue Lag	Methodology states to include all individual revenue items for the 2007 calendar year. KPMG confirms that revenue included in the Study represents the same in the 2007 income statement detail.	The Study uses 2007 data to calculate the net revenue lag days for 2010/11 CWC requirements. KPMG confirms that all revenue items in the Study are appropriate and none have been excluded; the use of 2007 data is appropriate as the results represent activity expected in 2010/11.	Customer tariff revenue lag days are calculated based on individual lag components: (1) service lag; (2) billing lag, and (3) collection lag. Other revenues were analyzed separately by transactions or assumptions were made to determine lag days. KPMG confirms the calculation of separate lag components in the Study is reasonable and characteristic of standard practice, as is the use of assumptions.	Consistent with standard practice in terms of including all revenue items, separating the lag components and using a representative year of data on which to base the study.
Expense Lead	Methodology states to include all individual expense items for the 2007 calendar year. KPMG confirms that expenses included in the Study represent the same in the 2007 income statement detail, with the exception of Carbon Ta introduced in 2008.	The Study uses 2007 data to calculate the net revenue lag days to calculation CWC for 2010/11; adjustments to include Carbon Tax have been made to better represent activity in the 2010/11 forecast years. KPMG confirms that all revenue items in the Study are appropriate and none have been excluded; the use of 2007 data is appropriate as the results represent activity expected in 2010/11.	Expense lead days are calculated based on 2 methods: (1) Services - from deemed receipt of service date (generally mid-point of period) to payment date, and (2) Goods - from date goods were received to payment date; analysis includes assumptions where data is not available. KPMG confirms the calculations of expense leads in the Study are reasonable and characteristic of standard practice, as is the use of assumptions or sample data as required.	Consistent with standard practice in terms of including all expense items and the use of a representative year of data on which to base the study. The use of assumptions or sample data to calculate representative expense leads is also in keeping with standard practice. Also see comments under Carbon Tax and Financial Items.
Cash Working Capital (CWC) Requirements	See comments above	See comments above	The Study uses a "dollar days" approach to weight the net revenue (lead) lag days. KPMG confirms this approach is	Other utilities vary in how they perform the math and present the calculations; however the weighting approach by TGI/TGVI is consistent across the comparable utilities.

KPMG Review – TGI/TGVI CWC Study				
Report Components	**Completeness**	**Appropriateness of Components**	**Reasonableness of Calculations**	**Recommendations / Commentary on Lead/Lag Factor**
			reasonable and characteristic of standard practice to derive a weighted average net lag day amount to determine forecast CWC requirements.	
Revenue				
Customer Tariff Revenue	Customer tariff revenues in the 2007 Study are the same as in the 2007 income statement detail. TGI analyzed 100% of 2007 available data for purposes of this study.	Customer tariff revenues in 2007 are representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Service Lag: Calculation reflects from the mid-point of the billing month as customers receive service continuously through the month; tariff defines 12 billing periods in one year therefore service lag is: 365/12/2 = 15.2 lag days. Billing Lag: Calculation includes residential and commercial classes billed the same day as the metering reading date with the exception of 26.84% of the customers where the bill was generated the day following; industrial customers were analyzed separately using system data. Collection Lag: Each customer payment transaction was analyzed from system data to determine the collection lag.	Customer tariff revenue in the Study is complete, the components are appropriate and the calculations are reasonable and characteristic of standard practice.
Other Revenues:				
Late Payment Charges	Late payment charges in the 2007 Study are the same as in the 2007 income statement detail.	Late payment charges in 2007 are representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Residential and small commercial customer revenue lags are assumed for this revenue group. This assumption is reasonable as late payment charges follow through the next service cycle to payment and are included on the	Late payment revenue in the Study is complete and the components are appropriate. The assumption to adopt the weighted revenue lag of residential and commercial customers is reasonable.

KPMG Review – TGI/TGVI CWC Study				
Report Components	**Completeness**	**Appropriateness of Components**	**Reasonableness of Calculations**	**Recommendations / Commentary on Lead/Lag Factor**
			next customer bill.	
Returned Cheque Charges	Returned cheque charges in the 2007 Study are the same as in the 2007 income statement detail.	Returned cheque charges in 2007 are representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Residential and small commercial customer revenue lags are assumed for this revenue group. This assumption is reasonable as returned cheque charges follow through the next service cycle to payment and are included on the next customer bill.	Returned cheque charges in the Study are complete and the components are appropriate. The assumption to adopt the weighted revenue lag of residential and commercial customers is reasonable.
Connection Charges	Connection charges in the 2007 Study are the same as in the 2007 income statement detail.	Connection charges in 2007 are representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Residential and small commercial customer revenue lags are assumed for this revenue group. This assumption is reasonable as connection charges follow through the service cycle to payment and are included on the customer bill.	Connection charges in the Study are complete and the components are appropriate. The assumption to adopt the weighted revenue lag of residential and commercial customers is reasonable.
Other Utility Income	Other utility income in the 2007 Study is the same as in the 2007 income statement detail.	Other utility income in 2007 is representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Residential and small commercial customer revenue lags are assumed for this revenue group. This assumption is reasonable as other utility income follows through the service cycle to payment and are included on the customer bill.	Other utility income in the Study is complete and the components are appropriate. The assumption to adopt the weighted revenue lag of residential and commercial customers is reasonable.
NGV Tank Rental	NGV tank rental charges in the 2007 Study are the same as in the 2007 income statement detail.	NGV tank rental charges in 2007 are representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Residential and small commercial customer revenue lags are assumed for this revenue group. This assumption is reasonable as NGV tank rentals follow through the service cycle to payment and	NGV tank rental in the Study is complete and the components are appropriate. The assumption to adopt the weighted revenue lag of residential and commercial customers is reasonable.

KPMG Review – TGI/TGVI CWC Study				
Report Components	**Completeness**	**Appropriateness of Components**	**Reasonableness of Calculations**	**Recommendations / Commentary on Lead/Lag Factor**
			are included on the next customer bill.	
Royalty Revenue (TGVI only)	Royalty revenue in the 2007 Study is the same as in the 2007 income statement detail.	Royalty revenues in 2007 are representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Lag days calculated from the midpoint of each quarter as these payments are received by government 4 times per year. Lag days = 365 / 4 / 2 = 45.6 days	Royalty revenue in the Study is complete, the components are appropriate and the calculations are reasonable and characteristic of standard practice.
Expenses				
Gas Purchases	Gas purchases in the 2007 Study are the same as in the 2007 income statement detail. TGI analyzed 100% of 2007 available data for purposes of this study.	Gas purchases in 2007 are representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Lead time calculated from the mid-point of service period to the payment date; all 2007 invoices were analyzed; payments contractually required through wire transfer on the 25th of the month following service. Lead days = 15.2 + 25 = 40.2 days	Gas purchases in the Study are complete, the components are appropriate and the calculations are reasonable and characteristic of standard practice.
Transportation (TGVI only)	Transportation charges in the 2007 Study are the same as in the 2007 income statement detail.	Transportation charges in 2007 are representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Lead time calculated based on contract terms; service lead is calculated from mid-month, invoicing occurs on the 15th of the following month and payment is made 10 days following the invoice. Lead days = 15.2 + 15 + 10 = 40.2 days	Transportation charges in the Study are complete and the components are appropriate. The calculations based on contract terms are reasonable and characteristic of other utility practice.
Operations & Maintenance:				
Payroll and Benefits	Payroll and benefit expense in the 2007 Study are the same as in the 2007 income statement detail.	Payroll and benefits expense in 2007 are representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Lead time for payroll calculated based on salary type (M&S salary, hourly, COPE salary, hourly; IBEW) and the use of average salaries in each category to determine weighted lead days. Lead time for benefits based on salary type, monthly and quarterly	Payroll and benefits expense in the Study are complete, the components are appropriate and the calculations are reasonable and characteristic of standard practice.

KPMG Review – TGI/TGVI CWC Study				
Report Components	**Completeness**	**Appropriateness of Components**	**Reasonableness of Calculations**	**Recommendations / Commentary on Lead/Lag Factor**
			midpoint service period assumptions and payment due date assumptions.	
Contractors	Contractor expense in the 2007 Study is the same as in the 2007 income statement detail.	Contractor expense in 2007 is representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Invoices from the supplier that represents the majority of payments were analyzed; service lead assumed to start at the midpoint of the month; payment lead from the end of the month to when payment was made plus 1 day for Electron Fund Transfer (EFT) clearing. Lead days = 15.2 + 14.1 + 1 = 30.3 days	Contractor expense in the Study is complete and the components are appropriate. Basing the calculations on a sample supplier is reasonable and characteristic of other utility practice.
Vehicles	Vehicle expense in the 2007 Study is the same as in the 2007 income statement detail.	Vehicle expense in 2007 is representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Invoices from the supplier that represents the majority of payments were analyzed; service lead assumed to start at the midpoint of the month; payment lead from the end of the month to when payment was made plus 1 day for EFT clearing. Lead days = 15.2 + 6.1 + 1 = 22.3 days	Vehicle expenses in the Study are complete and the components are appropriate. Basing the calculations on a sample supplier is reasonable and characteristic of other utility practice.
Materials	Material expense in the 2007 Study is the same as in the 2007 income statement detail.	Material expense in 2007 is representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Invoices from the 3 largest suppliers were analyzed; service lead assumed to start at the midpoint of the month; payment lead from the end of the month to when payment was made plus 1 day for EFT clearing. TGVI adopted the TGI materials lead days as the majority of transactions relate to costs allocated from TGI. Lead days = 15.2 + 32.99 + 1 =	Material expense in the Study is complete and the components are appropriate. Basing the calculations on sample suppliers is reasonable and characteristic of other utility practice.

KPMG Review – TGI/TGVI CWC Study				
Report Components	**Completeness**	**Appropriateness of Components**	**Reasonableness of Calculations**	**Recommendations / Commentary on Lead/Lag Factor**
			49.2 days	
Computer Costs	Computer expense in the 2007 Study is the same as in the 2007 income statement detail.	Computer expense in 2007 is representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Invoices from the 5 largest suppliers were analyzed; service lead assumed to start at the midpoint of the month; payment lead from the end of the month to when payment was made plus 1 day for EFT clearing. TGVI adopted the TGI materials lead days as the majority of transactions relate to costs allocated from TGI. Lead days = 15.2 + 26.2 + 1 = 42.4 days	Computer expense in the Study is complete and the components are appropriate. Basing the calculations on sample suppliers is reasonable and characteristic of other utility practice.
Other O&M	Other O&M expense in the 2007 Study are the same as in the 2007 income statement detail.	Other O&M expense in 2007 is representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Invoices from the all remaining suppliers not in the categories above were analyzed; service lead assumed to start at the midpoint of the month; payment lead from the end of the month to when payment was made plus 1 day for EFT clearing. Lead days = 15.2 + 33.44 + 1 = 49.6 days	Other O&M expense in the Study is complete, the components are appropriate and the calculations are reasonable and characteristic of standard practice.
Property Tax	Property tax in the 2007 Study is the same as in the 2007 income statement detail.	Property tax in 2007 is representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Lead time calculated by weighting dollars from the date of payment to the midpoint of the study year (July 1, 2007) which assumes that property taxes are consumed evenly throughout the year. EFT clearing of 1 day is added. Lead days = 0.98 + 1 = 1.98 days	Property tax in the Study is complete, the components are appropriate and the calculations are reasonable and characteristic of standard practice.
Franchise Tax	Franchise tax in the 2007 Study includes all of the payments made in 2007.	Franchise tax in 2007 is representative of activity expected in 2010/11. All items are appropriate to include, none have	Lead time calculated by weighting dollars from the midpoint of the previous year to the payment clearing date in the study year.	Franchise tax in the Study is complete, the components are appropriate and the calculations are reasonable and characteristic of standard practice.

KPMG Review – TGI/TGVI CWC Study				
Report Components	**Completeness**	**Appropriateness of Components**	**Reasonableness of Calculations**	**Recommendations / Commentary on Lead/Lag Factor**
		been excluded.	Payment is made in Feb or Oct for the previous year. EFT clearing of 1 day is added. Lead days = 419.25 + 1 = 420.25 days	
Goods and Services Tax (GST)	GST in the 2007 Study includes all of the payments made in 2007.	GST in 2007 is representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Lead days calculated by assuming a midpoint of the previous month for service lag and remittance records for the date of payment. EFT clearing of 1 day is added. Lead days = net weighted payment lead 35.43 days + net weighted receipt lag 11.32 days = 24.10 days	GST in the Study is complete, the components are appropriate and the calculations are reasonable and characteristic of standard practice.
Provincial Sales Tax (PST) / Innovative Clean Energy (ICE) Levy	PST / ICE in the 2007 Study includes all of the payments made in 2007.	PST/ICE in 2007 is representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Lead days calculated by assuming a midpoint of the previous month for service lag and remittance records for the date of payment. EFT clearing of 1 day is added. Lead days = 15.2 + 17.6 + 1 = 33.8 days	PST/ICE in the Study is complete, the components are appropriate and the calculations are reasonable and characteristic of standard practice.
Carbon Tax	Introduced by the BC Provincial Government July 1, 2008; study has included 6 months of the 2008 calendar year to better represent activity expected in 2010/11.	Carbon tax for 6 months of 2008 is representative of activity expected in 2010/11. All items are appropriate to include, none have been excluded.	Payments made for 6 months of 2008 were analyzed; payments relate to the previous month so a midpoint of the month was chosen for the service lag; payments on the 15th of the following month for customer funded amounts and the end of the following month for TGI were analyzed to determine the payment lag. EFT clearing of 1 day is added. Lead days = 15.23 + 12.83 + 1 = 29.1 days	Carbon tax in the Study is complete, the components are appropriate and the calculations are reasonable and characteristic of standard practice. The inclusion of Carbon Tax with a representative period of data to support is consistent with updating the study appropriately to best represent activity expected in the test years 2010/11.
Income Tax	Income tax in the 2007 Study is the same as in the 2007 financial	Income tax in 2007 is representative of activity expected	Lead time determined theoretically so as to relate to regulated taxes	Income tax in the Study is complete. The assumption to adopt the mid-

KPMG Review – TGI/TGVI CWC Study				
Report Components	**Completeness**	**Appropriateness of Components**	**Reasonableness of Calculations**	**Recommendations / Commentary on Lead/Lag Factor**
	statement detail.	in 2010/11. All items are appropriate to include, none have been excluded.	only; Lead days = 15.2 days assuming payment is made at the end of the same month of consumption.	month service lag and payment at the end of the same month is reasonable and characteristic of standard practice.

Appendix B: Comparison to Other Utilities

✓ **- included in study**
✗ **- excluded from study**

	TGI	TGVI	Fortis BC	Fortis Alberta	AltaLink	ATCO Gas	Enbridge	OPG	Hydro One	Nfld Power	RMP
Jurisdiction	BC	BC	BC	Alberta	Alberta	Alberta	Ontario	Ontario	Ontario	Nfld	Utah
Type of Utility	Gas	Gas	Electric	Electric D	Electric T	Gas	Gas	Electric G	Electric T	Electric	Electric
Method to CWC	Lead/Lag	Lead/Lag	Lead/Lag	Lead/Lag	Lead/Lag	Lead/Lag	Lead/Lag	Lead/Lag	Lead/Lag	Lead/Lag	Lead/Lag
Study Year	2007	2007	n/a[1]	2006	2005	2003/04	n/a[1]	2006	2005	2005	2007
Revenue											
Customer Tariffs	✓	✓	✓	✓	n/a	✓	✓	n/a	n/a	✓	✓
ISO Revenues	n/a	n/a	✓	n/a	✓	n/a	n/a	✓	✓	n/a	n/a
Other Revenues	✓	✓	✓	✓	✓	✓	n/a	✓	✓	✓	✓
Expenses											
Cost of Fuel	✓	✓	✓	n/a	n/a	✓	✓	✓	n/a	n/a	✓
ISO / Access Pymt	n/a	n/a	✓	✓	n/a	n/a	n/a	✓	n/a	n/a	n/a
Labour Related	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Other OM&A	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Income Taxes	✓	✓	✓	✗	✓	✓	✗	✓	✓	✓	✓
Taxes Other Than Income	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Financial Items											
Interest Expense	✗	✗	✓	✓	✓	✓	✗	✗	✓	✗	✗
Equity Dividends	✗	✗	✗	✓	✓	✓	✗	✗	✗	✗	✗
Net Revenue Lag											

Acronyms: D, T, G – Distribution, Transmission, Generation; OM&A – Operating, Maintenance and Administration Expense; OPG – Ontario Power Generation; RMP – Rocky Mountain Power

[1] Information extracted from OPG and Hydro One application information.

Appendix C: References

Alberta Energy and Utilities Board, Decision U97065 1996 Electric Tariff Applications, Volume 1, October 31, 1997.

ATCO Gas, 2005-2007 General Rate Application, Volume 2, Tab 2.2 Lead-Lag Study, May 2005.

AltaLink Management Ltd., 2007-2008 General Tariff Application, Section 7.5 Allowance for Working Capital, April 2006.

Federal Energy Regulatory Commission, Notice of Proposed Rulemaking, Docket No. RM84-9-000, Calculation of Cash Working Capital Allowance for Electric Utilities, Issued April 5, 1984.

FortisAlberta Inc., 2008/2009 Phase I Tariff Application, Section 8 - Appendix H, 2006 Lead-Lag Study, May 29, 2007.

Hydro One Networks Inc., 2006 Transmission General Rate Application, Working Capital and Lead/Lag, Navigant Consulting Report: *A Determination of the Working Capital Requirements of Hydro One's Transmission Business*, July 19, 2006.

Newfoundland Power, 2008 General Rate Application, Cash Working Capital Lead/Lag Study, May 2007.

Pacificorp Rocky Mountain Power, 2008 General Rate Case, Lead Lag Study, July 17, 2008.

Testimony of David Peterson on Behalf of the New Jersey Department of the Public Advocate, Division of Rate Counsel; I/M/O The Petition of New Jersey Natural Gas Company for Approval of an Increase in its Gas Rates, Depreciation Rates for Gas Property, and for Changes in the Tariff for Gas Service, Pursuant to N.J.S.A. 48:2-18 and 48:2-21, April 28, 2008.

Terasen Gas Inc.

Terasen Gas (Vancouver Island) Inc.

Cash Working Capital Lead-Lag Study

March, 2009

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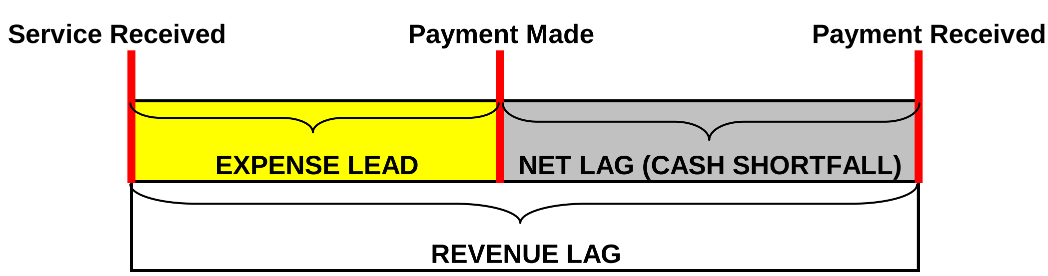
TABLE OF SCHEDULES

I. INTRODUCTION

The objective of the Lead-Lag study is to provide a measure of cash working capital needs for Terasen Gas Inc ("TGI") and Terasen Gas (Vancouver Island) Inc ("TGVI) in order to support their future working capital submissions before the British Columbia Utilities Commission (BCUC). Cash working capital is defined as the average amount of capital provided by investors in the company, over and above investments in plant and intangibles, to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The periods are usually expressed in terms of lead or lag days. A lead-lag study is required to derive the appropriate cash working capital requirements of the Companies. The study recognizes that there are timing differences between when TGI and TGVI provide a service and when they receive payment thereon (**revenue lag**) as well as the time between when they receive a service and subsequently make payment thereon (**expense lead**). The difference between the total revenue lag and total expense lead is the **net lag**. A net lag number greater than zero indicates a cash working capital shortfall position; this occurs when the payment of an expense precedes the collection of its related revenue stream. In some cases however, revenue may be received prior to payment for the related expense (a net lead or negative net lag), which indicates a cash working capital surplus position. Schedule I-1 illustrates the components of the lead/lag as discussed above.

Schedule I-1 – Lead Lag Schematic Diagram



II. SUMMARY OF KEY FINDINGS

The lead lag days determined in this study have been used for the computation of the cash working capital requirements in the 2010-2011 Revenue Requirement Applications of Terasen Gas Inc ("TGI") and Terasen Gas (Vancouver Island) Inc ("TGVI").

Lag days for total revenue and lead days for total expenditure are calculated by means of a weighted average of the individual components. The net lag days are then calculated and applied to forecast expenditures for 2010 and 2011 to determine the cash working capital requirements for each of 2010 and 2011.

Schedules II-1 and II-2 for TGI and Schedules II-3 and II-4 for TGVI summarize the cash working capital requirements and lead lag days for each significant receipt and expenditure component.

Schedule II-1 – TGI 2010 Cash Working Capital Requirements

Line	Particulars	2010 Budget Amount	Lead Lag Days	Dollar Days
1	**Gas Sales and Transportation Revenue**			
2	Residential (R1)	914,487	38.3	35,024,864
3	Small Commercial (R2)	302,127	39.0	11,782,949
4	Large Commercial (R3)	192,044	37.5	7,201,650
5	Seasonal (R4)	1,491	35.9	53,541
6	NGV Service (R6)	1,065	41.7	44,427
7	Large Industrial	104,648	45.2	4,730,099
8				
9	**Total Gas Sales and Transportation Revenue**	1,515,863	38.8	58,837,530
10				
11	**Other Revenues**			
12	Late Payment Charges	2,982	38.3	114,211
13	Returned Cheque Charges	82	38.3	3,141
14	Connection Charges	2,879	38.3	110,266
15	Other Utility Income	16,479	38.3	631,138
16				
17	**Total Other Revenues**	22,422	38.3	858,755
18				
19	**TOTAL REVENUES**	1,538,285	38.8	59,696,285
20				
21	Gas Purchases	975,597	40.2	39,218,999
22	Operation & Maintenance Purchases	192,823	25.5	4,916,987
23	Property Taxes	49,193	2.0	98,386
24	Franchise Taxes	10,321	420.3	4,337,916
25	Goods and Service Tax	13,095	38.8	508,100
26	Provincial Sales Tax (Social Services Tax)	43,126	37.1	1,599,975
27	Carbon Tax (Jul-08 to Dec-08)	97,701	29.1	2,843,110
28	Income Tax	31,622	15.2	480,654
29				
30	**TOTAL EXPENDITURES**	1,413,479	38.2	54,004,127
31				
32	**NET LEAD-LAG DAYS (L19-L30)**		0.6	
33				
34	**2010 BUDGETED EXPENDITURES**	1,413,479		
35				
36	**CASH WORKING CAPITAL**		$2,324	
37				

Schedule II-2 – TGI 2011 Cash Working Capital Requirements

Line	Particulars	2011 Budget Amount	Lead Lag Days	Dollar Days
1	**Gas Sales and Transportation Revenue**			
2	Residential (R1)	922,147	38.3	35,318,234
3	Small Commercial (R2)	309,076	39.0	12,053,945
4	Large Commercial (R3)	198,170	37.5	7,431,386
5	Seasonal (R4)	1,502	35.9	53,936
6	NGV Service (R6)	1,081	41.7	45,094
7	Large Industrial	107,388	45.2	4,853,946
8				
9	**Total Gas Sales and Transportation Revenue**	1,539,365	38.8	59,756,541
10				
11	**Other Revenues**			-
12	Late Payment Charges	2,987	38.3	114,402
13	Returned Cheque Charges	82	38.3	3,141
14	Connection Charges	2,905	38.3	111,262
15	Other Utility Income	18,385	38.3	704,142
16				
17	**Total Other Revenues**	24,359	38.3	932,946
18				
19	**TOTAL REVENUES**	1,563,724	38.8	60,689,487
20				
21	Gas Purchases	976,614	40.2	39,259,883
22	Operation & Maintenance Purchases	201,617	25.5	5,141,234
23	Property Taxes	50,211	2.0	100,422
24	Franchise Taxes	10,506	420.3	4,415,672
25	Goods and Service Tax	13,313	38.8	516,559
26	Provincial Sales Tax (Social Services Tax)	44,376	37.1	1,646,351
27	Carbon Tax (Jul-08 to Dec-08)	125,507	29.1	3,652,264
28	Income Tax	31,654	15.2	481,141
29				
30	**TOTAL EXPENDITURES**	1,453,799	38.0	55,213,524
31				
32	**NET LEAD-LAG DAYS (L19-L30)**		0.8	
33				
34	**2011 BUDGETED EXPENDITURES**	1,453,799		
35				
36	**CASH WORKING CAPITAL**		$3,186	
37				

Schedule II-3 – TGVI 2010 Cash Working Capital Requirements

Line	Particulars	2010 Budget Amount	Lead Lag Days	Dollar Days
1	Residential (R1)			-
2	Small Commercial (R2)			-
3	Large Commercial (R3)			-
4	Other Revenue			-
5	Royalty Revenue			-
6				
7	**TOTAL REVENUES**			-
8				
9	Gas Purchases			-
10	Transportation Costs			-
11	Operation & Maintenance Expenses			-
12	Property Taxes			-
13	Goods and Service Tax			-
14	Provincial Sales Tax (Social Services Tax)			-
15	Carbon Tax (Jul-08 to Dec-08)			-
16	Income Tax			-
17				
18	**TOTAL EXPENDITURES**	-		-
19				
20	**NET LEAD-LAG DAYS (L7-L18)**			
21				
22	**2010 BUDGETED EXPENDITURES**	-		
23				
24	**CASH WORKING CAPITAL**			
25				

To be updated with data from TGVI RRA filing

* TGVI RRA filing to be submitted Jun 19/09

Schedule II-4 – TGVI 2011 Cash Working Capital Requirements

Line	Particulars	2011 Budget Amount	Lead Lag Days	Dollar Days
1	Residential (R1)			-
2	Small Commercial (R2)			-
3	Large Commercial (R3)			-
4	Other Revenue			-
5	Royalty Revenue			-
6				
7	**TOTAL REVENUES**			-
8				
9	Gas Purchases			-
10	Transportation Costs			-
11	Operation & Maintenance Expenses			-
12	Property Taxes			-
13	Goods and Service Tax			-
14	Provincial Sales Tax (Social Services Tax)			-
15	Carbon Tax (Jul-08 to Dec-08)			-
16	Income Tax			-
17				
18	**TOTAL EXPENDITURES**			-
19				
20	**NET LEAD-LAG DAYS (L7-L18)**			
21				
22	**2011 BUDGETED EXPENDITURES**			
23				
24	**CASH WORKING CAPITAL**			
25				

To be updated with data from TGVI RRA filing

* TGVI RRA filing to be submitted Jun 19/09

III. METHODOLOGY AND APPROACH

The methodology used to determine the lead lag days for individual revenue and expenditure items generally follows that which is commonly accepted in regulatory literature. In addition, the methodology is consistent with that used in previous studies by predecessor companies BC Gas Inc and Centra Gas British Columbia Inc.

The test period for this lead/lag study is the 2007 calendar year. On July 1, 2008, a Carbon Tax was introduced by the BC Provincial Government. Given the effective date, the study period for the Carbon Tax consists of the last 6 months of the 2008 calendar year.

This lead/lag analysis takes into account both the working capital requirements associated with lag times as well as the offsetting working capital requirements associated with lead times. Two primary categories of leads and lags were considered: 1) lead times related to the payment for goods and services received by TGI and TGVI, or *"expense leads"* and 2) lag times related to revenues and the respective collection of those amounts owed to TGI and TGVI, or *"revenue lags"*.

The two major categories 1) Revenues and 2) Expenses were further broken down into their individual components to obtain the corresponding individual lead/lag times. The results were then rolled up through a weighted average into total lag days for Revenues and total lead days for Expenses. Total lag days for Revenues were then deducted from total lead days for Expenses to arrive at net lag days which were then applied to total expenditures to arrive at Cash Working Capital requirements.

In past TGVI lead/lag studies the weighted average total Revenue lag days was deducted from each of the component Expense lead days rather than from the total Expense lead days as is done in this study. Either methodology yields the same Cash Working Capital requirements.

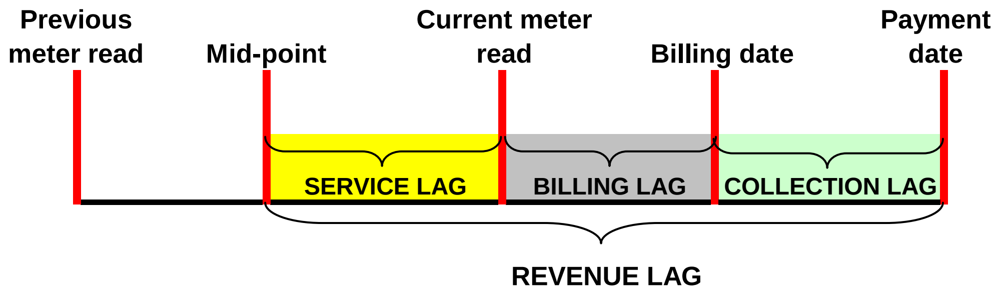
A. Calculation of Revenue Lag

The lag days pertaining to revenue receipts are determined by measuring the elapsed time between the date the service is deemed to be rendered and the date TGI and TGVI receive the related payments from the customer. The revenue lag is the sum of the service lag, the billing lag and the collection lag.

- The service lag is the number of days from the deemed receipt date of service (generally the mid-point of the cycle) to the meter reading date.
- The billing lag is the number of days between the meter reading date and the billing date.
- The collection lag is the number of days from the billing date to the date the payment is received from the customer.

Schedule III-1 illustrates the components of the revenue lag as discussed above.

Schedule III-1 – Revenue Lag Schematic Diagram



B. Calculation of Expense Lead (Lag)

The expenditure lead days are derived using one of two methods depending on whether goods or services are involved. In the case of services, the lead days are determined by measuring the elapsed time from the deemed receipt service date (generally the mid-point) to the date payment is made by the Company. For physical goods, the lead days are determined by measuring the elapsed time from the date the goods are received to the date the Company pays for them.

C. Calculation of Cash Working Capital Requirements

Once the revenue lags and expense leads (lags) are determined, the calculation of the cash working capital requirement involves the following steps:

1. For the individual revenue and expense components, multiply the applicable lead/lag days by the respective forecast revenue and expenditure amount to derive the *dollar days*.
2. Divide the total revenue and expenditure dollar days by the total forecast revenues and expenditures to derive *total weighted average revenue lag days and expenditure lead days*.
3. Deduct the total weighted average expenditure lead days from the total weighted average revenue lag days to determine the *net weighted average lag days.*
4. Multiply total budgeted expenditures by the net weighted average lag days and divide this product by 365 days to determine the ***cash working capital requirement of the Company.***

IV. REVENUE LAGS

TGI and TGVI recognize two revenue steams: A) Gas Sales and Transportation Revenues and B) Other Revenues.

<u>Gas Revenue Receipts</u>

The revenue lag days for residential and commercial customers are derived from the assessment of three time frames:

A. *Service Lag* – the time from the deemed average receipt date of service to the average meter reading date
B. *Billing Lag* – the time from the average meter reading date to the average date the customer is billed, and
C. *Collection Lag* – the time from the average billing date to the average date the customer pays the bill

A. Service Lag

The service receipt date is assumed to be the mid-point of the billing month given that customers are expected to receive service evenly throughout the service period. The average days between the deemed service receipt date and meter reading date is 30.4 days, calculated based on 12 billing periods in a 365 day year as defined under the Company's Tariff. When a service is continuous, such as gas sales, the mid-point of the service period is considered the service lag, which would be 15.2 (30.4/2) using the above approach. This is consistent with the approach used in previous studies of predecessor companies, BC Gas Inc and Centra Gas British Columbia Inc.

B. Billing Lag

Whereas TGI and TGVI aim to bill customers on the same day as the gas meter reading date, during the test period 26.84% of the total customer base was billed one day subsequent to the meter reading date. This lag time is built into the average billing lag days calculation for each customer rate category in the residential and commercial classes. For large industrial customers, a separate analysis was necessary as the average meter reading date differs from the average billing date for this group. The entire large industrial customer population (approximately 24,000 individual customer payment transactions) was analyzed and a weighted average billing lag was determined for TGI and TGVI large industrial customers respectively.

C. Collection Lag

TGI and TGVI bill customers for gas consumption every month. Payment is due 22 days following the invoiced date. All customers do not necessarily pay on the due date. For the purposes of the lead/lag study, every customer payment transaction (approximately 10.3 million invoice records) was analyzed to derive the average collection lag days for TGI and TGVI.

D. Other Revenues

Other revenue receipts consist of the following major items:

1. Late Payment Charges
2. Returned Cheque Charges
3. Connection Charges
4. Other Utility Income
5. NGV Tank Rental
6. Royalty Revenue (TGVI only)

Other Revenues are primarily a product of residential and small commercial customers. Hence the weighted average lag days associated with residential and small commercial revenues were applied to Other Revenues. The lag days for Royalty Revenue in TGVI was also calculated separately given it all comes from a single source.

V. EXPENSE LEADS (LAGS)

Expense leads and lags correspond to the lead or lag times associated with the payment for goods and services provided to TGI and TGVI by their respective vendors/suppliers. Similar to past Lead Lag studies, eight major groupings of expenses were considered:

A. Gas Purchases
B. Operations and Maintenance
C. Property Taxes
D. Franchise Taxes
E. Goods and Service Tax
F. Provincial Sales Tax
G. Carbon Tax
H. Income Tax

Each of these groupings and the associated expense lead or lag times are discussed below.

Expense Summary

The expense lead was calculated by analyzing each of TGI and TGVI's expenses for 2007 to determine the average number of lead days between when a service is received and when payment is made. Accounts Payable transaction detail for all of 2007 was analyzed. Known payment dates and cycles for various recurring expenditures were also utilized.

Expense lead times were derived for each of the expense items and then dollar-weighted to produce total weighted average expenditure lead days.

A. Gas Purchases

TGI and TGVI purchase their gas requirements from numerous vendors. Given that gas purchases comprise the majority of expenditures, each vendor was analyzed in detail. For each vendor, the average service lead time was calculated as being the mid-point between service start date and service end date (15.2 days). The average payment lead time was deemed to be 25 days as the payment contracts states the vendor will invoice TGI/TGVI by the 15th of the following month, at which time payment is due 10 days later. The service lead time was added together with payment lead time to arrive at a total lead time of 40.2 days.

B. Operations and Maintenance ("O&M")

To determine the lead days for O&M expenses, these expenses were grouped according to general ledger account. The primary groupings for TGI are comprised of six broad categories: payroll and benefits, materials, contractors, vehicles, computer costs and other O&M. The expense lead times related with each category of O&M are discussed in the following section.

1. Payroll and Benefits

Payroll and Benefits is comprised of a number of expense-related items:

Payroll

There are four different categories of payroll:

1. Management & Exempt Employees (M&E)
2. Canadian Office and Professional Employees (COPE) (TGI only)
3. International Brotherhood of Electrical Workers (IBEW)
4. M&E, COPE Part time and Temporary

Depending on the category, each of these has different payment terms and different lead/lag days.

The M&E and COPE payroll categories are both based on a biweekly pay period. For this group, actual payment occurs 1 day prior to the end of the biweekly pay period. The total average of 6 lead days is determined by adding the elapsed days from the midpoint to the end of the pay period (service lead of 7 days) and the elapsed days from the end of the pay period to the payment date (payment lag of 1 day).

For the IBEW group, actual payment occurs 7 days subsequent to the end of the biweekly pay period. Thus the service lead is 7 days similar to M&E and COPE while the payment lead is 7 days for a total average of 14 lead days.

For the M&E and COPE Part Time and Temporary actual payment occurs 6 days subsequent to the end of the biweekly pay period producing a total average of 13 lead days.

Benefits

Based upon known service periods and specifically recurring payment due dates, lead days are calculated individually for each benefit type:

- Employer portion of Canadian Pension Plan
- Employer portion of Employment Insurance
- Medical Services Plan
- Workers Compensation
- Long Term Disability
- Extended Health and Dental Plans
- Life Insurance
- Pension
- Employee Savings Plan
- Employee Incentive Plans

2. Contractors, Vehicles, Materials, Computer Costs

Samples of the largest suppliers in each category were analyzed. For goods and services received, the lead days were calculated from the midpoint of the service period to the date of invoice payment.

Typically materials and computer costs are made by TGI with subsequent allocations being made to TGVI. In these cases, the lead days calculated for TGI are also assigned to TGVI.

3. Other O&M

Remaining suppliers not falling into the categories above were analyzed and a dollar weighting of the payment leads were captured. Once again, the lead days were calculated from the midpoint of the service period to the date of invoice payment.

C. Property Tax

TGI and TGVI make property tax payments to approximately 100 municipalities within the province of British Columbia. These payments are generally made once a year, with the majority of payments occurring within one or two days of July 2nd. A mid- year approach was used to determine deemed receipt of service while actual payment records were analyzed to determine the payment lead. Total lead days were calculated as the dollar weighted number of days between deemed receipt of service and payment date.

D. Franchise Tax

Franchise fees are collected only in TGI from customers located within municipal boundaries in the Inland and Columbia service areas. Fees are collected from customers through the Energy billing system on a monthly basis. These fees are typically remitted to the municipalities in either February or October of the following year. A mid-year approach was used to determine the deemed receipt date of service while actual payment records were examined to determine the payment lead. Total lead days were calculated as the dollar weighted number of days between deemed receipt of service and payment date.

E. Goods and Services Tax

TGI and TGVI recover Canadian Goods and Services tax (GST) paid to suppliers on the purchase of goods and services and remit GST that they collect on revenues from customers. The Lead Days for GST were determined as follows:

- For GST paid on purchases of goods and services from outside suppliers the dollar weighted average lead days for gas purchases and other operating and maintenance expenditures were assigned.
- For GST collected on revenues from customers the weighted average lag time of revenues was assigned
- The lead days determined above were subsequently weighted by the respective GST dollar amounts to provide a lead day calculation for the net GST amount

F. Provincial Sales Tax / Innovative Clean Energy Levy

TGI and TGVI remit Provincial Sales Tax (PST) collected on revenues from commercial customers. The Innovative Clean Energy (ICE) Levy, collected from all customers, is related to purchases of electricity, natural gas, fuel oil and propane. PST and ICE are remitted together typically a month following month of service. A mid-month approach was used to determine receipt date of service while actual remittance records were examined to determine the payment lead.

G. Carbon Tax

As of July 1, 2008 a Carbon Tax on all fossil fuels consumed was implemented by the BC Provincial Government. Amounts paid are related to both funds collected from customers as well as self-assessed carbon tax amounts. Amounts collected from customers are remitted by the 15th of the month following month of service while self assessed amounts are remitted at the end of the month following month of service. A mid-month approach was used to determine receipt date of service while actual remittance records were examined to determine the payment lead.

H. Income Tax

An analysis of actual income tax remittances in any given year for TGI and TGVI include both regulated and non-regulated aspects. For the purposes of this lead lag study, only the regulated aspects of taxes paid are considered. Accordingly, an examination of actual remittance records is not considered applicable. The methodology for determining the amount and timing of regulated taxes paid is therefore on a theoretical basis and is in accordance with one of the three accepted methods in the Income Tax Act for calculating monthly instalment payments. Commencing in January, 1/12 of the estimated tax payable for the current tax year is due at the end of each month of the taxation year. On this basis a mid-month approach is used to determine the receipt date of service while an end of month date is used as payment date.

Appendix J

TARIFF CHANGES AND HISTORIC RATE CONTINUITY SCHEDULES

BC GAS UTILITY LTD.
CALCULATION OF CUSTOMERS' RATES
EFFECTIVE MARCH 1, 2003
BCUC ORDER NO G-7-03

Line No.	**RATE SCHEDULE 1: RESIDENTIAL SERVICE** Particulars	**2002 Rates** Lower Mainland	Inland	Columbia	**2003 Revenue Requirement and Rider Changes** Lower Mainland	Inland	Columbia	**March 1, 2003 Permanent Rates** Lower Mainland	Inland	Columbia
	-1	(2)	-3	-4	-5	-6	-7	-8	-9	-10
1	Basic Charge per Month	$10.00	$10.00	$10.00	$0.31	$0.31	$0.31	$10.31	$10.31	$10.31
2										
3										
4	Delivery Charge per gigajoule	$2.502	$2.502	$2.502	$0.077	$0.077	$0.077	$2.579	$2.579	$2.579
5										
6										
7	Gas Cost Recovery Charge per GJ	$6.061	$5.955	$6.052	$0.000	$0.000	$0.000	$6.061	$5.955	$6.052
8										
9	Riders: 1 Propane Surcharge		$2.661			$0.000			$2.661	
10	2 Jan - Feb 2003 Rate Increase Recovery (see page 14)	$0.000	$0.000	$0.000	$0.043	$0.043	$0.043	$0.043	$0.043	$0.043
11	3 Earnings Sharing	($0.011)	($0.011)	($0.011)	$0.011	$0.011	$0.011	$0.000	$0.000	$0.000
12	5 RSAM (see page 15)	$0.100	$0.100	$0.100	$0.034	$0.034	$0.034	$0.134	$0.134	$0.134
13	6 GCRA	$0.570	$0.570	$0.570	$0.000	$0.000	$0.000	$0.570	$0.570	$0.570
14										
15										
16	Total Variable Cost per GJ	$9.222	$9.116	$9.213	$0.165	$0.165	$0.165	$9.387	$9.281	$9.378
17										
18	Revelstoke Variable Cost per GJ									
19	(Includes Rider 1)		$11.777			$0.165			$11.942	
20										
21										

1 Note 1: The Rider 1 Propane Surcharge decrease of ($0.564)/GJ is the difference between the ($1.410)/GJ Revelstoke propane decreas
2 and the sum of the Gas Cost Recovery Charge decrease of ($0.479)/GJ and the Rider 6 GCRA decrease of ($0.367)/GJ.

Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE	2002 Rates			2003 Revenue Requirement and Rider Changes			March 1, 2003 Permanent Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Basic Charge per Month	$21.00	$21.00	$21.00	$0.64	$0.64	$0.64	$21.64	$21.64	$21.64
2										
3										
4	Delivery Charge per gigajoule	$2.095	$2.095	$2.095	$0.064	$0.064	$0.064	$2.159	$2.159	$2.159
5										
6										
7	Gas Cost Recovery Charge per GJ	$6.160	$6.048	$6.146	$0.000	$0.000	$0.000	$6.160	$6.048	$6.146
8										
9	Riders: 1 Propane Surcharge		$1.437			$0.00			$1.437	
10	2 Jan - Feb 2003 Rate Increase Recovery (see page 14)	$0.000	$0.000	$0.000	$0.037	$0.037	$0.037	$0.037	$0.037	$0.037
11	3 Earnings Sharing	($0.009)	($0.009)	($0.009)	$0.009	$0.009	$0.009	$0.000	$0.000	$0.000
12	5 RSAM (see page 15)	$0.100	$0.100	$0.100	$0.034	$0.034	$0.034	$0.134	$0.134	$0.134
13	6 GCRA	$0.610	$0.610	$0.610	$0.000	$0.000	$0.000	$0.610	$0.610	$0.610
14										
15										
16	Total Variable Cost per GJ	$8.956	$8.844	$8.942	$0.144	$0.144	$0.144	$9.100	$8.988	$9.086
17										
18	Revelstoke Variable Cost per GJ									
19	(Includes Rider 1)		$10.281			$0.144			$10.425	
20										
21										

1 Note 1: The Rider 1 Propane Surcharge decrease of ($0.585)/GJ is the difference between the ($1.410)/GJ Revelstoke propane decrease
2 and the sum of the Gas Cost Recovery Charge decrease of ($0.437)/GJ and the Rider 6 GCRA decrease of ($0.388)/GJ. 1

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	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE	**2002 Rates**			**2003 Revenue Requirement and Rider Changes**			**March 1, 2003 Permanent Rates**		
Line No.	Particulars	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Basic Charge per Month	$112.00	$112.00	$112.00	$3.43	$3.43	$3.43	$115.43	$115.43	$115.43
2										
3										
4	Delivery Charge per gigajoule	$1.806	$1.806	$1.806	$0.055	$0.055	$0.055	$1.861	$1.861	$1.861
5										
6										
7	Gas Cost Recovery Charge per GJ	$5.916	$5.819	$5.913	$0.000	$0.000	$0.000	$5.916	$5.819	$5.913
8										
9	Riders: 1 Propane Surcharge		$1.794			$0.00			$1.794	
10	2 Jan - Feb 2003 Rate Increase Recovery (see page 14)	$0.000	$0.000	$0.000	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025
11	3 Earnings Sharing	($0.007)	($0.007)	($0.007)	$0.007	$0.007	$0.007	$0.000	$0.000	$0.000
12	5 RSAM (see page 15)	$0.100	$0.100	$0.100	$0.034	$0.034	$0.034	$0.134	$0.134	$0.134
13	6 GCRA	$0.482	$0.482	$0.482	$0.000	$0.000	$0.000	$0.482	$0.482	$0.482
14										
15										
16	Total Variable Cost per GJ	$8.297	$8.200	$8.294	$0.121	$0.121	$0.121	$8.418	$8.321	$8.415
17										
18										
19										
20	Revelstoke Variable Cost per GJ									
21	(Includes Rider 1)		$9.994			$0.121			$10.115	
22										
23										

1 Note 1: The Rider 1 Propane Surcharge decrease of ($0.664)/GJ is the difference between the ($1.410)/GJ Revelstoke propane decrease
2 and the sum of the Gas Cost Recovery Charge decrease of ($0.442)/GJ and the Rider 6 GCRA decrease of ($0.304)/GJ. 1

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Line No.	RATE SCHEDULE 4: SEASONAL SERVICE	2002 Rates			2003 Revenue Requirement and Rider Changes			March 1, 2003 Permanent Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Basic Charge per Month	$372.00	$372.00	$372.00	$11.00	$11.00	$11.00	$383.00	$383.00	$383.00
2										
3	Delivery Charge per gigajoule									
4	(a) Off-Peak Period	$0.644	$0.644	$0.644	$0.020	$0.020	$0.020	$0.664	$0.664	$0.664
5	(b) Extension Period	$1.301	$1.301	$1.301	$0.040	$0.040	$0.040	$1.341	$1.341	$1.341
6										
7	Gas Cost Recovery Charge per GJ									
8	(a) Off-Peak Period	$5.661	$5.580	$5.670	$0.000	$0.000	$0.000	$5.661	$5.580	$5.670
9	(b) Extension Period	$5.661	$5.580	$5.670	$0.000	$0.000	$0.000	$5.661	$5.580	$5.670
10										
11	Unauthorized Gas Charge	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
12	per GJ during peak period									
13										
14										
15	Riders: 2 Jan - Feb 2003 Rate Increase Recovery (see page 14)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16	3 Earnings Sharing	($0.003)	($0.003)	($0.003)	$0.003	$0.003	$0.003	$0.000	$0.000	$0.000
17	6 GCRA	$0.350	$0.350	$0.350	$0.000	$0.000	$0.000	$0.350	$0.350	$0.350
18										
19	Total Variable Cost per GJ between									
20	(a) Off-Peak Period	$6.652	$6.571	$6.661	$0.023	$0.023	$0.023	$6.675	$6.594	$6.684
21	(b) Extension Period	$7.309	$7.228	$7.318	$0.043	$0.043	$0.043	$7.352	$7.271	$7.361

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Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE		2002 Rates			2003 Revenue Requirement and Rider Changes			March 1, 2003 Permanent Rates	
	Particulars		Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	-1		-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Basic Charge per Month		$495.00	$495.00	$495.00	$15.00	$15.00	$15.00	$510.00	$510.00	$510.00
2											
3											
4	Demand Charge per GJ		$12.384	$12.384	$12.384	$0.379	$0.379	$0.379	$12.763	$12.763	$12.763
5											
6											
7	Delivery Charge per gigajoule		$0.502	$0.502	$0.502	$0.015	$0.015	$0.015	$0.517	$0.517	$0.517
8											
9											
10	Gas Cost Recovery Charge per GJ		$5.661	$5.580	$5.670	$0.000	$0.000	$0.000	$5.661	$5.580	$5.670
11											
12	Riders:	2 Jan - Feb 2003 Rate Increase Recovery (see page 14)	$0.000	$0.000	$0.000	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013
13		3 Earnings Sharing	($0.005)	($0.005)	($0.005)	$0.005	$0.005	$0.005	$0.000	$0.000	$0.000
14		6 GCRA	$0.350	$0.350	$0.350	$0.000	$0.000	$0.000	$0.350	$0.350	$0.350
15											
16	Total Variable Cost per GJ		$6.508	$6.427	$6.517	$0.033	$0.033	$0.033	$6.541	$6.460	$6.550

Line No.	RATE SCHEDULE 6: NGV - STATIONS		2002 Rates			2003 Revenue Requirement and Rider Changes			March 1, 2003 Permanent Rates		
	Particulars		Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month		$52.20	$52.20	$52.20	$1.60	$1.60	$1.60	$53.80	$53.80	$53.80
2											
3											
4	Delivery Charge per gigajoule		$2.871	$2.871	$2.871	$0.088	$0.088	$0.088	$2.959	$2.959	$2.959
5											
6											
7	Gas Cost Recovery Charge per GJ		$5.361	$5.306	$5.306	$0.000	$0.000	$0.000	$5.361	$5.306	$5.306
8											
9	Riders:	2 Jan - Feb 2003 Rate Increase Recovery (see page 14)	$0.000	$0.000	$0.000	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014
10		3 Earnings Sharing	($0.008)	($0.008)	($0.008)	$0.008	$0.008	$0.008	$0.000	$0.000	$0.000
11		6 GCRA	$0.174	$0.174	$0.174	$0.000	$0.000	$0.000	$0.174	$0.174	$0.174
12											
13											
14	Total Variable Cost per GJ		$8.398	$8.343	$8.343	$0.110	$0.110	$0.110	$8.508	$8.453	$8.453

RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	Existing Rates	2003 Revenue Requirement and Rider Changes	March 1, 2003 Permanent Rates
	(1)	(2)	-3	-4
1	Lower Mainland Service Area			
2	Basic Charge per Month	$73.50	$2.20	$75.70
3	Minimum Charges	$125.00	$0.00	$125.00
4				
5				
6	Delivery Charge per gigajoule	$2.871	$0.088	$2.959
7				
8	Gas Cost Recovery Charge per GJ	$5.361	$0.000	$5.361
9				
10	Compression Charge per GJ	$5.280	$0.000	$5.280
11				
12	Riders: 2 Jan - Feb 2003 Rate Increase Recovery (see page 14)	$0.000	$0.014	$0.014
13	3 Earnings Sharing	($0.008)	$0.008	$0.000
14	6 GCRA	$0.174	$0.000	$0.174
15				
16				
17	Total Variable Cost per GJ	$13.678	$0.110	$13.788

Line No.	**RATE SCHEDULE 7: INTERRUPTIBLE SALES** Particulars	**2002 Rates** Lower Mainland	Inland	Columbia	**2003 Revenue Requirement and Rider Changes** Lower Mainland	Inland	Columbia	**March 1, 2003 Permanent Rates** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$743.00	$743.00	$743.00	$23.00	$23.00	$23.00	$766.00	$766.00	$766.00
2										
3	Delivery Charge per gigajoule	$0.836	$0.836	$0.836	$0.026	$0.026	$0.026	$0.862	$0.862	$0.862
4										
5	Commodity Charge per GJ									
6	- Fixed Pricing	$5.661	$5.580	$5.670	$0.000	$0.000	$0.000	$5.661	$5.580	$5.670
7										
8	- Index Pricing	Sumas Daily	Sumas Daily	Sumas Daily				Sumas Daily	Sumas Daily	Sumas Daily
9		Price + the	Price + the	Price + the				Price + the	Price + the	Price + the
10		greater of	greater of	greater of				greater of	greater of	greater of
11		$0.05/GJ or Cost	$0.05/GJ or Cost	$0.05/GJ or Cost				$0.05/GJ or Cost	$0.05/GJ or Cost	$0.05/GJ or Cost
12										
13	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
14										
15										
16										
17	Riders: 2 Jan - Feb 2003 Rate Increase Recovery (see page 14)	$0.000	$0.000	$0.000	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009
18	3 Earnings Sharing	($0.003)	($0.003)	($0.003)	$0.003	$0.003	$0.003	$0.000	$0.000	$0.000
19	6 GCRA	$0.350	$0.350	$0.350	$0.000	$0.000	$0.000	$0.350	$0.350	$0.350
20										
21										
22										
23	Total Variable Cost per GJ - Fixed Pricing Option	$6.844	$6.763	$6.853	$0.038	$0.038	$0.038	$6.882	$6.801	$6.891

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Line No.	**RATE SCHEDULE 22: LARGE INDUSTRIAL T-SERVICE** Particulars	**2002 Rates** Lower Mainland	Inland	Columbia	**2003 Revenue Requirement and Rider Changes** Lower Mainland	Inland	Columbia	**March 1, 2003 Permanent Rates** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$3,097.00	$3,097.00	$3,097.00	$95.00	$95.00	$95.00	$3,192.00	$3,192.00	$3,192.00
2										
3	Delivery Charge (Interr. MTQ)	$0.620	$0.620	$0.620	$0.019	$0.019	$0.019	$0.639	$0.639	$0.639
4										
5										
6	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
7										
8										
9	Demand Surcharge per GJ	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00	$17.00	$17.00	$17.00
10										
11	Balancing Service per GJ	$0.30	$0.30	n/a	$0.000	$0.000	$0.000	$0.30	$0.30	n/a
12		$1.10	$1.10	n/a	$0.000	$0.000	$0.000	$1.10	$1.10	n/a
13										
14										
15	Charges per GJ for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
16										
17										
18	Administration Charge	$87.00	$87.00	$87.00	($17.00)	($17.00)	($17.00)	$70.00	$70.00	$70.00
19										
20	Riders: 2 Jan - Feb 2003 Rate Increase Recovery (see page 14)	$0.000	$0.000	$0.000	$0.007	$0.007	$0.007	$0.007	$0.007	$0.007
21	3 Earnings Sharing	($0.002)	($0.002)	($0.002)	$0.002	$0.002	$0.002	$0.000	$0.000	$0.000
22										
23										
24										
25										
26	Total Variable Cost per GJ - Fixed Pricing Option	$0.618	$0.618	$0.618	$0.028	$0.028	$0.028	$0.646	$0.646	$0.646

RATE SCHEDULE 22A:
LARGE INDUSTRIAL T-SERVICE

Line No.	Particulars	2002 Rates	2003 Revenue Requirement and Rider Changes	March 1, 2003 Permanent Rates
	(1)	(2)	(3)	(4)
1	Basic Charge per Month	$4,067.00	$124.00	$4,191.00
2				
3	Delivery Charge per GJ - Firm			
4	(a) Firm DTQ	$9.944	$0.304	$10.248
5	(b) Firm MTQ	$0.070	$0.002	$0.072
6				
7	Delivery Charge per GJ - Interr MTQ	$0.795	$0.024	$0.819
8				
9	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
10				
11				
12	Demand Surchage per GJ	$17.00	$0.00	$17.00
13				
14	Balancing Service per GJ			
15	(a) between and including Apr. 1 and Oct. 31	$0.300	$0.00	$0.300
16	(b) between and including Nov. 1 and Mar. 31	$1.100	$0.00	$1.100
17				
18	Charges per GJ for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
19				
20				
21	Replacement Gas	Sumas Daily Price		Sumas Daily Price
22		plus 20 Percent		plus 20 Percent
23				
24	Administration Charge	$87.00	($17.00)	$70.00
25				
26	Riders: 2 Jan - Feb 2003 Rate Increase Recovery (see page 14)	$0.000	$0.006	$0.006
27	3 Earnings Sharing	($0.002)	$0.002	$0.000
28				
29	Total Variable Cost per GJ			
30	(a) Firm MTQ	$0.068	$0.010	$0.078
31				
32	(b) Interruptible MTQ	$0.793	$0.032	$0.825

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Line No.	**RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE** Particulars	**2002 Rates** Columbia Except Elkview	Elkview Coal	**2003 Revenue Requirement and Rider Changes** Columbia Except Elkview	Elkview Coal	**March 1, 2003 Permanent Rates** Columbia Except Elkview	Elkview Coal
	(1)	-2	(3)	(4)	-5	-6	-7
1	Basic Charge per Month	$3,835.00	$3,835.00	$117.00	$117.00	$3,952.00	$3,952.00
2							
3	Delivery Charge per GJ - Firm						
4	(a) Firm DTQ	$6.336	$1.438	$0.194	$0.044	$6.530	$1.482
5	(b) Firm MTQ	$0.068	$0.068	$0.002	$0.002	$0.070	$0.070
6							
7	Delivery Charge per GJ - Interr MTQ						
8	(a) between and including Apr. 1 and Oct. 31	$0.631	$0.157	$0.019	$0.005	$0.650	$0.162
9	(b) between and including Nov. 1 and Mar. 31	$0.910	$0.226	$0.028	$0.007	$0.938	$0.233
10							
11	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
12							
13							
14	Demand Surcharge per GJ	$17.00	$17.00	$0.00	$0.00	$17.00	$17.00
15							
16	Charges per GJ for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
17							
18							
19							
20	Administration Charge	$87.00	$87.00	($17.00)	($17.00)	$70.00	$70.00
21							
22	Riders: 2 Jan - Feb 2003 Rate Increase Recovery (see page 1	$0.000	$0.000	$0.005	$0.003	$0.005	$0.003
23	3 Earnings Sharing	($0.002)	($0.001)	$0.002	$0.001	$0.000	$0.000
24							
25							
26							
27							
28							
29							
30	Total Variable Cost per GJ						
31	(a) Firm MTQ	$0.066	$0.067	$0.009	$0.006	$0.075	$0.073
32	(b) Interruptible MTQ - Summer	$0.629	$0.156	$0.026	$0.009	$0.655	$0.165
33	- Winter	$0.908	$0.225	$0.035	$0.011	$0.943	$0.236
34							

Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE	2002 Rates			2003 Revenue Requirement and Rider Changes			March 1, 2003 Permanent Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	-1	(2)	-3	-4	-5	-6	-7	-8	-9	-10
1	Basic Charge per Month	$112.00	$112.00	$112.00	$3.43	$3.43	$3.43	$115.43	$115.43	$115.43
2										
3										
4	Delivery Charge per GJ	$1.806	$1.806	$1.806	$0.055	$0.055	$0.055	$1.861	$1.861	$1.861
5										
6	Administration Charge	$87.00	$87.00	$87.00	($17.00)	($17.00)	($17.00)	$70.00	$70.00	$70.00
7										
8	Sales									
9	(a) Charge per GJ for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per GJ for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per GJ for UOR Gas									
13										
14	Riders: 2 Jan - Feb 2003 Rate Increase Recovery (see page 14)	$0.000	$0.000	$0.000	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025
15	3 Earnings Sharing	($0.007)	($0.007)	($0.007)	$0.007	$0.007	$0.007	$0.000	$0.000	$0.000
16	5 RSAM (see page 15)	$0.100	$0.100	$0.100	$0.034	$0.034	$0.034	$0.134	$0.134	$0.134
17										
18										
19										
20	Total Variable Cost per GJ	$1.899	$1.899	$1.899	$0.121	$0.121	$0.121	$2.020	$2.020	$2.020

Line No.	RATE SCHEDULE 25 GENERAL FIRM T-SERVICE	2002 Rates			2003 Revenue Requirement and Rider Changes			March 1, 2003 Permanent Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$495.00	$495.00	$495.00	$15.00	$15.00	$15.00	$510.00	$510.00	$510.00
2										
3	Demand Charge per GJ	$12.384	$12.384	$12.384	$0.379	$0.379	$0.379	$12.763	$12.763	$12.763
4										
5										
6	Delivery Charge (Interr. MTQ)	$0.502	$0.502	$0.502	$0.015	$0.015	$0.015	$0.517	$0.517	$0.517
7										
8	Administration Charge	$87.00	$87.00	$87.00	($17.00)	($17.00)	($17.00)	$70.00	$70.00	$70.00
9										
10	Sales									
11	(a) Charge per GJ for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per GJ for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per GJ for UOR Gas									
15										
16										
17										
18	Riders: 2 Jan - Feb 2003 Rate Increase Recovery (see page 14)	$0.000	$0.000	$0.000	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013
19	3 Earnings Sharing	($0.005)	($0.005)	($0.005)	$0.005	$0.005	$0.005	$0.000	$0.000	$0.000
20										
21										
22	Total Variable Cost per GJ - Fixed Pricing Option	$0.497	$0.497	$0.497	$0.033	$0.033	$0.033	$0.530	$0.530	$0.530

BC GAS UTILITY LTD.
CALCULATION OF CUSTOMERS' RATES
EFFECTIVE MARCH 1, 2003
BCUC ORDER NO. G-7-03

Line No.	RATE SCHEDULE 27: INTERRUPTIBLE T-SERVICE	2002 Rates			2003 Revenue Requirement and Rider Changes			March 1, 2003 Permanent Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$743.00	$743.00	$743.00	$23.00	$23.00	$23.00	$766.00	$766.00	$766.00
2										
3										
4	Delivery Charge (Interr. MTQ)	$0.836	$0.836	$0.836	$0.026	$0.026	$0.026	$0.862	$0.862	$0.862
5										
6	Administration Charge	$87.00	$87.00	$87.00	($17.00)	($17.00)	($17.00)	$70.00	$70.00	$70.00
7										
8	Sales									
9	(a) Charge per GJ for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per GJ for Backstopping Gas									
11	(c) Charge per GJ for UOR Gas									
12										
13	Riders: 2 Jan - Feb 2003 Rate Increase Recovery (see page 14)	$0.000	$0.000	$0.000	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009
14	3 Earnings Sharing	($0.003)	($0.003)	($0.003)	$0.003	$0.003	$0.003	$0.000	$0.000	$0.000
15										
16										
17	Total Variable Cost per GJ - Fixed Pricing Option	$0.833	$0.833	$0.833	$0.038	$0.038	$0.038	$0.871	$0.871	$0.871

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE Particulars	Existing March 1, 2003 Rates Lower Mainland	 Inland	 Columbia	Gas Cost Changes Lower Mainland	 Inland	 Columbia	April 1, 2003 Permanent Rates Lower Mainland	 Inland	 Columbia
	-1	(2)	-3	-4	-5	-6	-7	-8	-9	-10
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$10.31	$10.31	$10.31	$0.00	$0.00	$0.00	$10.31	$10.31	$10.31
3										
4	Delivery Charge per gigajoule	$2.579	$2.579	$2.579	$0.000	$0.000	$0.000	$2.579	$2.579	$2.579
5										
6	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.043	$0.043	$0.043	$0.000	$0.000	$0.000	$0.043	$0.043	$0.043
7	3 Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
8	5 RSAM	$0.134	$0.134	$0.134	$0.000	$0.000	$0.000	$0.134	$0.134	$0.134
9	Subtotal Delivery Margin Related Charges per GJ	$2.756	$2.756	$2.756	$0.000	$0.000	$0.000	$2.756	$2.756	$2.756
10										
11	Commodity Related Charges									
12	Gas Cost Recovery Charge per GJ	$6.061	$5.955	$6.052	$1.669	$1.673	$1.659	$7.730	$7.628	$7.711
13						1				
14	Riders: 1 Propane Surcharge (Revelstoke only)		$2.661			($1.673)			$0.988	
15	6 GCRA	$0.570	$0.570	$0.570	$0.000	$0.000	$0.000	$0.570	$0.570	$0.570
16	Subtotal Commodity Related Charges per GJ	$6.631	$6.525	$6.622	$1.669	$1.673	$1.659	$8.300	$8.198	$8.281
17										
18	Total Variable Cost per GJ	$9.387	$9.281	$9.378	$1.669	$1.673	$1.659	$11.056	$10.954	$11.037
19										
20	Revelstoke Variable Cost per GJ									
21	(Includes Rider 1)		$11.942			$0.000			$11.942	
22										
23										
24										

25 Note 1: The Revelstoke propane cost is unchanged from existing rates. The Rider 1 Propane Surcharge decrease of ($1.673)/GJ offsets the Gas Cost Recovery Charge increase of $1.673/GJ.

xx Note 1: The Rider 1 Propane Surcharge decrease of ($0.564)/GJ is the difference between the ($1.410)/GJ Revelstoke propane decrease
and the sum of the Gas Cost Recovery Charge decrease of ($0.479)/GJ and the Rider 6 GCRA decrease of ($0.367)/GJ.

TariffApr2003
Rate2

BC GAS UTILITY LTD.
CALCULATION OF CUSTOMERS' RATES
EFFECTIVE APRIL 1, 2003
BCUC ORDER NO G-19-03

TAB 1
PAGE 2
SCHEDULE 2

Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE	Existing March 1, 2003 Rates			Gas Cost Changes			April 1, 2003 Permanent Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$21.64	$21.64	$21.64	$0.00	$0.00	$0.00	$21.64	$21.64	$21.64
3										
4	Delivery Charge per gigajoule	$2.159	$2.159	$2.159	$0.000	$0.000	$0.000	$2.159	$2.159	$2.159
5										
6	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.037	$0.037	$0.037	$0.000	$0.000	$0.000	$0.037	$0.037	$0.037
7	3 Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
8	5 RSAM	$0.134	$0.134	$0.134	$0.000	$0.000	$0.000	$0.134	$0.134	$0.134
9	Subtotal Delivery Margin Related Charges per GJ	$2.330	$2.330	$2.330	$0.000	$0.000	$0.000	$2.330	$2.330	$2.330
10										
11	Commodity Related Charges									
12	Gas Cost Recovery Charge per GJ	$6.160	$6.048	$6.146	$1.639	$1.647	$1.632	$7.799	$7.695	$7.778
13										
14	Riders: 1 Propane Surcharge (Revelstoke only)		$1.437			($1.647)[1]			($0.210)	
15	6 GCRA	$0.610	$0.610	$0.610	$0.000	$0.000	$0.000	$0.610	$0.610	$0.610
16	Subtotal Commodity Related Charges per GJ	$6.770	$6.658	$6.756	$1.639	$1.647	$1.632	$8.409	$8.305	$8.388
17										
18										
19	Total Variable Cost per GJ	$9.100	$8.988	$9.086	$1.639	$1.647	$1.632	$10.739	$10.635	$10.718
20										
21	Revelstoke Variable Cost per GJ									
22	(Includes Rider 1)		$10.425			$0.000			$10.425	
23										
24										
25										

26 Note 1: The Revelstoke propane is unchanged from existing rates. The Rider 1 Propane Surcharge decrease of ($1.647)/GJ offsets the Gas Cost Recovery Charge increase of $1.647/GJ.

xx Note 1: The Rider 1 Propane Surcharge decrease of ($0.585)/GJ is the difference between the ($1.410)/GJ Revelstoke propane decrease
and the sum of the Gas Cost Recovery Charge decrease of ($0.437)/GJ and the Rider 6 GCRA decrease of ($0.388)/GJ.

BC GAS UTILITY LTD.
CALCULATION OF CUSTOMERS' RATES
EFFECTIVE APRIL 1, 2003
BCUC ORDER NO G-19-03

Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE Particulars	Existing March 1, 2003 Rates Lower Mainland	Inland	Columbia	Gas Cost Changes Lower Mainland	Inland	Columbia	April 1, 2003 Permanent Rates Lower Mainland	Inland	Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$115.43	$115.43	$115.43	$0.00	$0.00	$0.00	$115.43	$115.43	$115.43
3										
4	Delivery Charge per gigajoule	$1.861	$1.861	$1.861	$0.000	$0.000	$0.000	$1.861	$1.861	$1.861
5										
6	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.025	$0.025	$0.025	$0.000	$0.000	$0.000	$0.025	$0.025	$0.025
7	3 Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
8	5 RSAM	$0.134	$0.134	$0.134	$0.000	$0.000	$0.000	$0.134	$0.134	$0.134
9	Subtotal Delivery Margin Related Charges per GJ	$2.020	$2.020	$2.020	$0.000	$0.000	$0.000	$2.020	$2.020	$2.020
10										
11	Commodity Related Charges									
12	Gas Cost Recovery Charge per GJ	$5.916	$5.819	$5.913	$1.662	$1.663	$1.651	$7.578	$7.482	$7.564
13						1				
14	Riders: 1 Propane Surcharge (Revelstoke only)		$1.794			($1.663)			$0.131	
15	6 GCRA	$0.482	$0.482	$0.482	$0.000	$0.000	$0.000	$0.482	$0.482	$0.482
16	Subtotal Commodity Related Charges per GJ	$6.398	$6.301	$6.395	$1.662	$1.663	$1.651	$8.060	$7.964	$8.046
17										
18	Total Variable Cost per GJ	$8.418	$8.321	$8.415	$1.662	$1.663	$1.651	$10.080	$9.984	$10.066
19										
20										
21										
22	Revelstoke Variable Cost per GJ									
23	(Includes Rider 1)		$10.115			$0.000			$10.115	
24										
25										
26										

27 Note 1: The Revelstoke propane cost is unchanged from existing rates. The Rider 1 Propane Surcharge decrease of ($1.663)/GJ offsets the Gas Cost Recovery Charge increase of $1.663/GJ.

xxNote 1: The Rider 1 Propane Surcharge decrease of ($0.664)/GJ is the difference between the ($1.410)/GJ Revelstoke propane decrease
and the sum of the Gas Cost Recovery Charge decrease of ($0.442)/GJ and the Rider 6 GCRA decrease of ($0.304)/GJ.

Line No.	RATE SCHEDULE 4: SEASONAL SERVICE Particulars	Existing March 1, 2003 Rates Lower Mainland	 Inland	 Columbia	Gas Cost Changes Lower Mainland	 Inland	 Columbia	April 1, 2003 Permanent Rates Lower Mainland	 Inland	 Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Basic Charge per Month	$383.00	$383.00	$383.00	$0.00	$0.00	$0.00	$383.00	$383.00	$383.00
2										
3	Delivery Charge per gigajoule									
4	(a) Off-Peak Period	$0.664	$0.664	$0.664	$0.000	$0.000	$0.000	$0.664	$0.664	$0.664
5	(b) Extension Period	$1.341	$1.341	$1.341	$0.000	$0.000	$0.000	$1.341	$1.341	$1.341
6										
7	Gas Cost Recovery Charge per GJ									
8	(a) Off-Peak Period	$5.661	$5.580	$5.670	$1.678	$1.671	$1.660	$7.339	$7.251	$7.330
9	(b) Extension Period	$5.661	$5.580	$5.670	$1.678	$1.671	$1.660	$7.339	$7.251	$7.330
10										
11	Unauthorized Gas Charge	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
12	per GJ during peak period									
13										
14										
15	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16	3 Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
17	6 GCRA	$0.350	$0.350	$0.350	$0.000	$0.000	$0.000	$0.350	$0.350	$0.350
18										
19	Total Variable Cost per GJ between									
20	(a) Off-Peak Period	$6.675	$6.594	$6.684	$1.678	$1.671	$1.660	$8.353	$8.265	$8.344
21	(b) Extension Period	$7.352	$7.271	$7.361	$1.678	$1.671	$1.660	$9.030	$8.942	$9.021

BC GAS UTILITY LTD.
CALCULATION OF CUSTOMERS' RATES
EFFECTIVE APRIL 1, 2003
BCUC ORDER NO G-19-03

Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE	Existing March 1, 2003 Rates			Gas Cost Changes			April 1, 2003 Permanent Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Basic Charge per Month	$510.00	$510.00	$510.00	$0.00	$0.00	$0.00	$510.00	$510.00	$510.00
2										
3										
4	Demand Charge per GJ	$12.763	$12.763	$12.763	$0.000	$0.000	$0.000	$12.763	$12.763	$12.763
5										
6										
7	Delivery Charge per gigajoule	$0.517	$0.517	$0.517	$0.000	$0.000	$0.000	$0.517	$0.517	$0.517
8										
9										
10	Gas Cost Recovery Charge per GJ	$5.661	$5.580	$5.670	$1.678	$1.671	$1.660	$7.339	$7.251	$7.330
11										
12	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.013	$0.013	$0.013	$0.000	$0.000	$0.000	$0.013	$0.013	$0.013
13	3 Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	6 GCRA	$0.350	$0.350	$0.350	$0.000	$0.000	$0.000	$0.350	$0.350	$0.350
15										
16	Total Variable Cost per GJ	$6.541	$6.460	$6.550	$1.678	$1.671	$1.660	$8.219	$8.131	$8.210

Line No.	RATE SCHEDULE 6: NGV - STATIONS	Existing March 1, 2003 Rates			Gas Cost Changes			April 1, 2003 Permanent Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$53.80	$53.80	$53.80	$0.00	$0.00	$0.00	$53.80	$53.80	$53.80
2										
3										
4	Delivery Charge per gigajoule	$2.959	$2.959	$2.959	$0.000	$0.000	$0.000	$2.959	$2.959	$2.959
5										
6										
7	Gas Cost Recovery Charge per GJ	$5.361	$5.306	$5.306	$1.699	$1.685	$1.685	$7.060	$6.991	$6.991
8										
9	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.014	$0.014	$0.014	$0.000	$0.000	$0.000	$0.014	$0.014	$0.014
10	3 Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
11	6 GCRA	$0.174	$0.174	$0.174	$0.000	$0.000	$0.000	$0.174	$0.174	$0.174
12										
13										
14	Total Variable Cost per GJ	$8.508	$8.453	$8.453	$1.699	$1.685	$1.685	$10.207	$10.138	$10.138

RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	Existing March 1, 2003 Rates	Gas Cost Changes	April 1, 2003 Permanent Rates
	(1)	(2)	-3	-4
1	Lower Mainland Service Area			
2	Basic Charge per Month	$75.70	$0.00	$75.70
3	Minimum Charges	$125.00	$0.00	$125.00
4				
5				
6	Delivery Charge per gigajoule	$2.959	$0.000	$2.959
7				
8	Gas Cost Recovery Charge per GJ	$5.361	$1.699	$7.060
9				
10	Compression Charge per GJ	$5.280	$0.000	$5.280
11				
12	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.014	$0.000	$0.014
13	3 Earnings Sharing	$0.000	$0.000	$0.000
14	6 GCRA	$0.174	$0.000	$0.174
15				
16				
17	Total Variable Cost per GJ	$13.788	$1.699	$15.487

Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES	Existing March 1, 2003 Rates			Gas Cost Changes			April 1, 2003 Permanent Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$766.00	$766.00	$766.00	$0.00	$0.00	$0.00	$766.00	$766.00	$766.00
2										
3	Delivery Charge per gigajoule	$0.862	$0.862	$0.862	$0.000	$0.000	$0.000	$0.862	$0.862	$0.862
4										
5	Commodity Charge per GJ									
6	- Fixed Pricing	$5.661	$5.580	$5.670	$1.678	$1.671	$1.660	$7.339	$7.251	$7.330
7										
8	- Index Pricing	Sumas Daily	Sumas Daily	Sumas Daily				Sumas Daily	Sumas Daily	Sumas Daily
9		Price + the	Price + the	Price + the				Price + the	Price + the	Price + the
10		greater of	greater of	greater of				greater of	greater of	greater of
11		$0.05/GJ or Cost	$0.05/GJ or Cost	$0.05/GJ or Cost				$0.05/GJ or Cost	$0.05/GJ or Cost	$0.05/GJ or Cost
12										
13	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
14										
15										
16										
17	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.009	$0.009	$0.009	$0.000	$0.000	$0.000	$0.009	$0.009	$0.009
18	3 Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
19	6 GCRA	$0.350	$0.350	$0.350	$0.000	$0.000	$0.000	$0.350	$0.350	$0.350
20										
21										
22										
23	Total Variable Cost per GJ - Fixed Pricing Option	$6.882	$6.801	$6.891	$1.678	$1.671	$1.660	$8.560	$8.472	$8.551

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
EFFECTIVE JANUARY 1, 2004
BCUC ORDERS NO. G-80-03 AND G-82-03

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE Particulars	Existing 2003 Rates Lower Mainland	Inland	Columbia	2004 Revenue Requirement, Gas Cost and Rider Changes Lower Mainland	Inland	Columbia	January 1, 2004 Permanent Rates Lower Mainland	Inland	Columbia
	-1	(2)	-3	-4	-5	-6	-7	-8	-9	-10
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$10.31	$10.31	$10.31	$0.44	$0.44	$0.44	$10.75	$10.75	$10.75
3										
4	Delivery Charge per gigajoule	$2.579	$2.579	$2.579	$0.111	$0.111	$0.111	$2.690	$2.690	$2.690
5										
6	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.043	$0.043	$0.043	($0.043)	($0.043)	($0.043)	$0.000	$0.000	$0.000
7	3 Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
8	5 RSAM	$0.134	$0.134	$0.134	$0.061	$0.061	$0.061	$0.195	$0.195	$0.195
9	Subtotal Delivery Margin Related Charges per GJ	$2.756	$2.756	$2.756	$0.129	$0.129	$0.129	$2.885	$2.885	$2.885
10										
11	Commodity Related Charges									
12	Gas Cost Recovery Charge per GJ	$7.730	$7.628	$7.711	($0.563)	($0.568)	($0.515)	$7.167	$7.060	$7.196
13										
14	Riders: 1 Propane Surcharge (Revelstoke only)		$1.746			$1.138			$2.884	
15	6 GCRA	$0.570	$0.570	$0.570	($0.570)	($0.570)	($0.570)	$0.000	$0.000	$0.000
16	Subtotal Commodity Related Charges per GJ	$8.300	$8.198	$8.281	($1.133)	($1.138)	($1.085)	$7.167	$7.060	$7.196
17										
18	Total Variable Cost per GJ	$11.056	$10.954	$11.037	($1.004)	($1.009)	($0.956)	$10.052	$9.945	$10.081
19										
20	Revelstoke Variable Cost per GJ									
21	(Includes Rider 1)		$12.700			$0.129			$12.829	
22										
23										
24										

25 Note 1: The Revelstoke propane cost is unchanged from existing rates. The Rider 1 Propane Surcharge increase of $1.138/GJ offsets the Gas Cost Recovery Charge decrease of $0.568/GJ and the Rider 6 decrease of $0.570/GJ.

xx Note 1: The Rider 1 Propane Surcharge decrease of ($0.564)/GJ is the difference between the ($1.410)/GJ Revelstoke propane decrease and the sum of the Gas Cost Recovery Charge decrease of ($0.479)/GJ and the Rider 6 GCRA decrease of ($0.367)/GJ.

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Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE Particulars	Existing 2003 Rates Lower Mainland	Inland	Columbia	2004 Revenue Requirement, Gas Cost and Rider Changes Lower Mainland	Inland	Columbia	January 1, 2004 Permanent Rates Lower Mainland	Inland	Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$21.64	$21.64	$21.64	$0.93	$0.93	$0.93	$22.57	$22.57	$22.57
3										
4	Delivery Charge per gigajoule	$2.159	$2.159	$2.159	$0.093	$0.093	$0.093	$2.252	$2.252	$2.252
5										
6	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.037	$0.037	$0.037	($0.037)	($0.037)	($0.037)	$0.000	$0.000	$0.000
7	3 Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
8	5 RSAM	$0.134	$0.134	$0.134	$0.061	$0.061	$0.061	$0.195	$0.195	$0.195
9	Subtotal Delivery Margin Related Charges per GJ	$2.330	$2.330	$2.330	$0.117	$0.117	$0.117	$2.447	$2.447	$2.447
10										
11	Commodity Related Charges									
12	Gas Cost Recovery Charge per GJ	$7.799	$7.695	$7.778	($0.547)	($0.554)	($0.499)	$7.252	$7.141	$7.279
13										
14	Riders: 1 Propane Surcharge (Revelstoke only)		$0.548			$1.164			$1.712	
15	6 GCRA	$0.610	$0.610	$0.610	($0.610)	($0.610)	($0.610)	$0.000	$0.000	$0.000
16	Subtotal Commodity Related Charges per GJ	$8.409	$8.305	$8.388	($1.157)	($1.164)	($1.109)	$7.252	$7.141	$7.279
17										
18										
19	Total Variable Cost per GJ	$10.739	$10.635	$10.718	($1.040)	($1.047)	($0.992)	$9.699	$9.588	$9.726
20										
21	Revelstoke Variable Cost per GJ									
22	(Includes Rider 1)		$11.183			$0.117			$11.300	
23										
24										
25										
26	Note 1: The Revelstoke propane is unchanged from existing rates. The Rider 1 Propane Surcharge increase of $1.164/GJ offsets the Gas Cost Recovery Charge decrease of $0.554/GJ and Rider 6 decrease of $0.610/GJ.									

xx Note 1: The Rider 1 Propane Surcharge decrease of ($0.585)/GJ is the difference between the ($1.410)/GJ Revelstoke propane decrease and the sum of the Gas Cost Recovery Charge decrease of ($0.437)/GJ and the Rider 6 GCRA decrease of ($0.388)/GJ.

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Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE	Existing 2003 Rates			2004 Revenue Requirement, Gas Cost and Rider Changes			January 1, 2004 Permanent Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$115.43	$115.43	$115.43	$4.97	$4.97	$4.97	$120.40	$120.40	$120.40
3										
4	Delivery Charge per gigajoule	$1.861	$1.861	$1.861	$0.080	$0.080	$0.080	$1.941	$1.941	$1.941
5										
6	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.025	$0.025	$0.025	($0.025)	($0.025)	($0.025)	$0.000	$0.000	$0.000
7	3 Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
8	5 RSAM	$0.134	$0.134	$0.134	$0.061	$0.061	$0.061	$0.195	$0.195	$0.195
9	Subtotal Delivery Margin Related Charges per GJ	$2.020	$2.020	$2.020	$0.116	$0.116	$0.116	$2.136	$2.136	$2.136
10										
11	Commodity Related Charges									
12	Gas Cost Recovery Charge per GJ	$7.578	$7.482	$7.564	($0.586)	($0.587)	($0.537)	$6.992	$6.895	$7.027
13										
14	Riders: 1 Propane Surcharge (Revelstoke only)		$0.889			$1.069			$1.958	
15	6 GCRA	$0.482	$0.482	$0.482	($0.482)	($0.482)	($0.482)	$0.000	$0.000	$0.000
16	Subtotal Commodity Related Charges per GJ	$8.060	$7.964	$8.046	($1.068)	($1.069)	($1.019)	$6.992	$6.895	$7.027
17										
18	Total Variable Cost per GJ	$10.080	$9.984	$10.066	($0.952)	($0.953)	($0.903)	$9.128	$9.031	$9.163
19										
20										
21										
22	Revelstoke Variable Cost per GJ									
23	(Includes Rider 1)		$10.873			$0.116			$10.989	
24										
25										
26										
27	Note 1: The Revelstoke propane cost is unchanged from existing rates. The Rider 1 Propane Surcharge increase of $1.069/GJ offsets the Gas Cost Recovery Charge decrease of $0.587/GJ and Rider 6 decrease of $0.482/GJ.									

xxNote 1: The Rider 1 Propane Surcharge decrease of ($0.664)/GJ is the difference between the ($1.410)/GJ Revelstoke propane decrease and the sum of the Gas Cost Recovery Charge decrease of ($0.442)/GJ and the Rider 6 GCRA decrease of ($0.304)/GJ.

	RATE SCHEDULE 4: SEASONAL SERVICE		**Existing 2003 Rates**			**2004 Revenue Requirement, Gas Cost and Rider Changes**			**January 1, 2004 Permanent Rates**	
Line No.	Particulars		**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	-1		-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Basic Charge per Month		$383.00	$383.00	$383.00	$16.00	$16.00	$16.00	$399.00	$399.00	$399.00
2											
3	Delivery Charge per gigajoule										
4	(a) Off-Peak Period		$0.664	$0.664	$0.664	$0.029	$0.029	$0.029	$0.693	$0.693	$0.693
5	(b) Extension Period		$1.341	$1.341	$1.341	$0.058	$0.058	$0.058	$1.399	$1.399	$1.399
6											
7	Gas Cost Recovery Charge per GJ										
8	(a) Off-Peak Period		$7.339	$7.251	$7.330	($0.588)	($0.584)	($0.536)	$6.751	$6.667	$6.794
9	(b) Extension Period		$7.339	$7.251	$7.330	($0.588)	($0.584)	($0.536)	$6.751	$6.667	$6.794
10											
11	Unauthorized Gas Charge		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
12	per GJ during peak period										
13											
14											
15	Riders:	2 Jan - Feb 2003 Rate Increase Recovery	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16		3 Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
17		6 GCRA	$0.350	$0.350	$0.350	($0.350)	($0.350)	($0.350)	$0.000	$0.000	$0.000
18											
19	Total Variable Cost per GJ between										
20	(a) Off-Peak Period		$8.353	$8.265	$8.344	($0.909)	($0.905)	($0.857)	$7.444	$7.360	$7.487
21	(b) Extension Period		$9.030	$8.942	$9.021	($0.880)	($0.876)	($0.828)	$8.150	$8.066	$8.193

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Line No.	**RATE SCHEDULE 5 GENERAL FIRM SERVICE** Particulars	**Existing 2003 Rates** Lower Mainland	Inland	Columbia	**2004 Revenue Requirement, Gas Cost and Rider Changes** Lower Mainland	Inland	Columbia	**January 1, 2004 Permanent Rates** Lower Mainland	Inland	Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Basic Charge per Month	$510.00	$510.00	$510.00	$22.00	$22.00	$22.00	$532.00	$532.00	$532.00
2										
3										
4	Demand Charge per GJ	$12.763	$12.763	$12.763	$0.549	$0.549	$0.549	$13.312	$13.312	$13.312
5										
6										
7	Delivery Charge per gigajoule	$0.517	$0.517	$0.517	$0.022	$0.022	$0.022	$0.539	$0.539	$0.539
8										
9										
10	Gas Cost Recovery Charge per GJ	$7.339	$7.251	$7.330	($0.588)	($0.584)	($0.536)	$6.751	$6.667	$6.794
11										
12	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.013	$0.013	$0.013	($0.013)	($0.013)	($0.013)	$0.000	$0.000	$0.000
13	3 Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	6 GCRA	$0.350	$0.350	$0.350	($0.350)	($0.350)	($0.350)	$0.000	$0.000	$0.000
15										
16	Total Variable Cost per GJ	$8.219	$8.131	$8.210	($0.929)	($0.925)	($0.877)	$7.290	$7.206	$7.333

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Line No.	RATE SCHEDULE 6: NGV - STATIONS	Existing 2003 Rates			2004 Revenue Requirement, Gas Cost and Rider Changes			January 1, 2004 Permanent Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$53.80	$53.80	$53.80	$2.30	$2.30	$2.30	$56.10	$56.10	$56.10
2										
3										
4	Delivery Charge per gigajoule	$2.959	$2.959	$2.959	$0.127	$0.127	$0.127	$3.086	$3.086	$3.086
5										
6										
7	Gas Cost Recovery Charge per GJ	$7.060	$6.991	$6.991	($0.600)	($0.596)	($0.596)	$6.460	$6.395	$6.395
8										
9	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.014	$0.014	$0.014	($0.014)	($0.014)	($0.014)	$0.000	$0.000	$0.000
10	3 Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
11	6 GCRA	$0.174	$0.174	$0.174	($0.174)	($0.174)	($0.174)	$0.000	$0.000	$0.000
12										
13										
14	Total Variable Cost per GJ	$10.207	$10.138	$10.138	($0.661)	($0.657)	($0.657)	$9.546	$9.481	$9.481

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RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars		Existing Rates	2004 Revenue Requirement, Gas Cost and Rider Changes Changes	January 1, 2004 Permanent Rates
	(1)		(2)	-3	-4
1	Lower Mainland Service Area				
2	Basic Charge per Month		$75.70	$3.30	$79.00
3	Minimum Charges		$125.00	$0.00	$125.00
4					
5					
6	Delivery Charge per gigajoule		$2.959	$0.127	$3.086
7					
8	Gas Cost Recovery Charge per GJ		$7.060	($0.600)	$6.460
9					
10	Compression Charge per GJ		$5.280	$0.000	$5.280
11					
12	Riders:	2 Jan - Feb 2003 Rate Increase Recovery	$0.014	($0.014)	$0.000
13		3 Earnings Sharing	$0.000	$0.000	$0.000
14		6 GCRA	$0.174	($0.174)	$0.000
15					
16					
17	Total Variable Cost per GJ		$15.487	($0.661)	$14.826

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Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES	Existing 2003 Rates			2004 Revenue Requirement, Gas Cost and Rider Changes			January 1, 2004 Permanent Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$766.00	$766.00	$766.00	$33.00	$33.00	$33.00	$799.00	$799.00	$799.00
2										
3	Delivery Charge per gigajoule	$0.862	$0.862	$0.862	$0.037	$0.037	$0.037	$0.899	$0.899	$0.899
4										
5	Commodity Charge per GJ									
6	- Fixed Pricing	$7.339	$7.251	$7.330	($0.588)	($0.584)	($0.536)	$6.751	$6.667	$6.794
7										
8	- Index Pricing	Sumas Daily	Sumas Daily	Sumas Daily				Sumas Daily	Sumas Daily	Sumas Daily
9		Price + the	Price + the	Price + the				Price + the	Price + the	Price + the
10		greater of	greater of	greater of				greater of	greater of	greater of
11		$0.05/GJ or Cost	$0.05/GJ or Cost	$0.05/GJ or Cost				$0.05/GJ or Cost	$0.05/GJ or Cost	$0.05/GJ or Cost
12										
13	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
14										
15										
16										
17	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.009	$0.009	$0.009	($0.009)	($0.009)	($0.009)	$0.000	$0.000	$0.000
18	3 Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
19	6 GCRA	$0.350	$0.350	$0.350	($0.350)	($0.350)	($0.350)	$0.000	$0.000	$0.000
20										
21										
22										
23	Total Variable Cost per GJ - Fixed Pricing Option	$8.560	$8.472	$8.551	($0.910)	($0.906)	($0.858)	$7.650	$7.566	$7.693

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Line No.	RATE SCHEDULE 22: LARGE INDUSTRIAL T-SERVICE	Existing 2003 Rates			2004 Revenue Requirement and Rider Changes			January 1, 2004 Permanent Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$3,192.00	$3,192.00	$3,192.00	$137.00	$137.00	$137.00	$3,329.00	$3,329.00	$3,329.00
2										
3	Delivery Charge (Interr. MTQ)	$0.639	$0.639	$0.639	$0.027	$0.027	$0.027	$0.666	$0.666	$0.666
4										
5										
6	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
7										
8										
9	Demand Surcharge per GJ	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00	$17.00	$17.00	$17.00
10										
11	Balancing Service per GJ									
12	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.30	n/a	$0.000	$0.000	$0.000	$0.30	$0.30	n/a
13	(b) between and including Nov. 1 and Mar. 31	$1.10	$1.10	n/a	$0.000	$0.000	$0.000	$1.10	$1.10	n/a
14										
15										
16	Charges per GJ for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17										
18										
19	Administration Charge	$70.00	$70.00	$70.00	$0.00	$0.00	$0.00	$70.00	$70.00	$70.00
20										
21	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.007	$0.007	$0.007	($0.007)	($0.007)	($0.007)	$0.000	$0.000	$0.000
22	3 Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
23										
24										
25										
26										
27	Total Variable Cost per GJ - Fixed Pricing Option	$0.646	$0.646	$0.646	$0.020	$0.020	$0.020	$0.666	$0.666	$0.666

RATE SCHEDULE 22A:
LARGE INDUSTRIAL T-SERVICE

Line No.	Particulars	Existing Rates	2004 Revenue Requirement and Rider Changes Changes	January 1, 2004 Permanent Rates
	(1)	(2)	(3)	(4)
1	Basic Charge per Month	$4,191.00	$180.00	$4,371.00
2				
3	Delivery Charge per GJ - Firm			
4	(a) Firm DTQ	$10.248	$0.441	$10.689
5	(b) Firm MTQ	$0.072	$0.003	$0.075
6				
7	Delivery Charge per GJ - Interr MTQ	$0.819	$0.035	$0.854
8				
9	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
10				
11				
12	Demand Surchage per GJ	$17.00	$0.00	$17.00
13				
14	Balancing Service per GJ			
15	(a) between and including Apr. 1 and Oct. 31	$0.300	$0.00	$0.300
16	(b) between and including Nov. 1 and Mar. 31	$1.100	$0.00	$1.100
17				
18	Charges per GJ for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
19				
20				
21	Replacement Gas	Sumas Daily Price		Sumas Daily Price
22		plus 20 Percent		plus 20 Percent
23				
24	Administration Charge	$70.00	$0.00	$70.00
25				
26	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.006	($0.006)	$0.000
27	3 Earnings Sharing	$0.000	$0.000	$0.000
28				
29	Total Variable Cost per GJ			
30	(a) Firm MTQ	$0.078	($0.003)	$0.075
31				
32	(b) Interruptible MTQ	$0.825	$0.029	$0.854

Line No.	**RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE** Particulars	**Existing 2003 Rates** Columbia Except Elkview	Elkview Coal	**2004 Revenue Requirement and Rider Changes** Columbia Except Elkview	Elkview Coal	**January 1, 2004 Permanent Rates** Columbia Except Elkview	Elkview Coal
	(1)	-2	(3)	(4)	-5	-6	-7
1	Basic Charge per Month	$3,952.00	$3,952.00	$170.00	$170.00	$4,122.00	$4,122.00
2							
3	Delivery Charge per GJ - Firm						
4	(a) Firm DTQ	$6.530	$1.482	$0.281	$0.064	$6.811	$1.546
5	(b) Firm MTQ	$0.070	$0.070	$0.003	$0.003	$0.073	$0.073
6							
7	Delivery Charge per GJ - Interr MTQ						
8	(a) between and including Apr. 1 and Oct. 31	$0.650	$0.162	$0.028	$0.007	$0.678	$0.169
9	(b) between and including Nov. 1 and Mar. 31	$0.938	$0.233	$0.040	$0.010	$0.978	$0.243
10							
11	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
12							
13							
14	Demand Surcharge per GJ	$17.00	$17.00	$0.00	$0.00	$17.00	$17.00
15							
16	Charges per GJ for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
17							
18							
19							
20	Administration Charge	$70.00	$70.00	$0.00	$0.00	$70.00	$70.00
21							
22	Riders: Jan - Feb 2003 Rate Increase Recovery	$0.005	$0.003	($0.005)	($0.003)	$0.000	$0.000
23	Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
24							
25							
26							
27							
28							
29							
30	Total Variable Cost per GJ						
31	(a) Firm MTQ	$0.075	$0.073	($0.002)	$0.000	$0.073	$0.073
32	(b) Interruptible MTQ - Summer	$0.655	$0.165	$0.023	$0.004	$0.678	$0.169
33	- Winter	$0.943	$0.236	$0.035	$0.007	$0.978	$0.243
34							

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EFFECTIVE JANUARY 1, 2004
BCUC ORDER NO. G-80-03

Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE Particulars	Existing 2003 Rates Lower Mainland	Inland	Columbia	2004 Revenue Requirement and Rider Changes Lower Mainland	Inland	Columbia	January 1, 2004 Permanent Rates Lower Mainland	Inland	Columbia
	-1	(2)	-3	-4	-5	-6	-7	-8	-9	-10
1	Basic Charge per Month	$115.43	$115.43	$115.43	$4.97	$4.97	$4.97	$120.40	$120.40	$120.40
2										
3										
4	Delivery Charge per GJ	$1.861	$1.861	$1.861	$0.080	$0.080	$0.080	$1.941	$1.941	$1.941
5										
6	Administration Charge	$70.00	$70.00	$70.00	$0.00	$0.00	$0.00	$70.00	$70.00	$70.00
7										
8	Sales									
9	(a) Charge per GJ for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per GJ for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per GJ for UOR Gas									
13										
14	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.025	$0.025	$0.025	($0.025)	($0.025)	($0.025)	$0.000	$0.000	$0.000
15	3 Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16	5 RSAM	$0.134	$0.134	$0.134	$0.061	$0.061	$0.061	$0.195	$0.195	$0.195
17										
18										
19										
20	Total Variable Cost per GJ	$2.020	$2.020	$2.020	$0.116	$0.116	$0.116	$2.136	$2.136	$2.136

Line No.	RATE SCHEDULE 25 GENERAL FIRM T-SERVICE Particulars	Existing 2003 Rates Lower Mainland	Existing 2003 Rates Inland	Existing 2003 Rates Columbia	2004 Revenue Requirement and Rider Changes Lower Mainland	2004 Revenue Requirement and Rider Changes Inland	2004 Revenue Requirement and Rider Changes Columbia	January 1, 2004 Permanent Rates Lower Mainland	January 1, 2004 Permanent Rates Inland	January 1, 2004 Permanent Rates Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$510.00	$510.00	$510.00	$22.00	$22.00	$22.00	$532.00	$532.00	$532.00
2										
3	Demand Charge per GJ	$12.763	$12.763	$12.763	$0.549	$0.549	$0.549	$13.312	$13.312	$13.312
4										
5										
6	Delivery Charge (Interr. MTQ)	$0.517	$0.517	$0.517	$0.022	$0.022	$0.022	$0.539	$0.539	$0.539
7										
8	Administration Charge	$70.00	$70.00	$70.00	$0.00	$0.00	$0.00	$70.00	$70.00	$70.00
9										
10	Sales									
11	(a) Charge per GJ for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per GJ for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per GJ for UOR Gas									
15										
16										
17										
18	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.013	$0.013	$0.013	($0.013)	($0.013)	($0.013)	$0.000	$0.000	$0.000
19	3 Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
20										
21										
22	Total Variable Cost per GJ - Fixed Pricing Option	$0.530	$0.530	$0.530	$0.009	$0.009	$0.009	$0.539	$0.539	$0.539

Line No.	RATE SCHEDULE 27: INTERRUPTIBLE T-SERVICE Particulars	Existing 2003 Rates Lower Mainland	Inland	Columbia	2004 Revenue Requirement and Rider Changes Lower Mainland	Inland	Columbia	January 1, 2004 Permanent Rates Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$766.00	$766.00	$766.00	$33.00	$33.00	$33.00	$799.00	$799.00	$799.00
2										
3										
4	Delivery Charge (Interr. MTQ)	$0.862	$0.862	$0.862	$0.037	$0.037	$0.037	$0.899	$0.899	$0.899
5										
6	Administration Charge	$70.00	$70.00	$70.00	$0.00	$0.00	$0.00	$70.00	$70.00	$70.00
7										
8	Sales									
9	(a) Charge per GJ for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per GJ for Backstopping Gas									
11	(c) Charge per GJ for UOR Gas									
12										
13	Riders: 2 Jan - Feb 2003 Rate Increase Recovery	$0.009	$0.009	$0.009	($0.009)	($0.009)	($0.009)	$0.000	$0.000	$0.000
14	3 Earnings Sharing	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15										
16										
17	Total Variable Cost per GJ - Fixed Pricing Option	$0.871	$0.871	$0.871	$0.028	$0.028	$0.028	$0.899	$0.899	$0.899

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Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE	Existing 2004 Rates			2005 Revenue Requirement, Gas Cost and Rider Changes			January 1, 2005 Approved Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	-1	(2)	-3	-4	-5	-6	-7	-8	-9	-10
1	Delivery Margin Related Charges				$0.05					
2	Basic Charge per Month	$10.75	$10.75	$10.75	($0.05)	($0.05)	($0.05)	$10.70	$10.70	$10.70
3										
4	Delivery Charge per gigajoule	$2.690	$2.690	$2.690	($0.013)	($0.013)	($0.013)	$2.677	$2.677	$2.677
5										
6	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	3 ESM	$0.000	$0.000	$0.000	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002
8	5 RSAM	$0.195	$0.195	$0.195	($0.052)	($0.052)	($0.052)	$0.143	$0.143	$0.143
9	Subtotal Delivery Margin Related Charges per GJ	$2.885	$2.885	$2.885	($0.063)	($0.063)	($0.063)	$2.822	$2.822	$2.822
10										
11	Commodity Related Charges									
12	Commodity Gas Cost Recovery Charge per GJ	$7.005	$7.005	$7.005	$0.000	$0.000	$0.000	$7.005	$7.005	$7.005
13	Midstream Gas Cost Recovery Charge per GJ	0.649	0.542	0.678	$0.000	$0.000	$0.000	0.649	0.542	0.678
14	Riders: 1 Propane Surcharge (Revelstoke only)		$4.214			$0.000			$4.214	
15	6 MCRA				$0.000	$0.000	$0.000			
16	9 Stable Rate Recovery	0.000	0.000	0.000	$0.006	$0.006	$0.006	0.006	0.006	0.006
17	Subtotal Commodity Related Charges per GJ	$7.654	$7.547	$7.683	$0.006	$0.006	$0.006	$7.660	$7.553	$7.689
18										
19	Total Variable Cost per GJ	$10.539	$10.432	$10.568	($0.057)	($0.057)	($0.057)	$10.482	$10.375	$10.511
20										
21	Revelstoke Variable Cost per GJ									
22	(Includes Rider 1, Excludes Rider 9)		$14.646			($0.063)			$14.583	
23										
24										
25										

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Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE	Existing 2004 Rates			2005 Revenue Requirement, Gas Cost and Rider Changes			January 1, 2005 Approved Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$22.57	$22.57	$22.57	($0.11)	($0.11)	($0.11)	$22.46	$22.46	$22.46
3										
4	Delivery Charge per gigajoule	$2.252	$2.252	$2.252	($0.011)	($0.011)	($0.011)	$2.241	$2.241	$2.241
5										
6	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	3 ESM	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001
8	5 RSAM	$0.195	$0.195	$0.195	($0.052)	($0.052)	($0.052)	$0.143	$0.143	$0.143
9	Subtotal Delivery Margin Related Charges per GJ	$2.447	$2.447	$2.447	($0.062)	($0.062)	($0.062)	$2.385	$2.385	$2.385
10										
11	Commodity Related Charges									
12	Commodity Gas Cost Recovery Charge per GJ	$7.038	$7.038	$7.038	$0.000	$0.000	$0.000	$7.038	$7.038	$7.038
13	Midstream Gas Cost Recovery Charge per GJ	$0.704	$0.593	$0.731				$0.704	$0.593	$0.731
14	Riders: 1 Propane Surcharge (Revelstoke only)		$3.039			$0.000			$3.039	
15	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16	8 Unbundling Recovery	$0.000	$0.000	$0.000	$0.056	$0.056	$0.056	0.056	0.056	0.056
17	Subtotal Commodity Related Charges per GJ	$7.742	$7.631	$7.769	$0.056	$0.056	$0.056	$7.798	$7.687	$7.825
18										
19										
20	Total Variable Cost per GJ	$10.189	$10.078	$10.216	($0.006)	($0.006)	($0.006)	$10.183	$10.072	$10.210
21										
22	Revelstoke Variable Cost per GJ									
23	(Includes Rider 1, Excludes Rider 8)		$13.117			($0.062)			$13.055	
24										
25										
26										

Tariff2k5Jan1Dec15DecisionY04

Rate3

TERASEN GAS INC.
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TAB 2
PAGE 3
SCHEDULE 3

Line No.	**RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE** Particulars	**Existing 2004 Rates** Lower Mainland	Inland	Columbia	**2005 Revenue Requirement, Gas Cost and Rider Changes** Lower Mainland	Inland	Columbia	**January 1, 2005 Approved Rates** Lower Mainland	Inland	Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$120.40	$120.40	$120.40	($0.57)	($0.57)	($0.57)	$119.83	$119.83	$119.83
3										
4	Delivery Charge per gigajoule	$1.941	$1.941	$1.941	($0.009)	($0.009)	($0.009)	$1.932	$1.932	$1.932
5										
6	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	3 ESM	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001
8	5 RSAM	$0.195	$0.195	$0.195	($0.052)	($0.052)	($0.052)	$0.143	$0.143	$0.143
9	Subtotal Delivery Margin Related Charges per GJ	$2.136	$2.136	$2.136	($0.060)	($0.060)	($0.060)	$2.076	$2.076	$2.076
10										
11	Commodity Related Charges									
12	Commodity Cost Recovery	$6.938	$6.938	$6.938	$0.000	$0.000	$0.000	$6.938	$6.938	$6.938
13	Midstream Cost Recovery	$0.537	$0.440	$0.572				$0.537	$0.440	$0.572
14	Riders: 1 Propane Surcharge (Revelstoke only)		$3.292			$0.000			$3.292	
15	6 MCRA		$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16	8 Unbundling Recovery	$0.000	$0.000	$0.000	$0.056	$0.056	$0.056	0.056	0.056	0.056
17	Subtotal Commodity Related Charges per GJ	$7.475	$7.378	$7.510	$0.056	$0.056	$0.056	$7.531	$7.434	$7.566
18										
19	Total Variable Cost per GJ	$9.611	$9.514	$9.646	($0.004)	($0.004)	($0.004)	$9.607	$9.510	$9.642
20										
21										
22										
23	Revelstoke Variable Cost per GJ									
24	(Includes Rider 1, Excludes Rider 8)		$12.806			($0.060)			$12.746	
25										
26										
27										

TERASEN GAS INC.
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Line No.	RATE SCHEDULE 4: SEASONAL SERVICE Particulars	Existing 2004 Rates Lower Mainland	Inland	Columbia	2005 Revenue Requirement, Gas Cost and Rider Changes Lower Mainland	Inland	Columbia	January 1, 2005 Approved Rates Lower Mainland	Inland	Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Basic Charge per Month	$399.00	$399.00	$399.00	($2.00)	($2.00)	($2.00)	$397.00	$397.00	$397.00
2										
3	Delivery Charge per gigajoule									
4	(a) Off-Peak Period	$0.693	$0.693	$0.693	($0.003)	($0.003)	($0.003)	$0.690	$0.690	$0.690
5	(b) Extension Period	$1.399	$1.399	$1.399	($0.007)	($0.007)	($0.007)	$1.392	$1.392	$1.392
6										
7	Gas Cost Recovery Charge per GJ									
8	(a) Off-Peak Period									
9	Commodity Cost Recovery	$6.847	$6.847	$6.847	$0.000	$0.000	$0.000	$6.847	$6.847	$6.847
10	Midstream Cost Recovery	$0.382	$0.298	$0.425	$0.000	$0.000	$0.000	$0.382	$0.298	$0.425
11		$7.229	$7.145	$7.272	$0.000	$0.000	$0.000	$7.229	$7.145	$7.272
12	(b) Extension Period									
13	Commodity Cost Recovery	$6.847	$6.847	$6.847	$0.000	$0.000	$0.000	$6.847	$6.847	$6.847
14	Midstream Cost Recovery	$0.382	$0.298	$0.425	$0.000	$0.000	$0.000	$0.382	$0.298	$0.425
15		$7.229	$7.145	$7.272	$0.000	$0.000	$0.000	$7.229	$7.145	$7.272
16	Unauthorized Gas Charge	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17	per GJ during peak period									
18										
19										
20	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
21	3 ESM	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
22	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
23										
24	Total Variable Cost per GJ between									
25	(a) Off-Peak Period	$7.922	$7.838	$7.965	($0.003)	($0.003)	($0.003)	$7.919	$7.835	$7.962
26	(b) Extension Period	$8.628	$8.544	$8.671	($0.007)	($0.007)	($0.007)	$8.621	$8.537	$8.664

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Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE Particulars	Existing 2004 Rates Lower Mainland	Existing 2004 Rates Inland	Existing 2004 Rates Columbia	2005 Revenue Requirement, Gas Cost and Rider Changes Lower Mainland	2005 Revenue Requirement, Gas Cost and Rider Changes Inland	2005 Revenue Requirement, Gas Cost and Rider Changes Columbia	January 1, 2005 Approved Rates Lower Mainland	January 1, 2005 Approved Rates Inland	January 1, 2005 Approved Rates Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Basic Charge per Month	$532.00	$532.00	$532.00	($2.00)	($2.00)	($2.00)	$530.00	$530.00	$530.00
2										
3										
4	Demand Charge per GJ	$13.312	$13.312	$13.312	($0.062)	($0.062)	($0.062)	$13.250	$13.250	$13.250
5										
6										
7	Delivery Charge per gigajoule	$0.539	$0.539	$0.539	($0.003)	($0.003)	($0.003)	$0.536	$0.536	$0.536
8										
9	Commodity Related Charges									
10	Commodity Cost Recovery	$6.847	$6.847	$6.847	$0.000	$0.000	$0.000	$6.847	$6.847	$6.847
11	Midstream Cost Recovery	$0.382	$0.298	$0.425	$0.000	$0.000	$0.000	$0.382	$0.298	$0.425
12		7.229	7.145	7.272	0.000	0.000	0.000	7.229	7.145	7.272
13	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	3 ESM	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001
15	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16										
17	Total Variable Cost per GJ	$7.768	$7.684	$7.811	($0.002)	($0.002)	($0.002)	$7.766	$7.682	$7.809

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Line No.	RATE SCHEDULE 6: NGV - STATIONS	Existing 2004 Rates			2005 Revenue Requirement, Gas Cost and Rider Changes			January 1, 2005 Approved Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
					$0.26					
1	Basic Charge per Month	$56.10	$56.10	$56.10	($0.30)	($0.30)	($0.30)	$55.80	$55.80	$55.80
2					-0.5348%					
3										
4	Delivery Charge per gigajoule	$3.086	$3.086	$3.086	($0.014)	($0.014)	($0.014)	$3.072	$3.072	$3.072
5										
6	Commodity Related Charges									
7	Commodity Cost Recovery	$6.736	$6.736	$6.736	$0.000	$0.000	$0.000	$6.736	$6.736	$6.736
8	Midstream Cost Recovery	$0.199	$0.134	$0.134	$0.000	$0.000	$0.000	$0.199	$0.134	$0.134
9		6.935	6.870	6.870	0.000	0.000	0.000	6.935	6.870	6.870
10	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
11	3 ESM	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
12	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
13										
14										
15	Total Variable Cost per GJ	$10.021	$9.956	$9.956	($0.014)	($0.014)	($0.014)	$10.007	$9.942	$9.942

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RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	Existing Rates	2005 Revenue Requirement, Gas Cost and Rider Changes Changes	January 1, 2005 Permanent Rates
	(1)	(2)	-3	-4
1	Lower Mainland Service Area			
2	Basic Charge per Month	$79.00	($0.40)	$78.60
3	Minimum Charges	$125.00	$0.00	$125.00
4				
5	Delivery Charge per gigajoule	$3.086	($0.014)	$3.072
6	Commodity Related Charges			
7	Commodity Cost Recovery	$6.736	$0.000	$6.736
8	Midstream Cost Recovery	$0.199	$0.000	$0.199
9		$6.935	$0.000	$6.935
10	Compression Charge per GJ	$5.280	$0.000	$5.280
11				
12	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000
13	3 ESM	$0.000	$0.000	$0.000
14	6 MCRA	$0.000	$0.000	$0.000
15				
16				
17	Total Variable Cost per GJ	$15.301	($0.014)	$15.287

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Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES	Existing 2004 Rates			2005 Revenue Requirement, Gas Cost and Rider Changes			January 1, 2005 Approved Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
					$3.76					
1	Basic Charge per Month	$799.00	$799.00	$799.00	($4.00)	($4.00)	($4.00)	$795.00	$795.00	$795.00
2					-0.5006%					
3	Delivery Charge per gigajoule	$0.899	$0.899	$0.899	($0.004)	($0.004)	($0.004)	$0.895	$0.895	$0.895
4										
5	Commodity Related Charges per GJ									
6										
7	Commodity Cost Recovery	$6.847	$6.847	$6.847	$0.000	$0.000	$0.000	$6.847	$6.847	$6.847
8	Midstream Cost Recovery	$0.382	$0.298	$0.425	$0.000	$0.000	$0.000	$0.382	$0.298	$0.425
9		$7.229	$7.145	$7.272	$0.000	$0.000	$0.000	$7.229	$7.145	$7.272
10										
11										
12										
13										
14										
15	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
16										
17										
18										
19	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
20	3 ESM	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001
21	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
22										
23										
24										
25	Total Variable Cost per GJ	$8.128	$8.044	$8.171	($0.003)	($0.003)	($0.003)	$8.125	$8.041	$8.168

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
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	RATE SCHEDULE 22: LARGE INDUSTRIAL T-SERVICE	**Existing 2004 Rates**			**2005 Revenue Requirement and Rider Changes**			**January 1, 2005 Approved Rates**		
Line No.	Particulars	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$3,329.00	$3,329.00	$3,329.00	($16.00)	($16.00)	($16.00)	$3,313.00	$3,313.00	$3,313.00
2										
3	Delivery Charge (Interr. MTQ)	$0.666	$0.666	$0.666	($0.003)	($0.003)	($0.003)	$0.663	$0.663	$0.663
4										
5										
6	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
7										
8										
9	Demand Surcharge per GJ	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00	$17.00	$17.00	$17.00
10										
11	Balancing Service per GJ									
12	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.30	n/a	$0.000	$0.000	$0.000	$0.30	$0.30	n/a
13	(b) between and including Nov. 1 and Mar. 31	$1.10	$1.10	n/a	$0.000	$0.000	$0.000	$1.10	$1.10	n/a
14										
15										
16	Charges per GJ for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17										
18										
19	Administration Charge	$70.00	$70.00	$70.00	$0.00	$0.00	$0.00	$70.00	$70.00	$70.00
20										
21	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
22	3 ESM	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
23										
24										
25										
26										
27	Total Variable Cost per GJ	$0.666	$0.666	$0.666	($0.003)	($0.003)	($0.003)	$0.663	$0.663	$0.663

RATE SCHEDULE 22A:
LARGE INDUSTRIAL T-SERVICE

Line No.	Particulars	**Existing Rates**	**2005 Revenue Requirement and Rider Changes Changes**	**January 1, 2005 Permanent Rates**
	(1)	(2)	(3)	(4)
1	Basic Charge per Month	$4,371.00	($21.00)	$4,350.00
2				
3	Delivery Charge per GJ - Firm			
4	(a) Firm DTQ	$10.689	($0.050)	$10.639
5	(b) Firm MTQ	$0.075	$0.000	$0.075
6				
7	Delivery Charge per GJ - Interr MTQ	$0.854	($0.004)	$0.850
8				
9	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
10				
11				
12	Demand Surchage per GJ	$17.00	$0.00	$17.00
13				
14	Balancing Service per GJ			
15	(a) between and including Apr. 1 and Oct. 31	$0.300	$0.00	$0.300
16	(b) between and including Nov. 1 and Mar. 31	$1.100	$0.00	$1.100
17				
18	Charges per GJ for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
19				
20				
21	Replacement Gas	Sumas Daily Price		Sumas Daily Price
22		plus 20 Percent		plus 20 Percent
23				
24	Administration Charge	$70.00	$0.00	$70.00
25				
26	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000
27	3 ESM	$0.000	$0.000	$0.000
28				
29	Total Variable Cost per GJ			
30	(a) Firm MTQ	$0.075	$0.000	$0.075
31				
32	(b) Interruptible MTQ	$0.854	($0.004)	$0.850

Line No.	RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE	Existing 2004 Rates		2005 Revenue Requirement and Rider Changes		January 1, 2005 Approved Rates	
	Particulars	Columbia Except Elkview	Elkview Coal	Columbia Except Elkview	Elkview Coal	Columbia Except Elkview	Elkview Coal
	(1)	-2	(3)	(4)	-5	-6	-7
1	Basic Charge per Month	$4,122.00	$4,122.00	($19.00)	($19.00)	$4,103.00	$4,103.00
2							
3	Delivery Charge per GJ - Firm						
4	(a) Firm DTQ	$6.811	$1.546	($0.032)	($0.007)	$6.779	$1.539
5	(b) Firm MTQ	$0.073	$0.073	$0.000	$0.000	$0.073	$0.073
6							
7	Delivery Charge per GJ - Interr MTQ						
8	(a) between and including Apr. 1 and Oct. 31	$0.678	$0.169	($0.003)	($0.001)	$0.675	$0.168
9	(b) between and including Nov. 1 and Mar. 31	$0.978	$0.243	($0.005)	($0.001)	$0.973	$0.242
10							
11	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
12							
13							
14	Demand Surcharge per GJ	$17.00	$17.00	$0.00	$0.00	$17.00	$17.00
15							
16	Charges per GJ for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
17							
18							
19							
20	Administration Charge	$70.00	$70.00	$0.00	$0.00	$70.00	$70.00
21							
22	Riders: Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
23	ESM	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
24							
25							
26							
27							
28							
29							
30	Total Variable Cost per GJ						
31	(a) Firm MTQ	$0.073	$0.073	$0.000	$0.000	$0.073	$0.073
32	(b) Interruptible MTQ - Summer	$0.678	$0.169	($0.003)	($0.001)	$0.675	$0.168
33	- Winter	$0.978	$0.243	($0.005)	($0.001)	$0.973	$0.242
34							

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
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Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE Particulars	Existing 2004 Rates Lower Mainland	Existing 2004 Rates Inland	Existing 2004 Rates Columbia	2005 Revenue Requirement and Rider Changes Lower Mainland	2005 Revenue Requirement and Rider Changes Inland	2005 Revenue Requirement and Rider Changes Columbia	January 1, 2005 Approved Rates Lower Mainland	January 1, 2005 Approved Rates Inland	January 1, 2005 Approved Rates Columbia
	-1	(2)	-3	-4	-5	-6	-7	-8	-9	-10
1	Basic Charge per Month	$120.40	$120.40	$120.40	($0.57)	($0.57)	($0.57)	$119.83	$119.83	$119.83
2										
3										
4	Delivery Charge per GJ	$1.941	$1.941	$1.941	($0.009)	($0.009)	($0.009)	$1.932	$1.932	$1.932
5										
6	Administration Charge	$70.00	$70.00	$70.00	$0.00	$0.00	$0.00	$70.00	$70.00	$70.00
7										
8	Sales									
9	(a) Charge per GJ for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per GJ for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per GJ for UOR Gas									
13										
14	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	3 ESM	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001
16	5 RSAM	$0.195	$0.195	$0.195	($0.052)	($0.052)	($0.052)	$0.143	$0.143	$0.143
17										
18										
19										
20	Total Variable Cost per GJ	$2.136	$2.136	$2.136	($0.060)	($0.060)	($0.060)	$2.076	$2.076	$2.076

Line No.	RATE SCHEDULE 25 GENERAL FIRM T-SERVICE	Existing 2004 Rates			2005 Revenue Requirement and Rider Changes			January 1, 2005 Approved Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$532.00	$532.00	$532.00	($2.00)	($2.00)	($2.00)	$530.00	$530.00	$530.00
2										
3	Demand Charge per GJ	$13.312	$13.312	$13.312	($0.062)	($0.062)	($0.062)	$13.250	$13.250	$13.250
4										
5										
6	Delivery Charge (Interr. MTQ)	$0.539	$0.539	$0.539	($0.003)	($0.003)	($0.003)	$0.536	$0.536	$0.536
7										
8	Administration Charge	$70.00	$70.00	$70.00	$0.00	$0.00	$0.00	$70.00	$70.00	$70.00
9										
10	Sales									
11	(a) Charge per GJ for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per GJ for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per GJ for UOR Gas									
15										
16										
17										
18	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
19	3 ESM	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001
20										
21										
22	Total Variable Cost per GJ	$0.539	$0.539	$0.539	($0.002)	($0.002)	($0.002)	$0.537	$0.537	$0.537

Line No.	RATE SCHEDULE 27: INTERRUPTIBLE T-SERVICE Particulars	Existing 2004 Rates Lower Mainland	Inland	Columbia	2005 Revenue Requirement and Rider Changes Lower Mainland	Inland	Columbia	January 1, 2005 Approved Rates Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$799.00	$799.00	$799.00	($4.00)	($4.00)	($4.00)	$795.00	$795.00	$795.00
2										
3										
4	Delivery Charge (Interr. MTQ)	$0.899	$0.899	$0.899	($0.004)	($0.004)	($0.004)	$0.895	$0.895	$0.895
5										
6	Administration Charge	$70.00	$70.00	$70.00	$0.00	$0.00	$0.00	$70.00	$70.00	$70.00
7										
8	Sales									
9	(a) Charge per GJ for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per GJ for Backstopping Gas									
11	(c) Charge per GJ for UOR Gas									
12										
13	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	3 ESM	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001
15										
16										
17	Total Variable Cost per GJ	$0.899	$0.899	$0.899	($0.003)	($0.003)	($0.003)	$0.896	$0.896	$0.896

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
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	RATE SCHEDULE 1: RESIDENTIAL SERVICE	**Existing 2005 Rates**			**2005 Gas Cost Changes**			**July 1, 2005 Approved Rates**		
Line No.	Particulars	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	-1	(2)	-3	-4	-5	-6	-7	-8	-9	-10
1	Delivery Margin Related Charges				$0.00					
2	Basic Charge per Month	$10.70	$10.70	$10.70	$0.00	$0.00	$0.00	$10.70	$10.70	$10.70
3										
4	Delivery Charge per gigajoule	$2.677	$2.677	$2.677	$0.000	$0.000	$0.000	$2.677	$2.677	$2.677
5										
6	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	3 ESM	$0.002	$0.002	$0.002	$0.000	$0.000	$0.000	$0.002	$0.002	$0.002
8	5 RSAM	$0.143	$0.143	$0.143	$0.000	$0.000	$0.000	$0.143	$0.143	$0.143
9	Subtotal Delivery Margin Related Charges per GJ	$2.822	$2.822	$2.822	$0.000	$0.000	$0.000	$2.822	$2.822	$2.822
10										
11	Commodity Related Charges									
12	Commodity Gas Cost Recovery Charge per GJ	$7.005	$7.005	$7.005	$0.653	$0.653	$0.653	$7.658	$7.658	$7.658
13	Midstream Gas Cost Recovery Charge per GJ	0.649	0.542	0.678	$0.000	$0.000	$0.000	0.649	0.542	0.678
14	Riders: 1 Propane Surcharge (Revelstoke only)		$5.242			$0.000			$5.242	
15	6 MCRA				$0.000	$0.000	$0.000			
16	9 Stable Rate Recovery	0.006	0.006	0.006	$0.000	$0.000	$0.000	0.006	0.006	0.006
17	Subtotal Commodity Related Charges per GJ	$7.660	$7.553	$7.689	$0.653	$0.653	$0.653	$8.313	$8.206	$8.342
18										
19	Total Variable Cost per GJ	$10.482	$10.375	$10.511	$0.653	$0.653	$0.653	$11.135	$11.028	$11.164
20										
21	Revelstoke Variable Cost per GJ									
22	(Includes Rider 1, Excludes Rider 9)		$15.611			$0.653			$16.264	
23										
24										
25										

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Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE	Existing 2005 Rates			2005 Gas Cost Changes			July 1, 2005 Approved Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$22.46	$22.46	$22.46	$0.00	$0.00	$0.00	$22.46	$22.46	$22.46
3										
4	Delivery Charge per gigajoule	$2.241	$2.241	$2.241	$0.000	$0.000	$0.000	$2.241	$2.241	$2.241
5										
6	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	3 ESM	$0.001	$0.001	$0.001	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001
8	5 RSAM	$0.143	$0.143	$0.143	$0.000	$0.000	$0.000	$0.143	$0.143	$0.143
9	Subtotal Delivery Margin Related Charges per GJ	$2.385	$2.385	$2.385	$0.000	$0.000	$0.000	$2.385	$2.385	$2.385
10										
11	Commodity Related Charges									
12	Commodity Gas Cost Recovery Charge per GJ	$7.038	$7.038	$7.038	$0.644	$0.644	$0.644	$7.681	$7.681	$7.681
13	Midstream Gas Cost Recovery Charge per GJ	$0.704	$0.593	$0.731				$0.704	$0.593	$0.731
14	Riders: 1 Propane Surcharge (Revelstoke only)		$4.067			$0.000			$4.067	
15	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16	8 Unbundling Recovery	$0.056	$0.056	$0.056	$0.000	$0.000	$0.000	$0.056	$0.056	$0.056
17	Subtotal Commodity Related Charges per GJ	$7.798	$7.687	$7.825	$0.644	$0.644	$0.644	$8.441	$8.330	$8.468
18										
19										
20	Total Variable Cost per GJ	$10.183	$10.072	$10.210	$0.644	$0.644	$0.644	$10.826	$10.715	$10.853
21										
22	Revelstoke Variable Cost per GJ									
23	(Includes Rider 1, Excludes Rider 8)		$14.083			$0.644			$14.726	
24										
25										
26										

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Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE	Existing 2005 Rates			2005 Gas Cost Changes			July 1, 2005 Approved Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$119.83	$119.83	$119.83	$0.00	$0.00	$0.00	$119.83	$119.83	$119.83
3										
4	Delivery Charge per gigajoule	$1.932	$1.932	$1.932	$0.000	$0.000	$0.000	$1.932	$1.932	$1.932
5										
6	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	3 ESM	$0.001	$0.001	$0.001	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001
8	5 RSAM	$0.143	$0.143	$0.143	$0.000	$0.000	$0.000	$0.143	$0.143	$0.143
9	Subtotal Delivery Margin Related Charges per GJ	$2.076	$2.076	$2.076	$0.000	$0.000	$0.000	$2.076	$2.076	$2.076
10										
11	Commodity Related Charges									
12	Commodity Cost Recovery	$6.938	$6.938	$6.938	$0.644	$0.644	$0.644	$7.582	$7.582	$7.582
13	Midstream Cost Recovery	$0.537	$0.440	$0.572				$0.537	$0.440	$0.572
14	Riders: 1 Propane Surcharge (Revelstoke only)		$4.320			$0.000			$4.320	
15	6 MCRA		$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16	8 Unbundling Recovery	$0.056	$0.056	$0.056	$0.000	$0.000	$0.000	$0.056	$0.056	$0.056
17	Subtotal Commodity Related Charges per GJ	$7.531	$7.434	$7.566	$0.644	$0.644	$0.644	$8.175	$8.078	$8.210
18										
19	Total Variable Cost per GJ	$9.607	$9.510	$9.642	$0.644	$0.644	$0.644	$10.251	$10.154	$10.286
20										
21										
22										
23	Revelstoke Variable Cost per GJ									
24	(Includes Rider 1, Excludes Rider 8)		$13.774			$0.644			$14.418	
25										
26										
27										

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
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Line No.	RATE SCHEDULE 4: SEASONAL SERVICE	Existing 2005 Rates			2005 Gas Cost Changes			July 1, 2005 Approved Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Basic Charge per Month	$397.00	$397.00	$397.00	$0.00	$0.00	$0.00	$397.00	$397.00	$397.00
2										
3	Delivery Charge per gigajoule									
4	(a) Off-Peak Period	$0.690	$0.690	$0.690	$0.000	$0.000	$0.000	$0.690	$0.690	$0.690
5	(b) Extension Period	$1.392	$1.392	$1.392	$0.000	$0.000	$0.000	$1.392	$1.392	$1.392
6										
7	Gas Cost Recovery Charge per GJ									
8	(a) Off-Peak Period									
9	Commodity Cost Recovery	$6.847	$6.847	$6.847	$0.622	$0.622	$0.622	$7.469	$7.469	$7.469
10	Midstream Cost Recovery	$0.382	$0.298	$0.425	$0.000	$0.000	$0.000	$0.382	$0.298	$0.425
11		$7.229	$7.145	$7.272	$0.622	$0.622	$0.622	$7.851	$7.767	$7.894
12	(b) Extension Period									
13	Commodity Cost Recovery	$6.847	$6.847	$6.847	$0.622	$0.622	$0.622	$7.469	$7.469	$7.469
14	Midstream Cost Recovery	$0.382	$0.298	$0.425	$0.000	$0.000	$0.000	$0.382	$0.298	$0.425
15		$7.229	$7.145	$7.272	$0.622	$0.622	$0.622	$7.851	$7.767	$7.894
16	Unauthorized Gas Charge	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17	per GJ during peak period									
18										
19										
20	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
21	3 ESM	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
22	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
23										
24	Total Variable Cost per GJ between									
25	(a) Off-Peak Period	$7.919	$7.835	$7.962	$0.622	$0.622	$0.622	$8.541	$8.457	$8.584
26	(b) Extension Period	$8.621	$8.537	$8.664	$0.622	$0.622	$0.622	$9.243	$9.159	$9.286

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
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Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE	Existing 2005 Rates			2005 Gas Cost Changes			July 1, 2005 Approved Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Basic Charge per Month	$530.00	$530.00	$530.00	$0.00	$0.00	$0.00	$530.00	$530.00	$530.00
2										
3										
4	Demand Charge per GJ	$13.250	$13.250	$13.250	$0.000	$0.000	$0.000	$13.250	$13.250	$13.250
5										
6										
7	Delivery Charge per gigajoule	$0.536	$0.536	$0.536	$0.000	$0.000	$0.000	$0.536	$0.536	$0.536
8										
9	Commodity Related Charges									
10	Commodity Cost Recovery	$6.847	$6.847	$6.847	$0.622	$0.622	$0.622	$7.469	$7.469	$7.469
11	Midstream Cost Recovery	$0.382	$0.298	$0.425	$0.000	$0.000	$0.000	$0.382	$0.298	$0.425
12		7.229	7.145	7.272	0.622	0.622	0.622	7.851	7.767	7.894
13	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	3 ESM	$0.001	$0.001	$0.001	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001
15	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16										
17	Total Variable Cost per GJ	$7.766	$7.682	$7.809	$0.622	$0.622	$0.622	$8.388	$8.304	$8.431

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
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Line No.	RATE SCHEDULE 6: NGV - STATIONS	Existing 2005 Rates			2005 Gas Cost Changes			July 1, 2005 Approved Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
					$0.00					
1	Basic Charge per Month	$55.80	$55.80	$55.80	$0.00	$0.00	$0.00	$55.80	$55.80	$55.80
2					0.0000%					
3										
4	Delivery Charge per gigajoule	$3.072	$3.072	$3.072	$0.000	$0.000	$0.000	$3.072	$3.072	$3.072
5										
6	Commodity Related Charges									
7	Commodity Cost Recovery	$6.736	$6.736	$6.736	$0.584	$0.584	$0.584	$7.319	$7.319	$7.319
8	Midstream Cost Recovery	$0.199	$0.134	$0.134	$0.000	$0.000	$0.000	$0.199	$0.134	$0.134
9		6.935	6.870	6.870	0.584	0.584	0.584	7.518	7.453	7.453
10	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
11	3 ESM	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
12	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
13										
14										
15	Total Variable Cost per GJ	$10.007	$9.942	$9.942	$0.584	$0.584	$0.584	$10.590	$10.525	$10.525

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
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RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	Existing Rates	2005 Gas Cost Changes Changes	July 1, 2005 Permanent Rates
	(1)	(2)	-3	-4
1	Lower Mainland Service Area			
2	Basic Charge per Month	$78.60	$0.00	$78.60
3	Minimum Charges	$125.00	$0.00	$125.00
4				
5	Delivery Charge per gigajoule	$3.072	$0.000	$3.072
6	Commodity Related Charges			
7	Commodity Cost Recovery	$6.736	$0.584	$7.319
8	Midstream Cost Recovery	$0.199	$0.000	$0.199
9		$6.935	$0.584	$7.518
10	Compression Charge per GJ	$5.280	$0.000	$5.280
11				
12	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000
13	3 ESM	$0.000	$0.000	$0.000
14	6 MCRA	$0.000	$0.000	$0.000
15				
16				
17	Total Variable Cost per GJ	$15.287	$0.584	$15.870

Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES	Existing 2005 Rates			2005 Gas Cost Changes			July 1, 2005 Approved Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
					$3.74					
1	Basic Charge per Month	$795.00	$795.00	$795.00	$0.00	$0.00	$0.00	$795.00	$795.00	$795.00
2					0.0000%					
3	Delivery Charge per gigajoule	$0.895	$0.895	$0.895	$0.000	$0.000	$0.000	$0.895	$0.895	$0.895
4										
5	Commodity Related Charges per GJ									
6										
7	Commodity Cost Recovery	$6.847	$6.847	$6.847	$0.622	$0.622	$0.622	$7.469	$7.469	$7.469
8	Midstream Cost Recovery	$0.382	$0.298	$0.425	$0.000	$0.000	$0.000	$0.382	$0.298	$0.425
9		$7.229	$7.145	$7.272	$0.622	$0.622	$0.622	$7.851	$7.767	$7.894
10										
11										
12										
13										
14										
15	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
16										
17										
18										
19	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
20	3 ESM	$0.001	$0.001	$0.001	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001
21	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
22										
23										
24										
25	Total Variable Cost per GJ	$8.125	$8.041	$8.168	$0.622	$0.622	$0.622	$8.747	$8.663	$8.790

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
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	RATE SCHEDULE 1: RESIDENTIAL SERVICE	**Existing 2005 Rates**			**2005 Gas Cost Changes**			**October 1, 2005 Approved Rates**		
Line No.	Particulars	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	-1	(2)	-3	-4	-5	-6	-7	-8	-9	-10
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$10.70	$10.70	$10.70	$0.00	$0.00	$0.00	$10.70	$10.70	$10.70
3										
4	Delivery Charge per gigajoule	$2.677	$2.677	$2.677	$0.000	$0.000	$0.000	$2.677	$2.677	$2.677
5										
6	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	3 ESM	$0.002	$0.002	$0.002	$0.000	$0.000	$0.000	$0.002	$0.002	$0.002
8	5 RSAM	$0.143	$0.143	$0.143	$0.000	$0.000	$0.000	$0.143	$0.143	$0.143
9	Subtotal Delivery Margin Related Charges per GJ	$2.822	$2.822	$2.822	$0.000	$0.000	$0.000	$2.822	$2.822	$2.822
10										
11	Commodity Related Charges									
12	Commodity Gas Cost Recovery Charge per GJ	$7.658	$7.658	$7.658	$1.634	$1.634	$1.634	$9.292	$9.292	$9.292
13	Midstream Gas Cost Recovery Charge per GJ	0.649	0.542	0.678	$0.000	$0.000	$0.000	0.649	0.542	0.678
14	Riders: 1 Propane Surcharge (Revelstoke only)		$4.589			$0.648			$5.237	
15	6 MCRA				$0.000	$0.000	$0.000			
16	9 Stable Rate Recovery	0.006	0.006	0.006	$0.000	$0.000	$0.000	0.006	0.006	0.006
17	Subtotal Commodity Related Charges per GJ	$8.313	$8.206	$8.342	$1.634	$1.634	$1.634	$9.947	$9.840	$9.976
18										
19	Total Variable Cost per GJ	$11.135	$11.028	$11.164	$1.634	$1.634	$1.634	$12.769	$12.662	$12.798
20										
21	Revelstoke Variable Cost per GJ									
22	(Includes Rider 1, Excludes Rider 9)		$15.611			$2.282			$17.893	
23										
24										
25										

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Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE	Existing 2005 Rates			2005 Gas Cost Changes			October 1, 2005 Approved Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$22.46	$22.46	$22.46	$0.00	$0.00	$0.00	$22.46	$22.46	$22.46
3										
4	Delivery Charge per gigajoule	$2.241	$2.241	$2.241	$0.000	$0.000	$0.000	$2.241	$2.241	$2.241
5										
6	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	3 ESM	$0.001	$0.001	$0.001	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001
8	5 RSAM	$0.143	$0.143	$0.143	$0.000	$0.000	$0.000	$0.143	$0.143	$0.143
9	Subtotal Delivery Margin Related Charges per GJ	$2.385	$2.385	$2.385	$0.000	$0.000	$0.000	$2.385	$2.385	$2.385
10										
11	Commodity Related Charges									
12	Commodity Gas Cost Recovery Charge per GJ	$7.681	$7.681	$7.681	$1.636	$1.636	$1.636	$9.317	$9.317	$9.317
13	Midstream Gas Cost Recovery Charge per GJ	$0.704	$0.593	$0.731	$0.000	$0.000	$0.000	$0.704	$0.593	$0.731
14	Riders: 1 Propane Surcharge (Revelstoke only)		$3.424			$0.646			$4.070	
15	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16	8 Unbundling Recovery	$0.056	$0.056	$0.056	$0.000	$0.000	$0.000	$0.056	$0.056	$0.056
17	Subtotal Commodity Related Charges per GJ	$8.441	$8.330	$8.468	$1.636	$1.636	$1.636	$10.077	$9.966	$10.104
18										
19										
20	Total Variable Cost per GJ	$10.826	$10.715	$10.853	$1.636	$1.636	$1.636	$12.462	$12.351	$12.489
21										
22	Revelstoke Variable Cost per GJ									
23	(Includes Rider 1, Excludes Rider 8)		$14.083			$2.282			$16.365	
24										
25										
26										

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	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE	**Existing 2005 Rates**			**2005 Gas Cost Changes**			**October 1, 2005 Approved Rates**		
Line No.	Particulars	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$119.83	$119.83	$119.83	$0.00	$0.00	$0.00	$119.83	$119.83	$119.83
3										
4	Delivery Charge per gigajoule	$1.932	$1.932	$1.932	$0.000	$0.000	$0.000	$1.932	$1.932	$1.932
5										
6	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	3 ESM	$0.001	$0.001	$0.001	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001
8	5 RSAM	$0.143	$0.143	$0.143	$0.000	$0.000	$0.000	$0.143	$0.143	$0.143
9	Subtotal Delivery Margin Related Charges per GJ	$2.076	$2.076	$2.076	$0.000	$0.000	$0.000	$2.076	$2.076	$2.076
10										
11	Commodity Related Charges									
12	Commodity Cost Recovery	$7.582	$7.582	$7.582	$1.631	$1.631	$1.631	$9.213	$9.213	$9.213
13	Midstream Cost Recovery	$0.537	$0.440	$0.572	$0.000	$0.000	$0.000	$0.537	$0.440	$0.572
14	Riders: 1 Propane Surcharge (Revelstoke only)		$3.676			$0.651			$4.327	
15	6 MCRA		$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16	8 Unbundling Recovery	$0.056	$0.056	$0.056	$0.000	$0.000	$0.000	$0.056	$0.056	$0.056
17	Subtotal Commodity Related Charges per GJ	$8.175	$8.078	$8.210	$1.631	$1.631	$1.631	$9.806	$9.709	$9.841
18										
19	Total Variable Cost per GJ	$10.251	$10.154	$10.286	$1.631	$1.631	$1.631	$11.882	$11.785	$11.917
20										
21										
22										
23	Revelstoke Variable Cost per GJ									
24	(Includes Rider 1, Excludes Rider 8)		$13.774			$2.282			$16.056	
25										
26										
27										

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Line No.	RATE SCHEDULE 4: SEASONAL SERVICE Particulars	Existing 2005 Rates Lower Mainland	 Inland	 Columbia	2005 Gas Cost Changes Lower Mainland	 Inland	 Columbia	October 1, 2005 Approved Rates Lower Mainland	 Inland	 Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Basic Charge per Month	$397.00	$397.00	$397.00	$0.00	$0.00	$0.00	$397.00	$397.00	$397.00
2										
3	Delivery Charge per gigajoule									
4	(a) Off-Peak Period	$0.690	$0.690	$0.690	$0.000	$0.000	$0.000	$0.690	$0.690	$0.690
5	(b) Extension Period	$1.392	$1.392	$1.392	$0.000	$0.000	$0.000	$1.392	$1.392	$1.392
6										
7	Gas Cost Recovery Charge per GJ									
8	(a) Off-Peak Period									
9	Commodity Cost Recovery	$7.469	$7.469	$7.469	$1.625	$1.625	$1.625	$9.094	$9.094	$9.094
10	Midstream Cost Recovery	$0.382	$0.298	$0.425	$0.000	$0.000	$0.000	$0.382	$0.298	$0.425
11	Subtotal Off -Peak Commodity Related Charges per GJ	$7.851	$7.767	$7.894	$1.625	$1.625	$1.625	$9.476	$9.392	$9.519
12	(b) Extension Period									
13	Commodity Cost Recovery	$7.469	$7.469	$7.469	$1.625	$1.625	$1.625	$9.094	$9.094	$9.094
14	Midstream Cost Recovery	$0.382	$0.298	$0.425	$0.000	$0.000	$0.000	$0.382	$0.298	$0.425
15	Subtotal Extension Commodity Related Charges per GJ	$7.851	$7.767	$7.894	$1.625	$1.625	$1.625	$9.476	$9.392	$9.519
16	Unauthorized Gas Charge	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17	per GJ during peak period									
18										
19										
20	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
21	3 ESM	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
22	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
23										
24	Total Variable Cost per GJ between									
25	(a) Off-Peak Period	$8.541	$8.457	$8.584	$1.625	$1.625	$1.625	$10.166	$10.082	$10.209
26	(b) Extension Period	$9.243	$9.159	$9.286	$1.625	$1.625	$1.625	$10.868	$10.784	$10.911

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Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE Particulars	Existing 2005 Rates Lower Mainland	Existing 2005 Rates Inland	Existing 2005 Rates Columbia	2005 Gas Cost Changes Lower Mainland	2005 Gas Cost Changes Inland	2005 Gas Cost Changes Columbia	October 1, 2005 Approved Rates Lower Mainland	October 1, 2005 Approved Rates Inland	October 1, 2005 Approved Rates Columbia
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10
1	Basic Charge per Month	$530.00	$530.00	$530.00	$0.00	$0.00	$0.00	$530.00	$530.00	$530.00
2										
3										
4	Demand Charge per GJ	$13.250	$13.250	$13.250	$0.000	$0.000	$0.000	$13.250	$13.250	$13.250
5										
6										
7	Delivery Charge per gigajoule	$0.536	$0.536	$0.536	$0.000	$0.000	$0.000	$0.536	$0.536	$0.536
8										
9	Commodity Related Charges									
10	Commodity Cost Recovery	$7.469	$7.469	$7.469	$1.625	$1.625	$1.625	$9.094	$9.094	$9.094
11	Midstream Cost Recovery	$0.382	$0.298	$0.425	$0.000	$0.000	$0.000	$0.382	$0.298	$0.425
12	Subtotal Commodity Related Charges per GJ	7.851	7.767	7.894	1.625	1.625	1.625	9.476	9.392	9.519
13	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	3 ESM	$0.001	$0.001	$0.001	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001
15	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16										
17	Total Variable Cost per GJ	$8.388	$8.304	$8.431	$1.625	$1.625	$1.625	$10.013	$9.929	$10.056

TERASEN GAS INC.
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Line No.	**RATE SCHEDULE 6: NGV - STATIONS** Particulars	**Existing 2005 Rates** Lower Mainland	Inland	Columbia	**2005 Gas Cost Changes** Lower Mainland	Inland	Columbia	**October 1, 2005 Approved Rates** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$55.80	$55.80	$55.80	$0.00	$0.00	$0.00	$55.80	$55.80	$55.80
2										
3										
4	Delivery Charge per gigajoule	$3.072	$3.072	$3.072	$0.000	$0.000	$0.000	$3.072	$3.072	$3.072
5										
6	Commodity Related Charges									
7	Commodity Cost Recovery	$7.319	$7.319	$7.319	$1.617	$1.617	$1.617	$8.936	$8.936	$8.936
8	Midstream Cost Recovery	$0.199	$0.134	$0.134	$0.000	$0.000	$0.000	$0.199	$0.134	$0.134
9	Subtotal Commodity Related Charges per GJ	7.518	7.453	7.453	1.617	1.617	1.617	9.135	9.070	9.070
10	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
11	3 ESM	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
12	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
13										
14										
15	Total Variable Cost per GJ	$10.590	$10.525	$10.525	$1.617	$1.617	$1.617	$12.207	$12.142	$12.142

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
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RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	**Existing Rates**	**2005 Gas Cost Changes Changes**	**October 1, 2005 Permanent Rates**
	(1)	(2)	-3	-4
1	Lower Mainland Service Area			
2	Basic Charge per Month	$78.60	$0.00	$78.60
3	Minimum Charges	$125.00	$0.00	$125.00
4				
5	Delivery Charge per gigajoule	$3.072	$0.000	$3.072
6	Commodity Related Charges			
7	Commodity Cost Recovery	$7.319	$1.617	$8.936
8	Midstream Cost Recovery	$0.199	$0.000	$0.199
9	Subtotal Commodity Related Charges per GJ	$7.518	$1.617	$9.135
10	Compression Charge per GJ	$5.280	$0.000	$5.280
11				
12	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000
13	3 ESM	$0.000	$0.000	$0.000
14	6 MCRA	$0.000	$0.000	$0.000
15				
16				
17	Total Variable Cost per GJ	$15.870	$1.617	$17.487

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
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Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES Particulars	Existing 2005 Rates Lower Mainland	 Inland	 Columbia	2005 Gas Cost Changes Lower Mainland	 Inland	 Columbia	October 1, 2005 Approved Rates Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$795.00	$795.00	$795.00	$0.00	$0.00	$0.00	$795.00	$795.00	$795.00
2										
3	Delivery Charge per gigajoule	$0.895	$0.895	$0.895	$0.000	$0.000	$0.000	$0.895	$0.895	$0.895
4										
5	Commodity Related Charges per GJ									
6										
7	Commodity Cost Recovery	$7.469	$7.469	$7.469	$1.625	$1.625	$1.625	$9.094	$9.094	$9.094
8	Midstream Cost Recovery	$0.382	$0.298	$0.425	$0.000	$0.000	$0.000	$0.382	$0.298	$0.425
9	Subtotal Commodity Related Charges per GJ	$7.851	$7.767	$7.894	$1.625	$1.625	$1.625	$9.476	$9.392	$9.519
10										
11										
12										
13										
14										
15	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
16										
17										
18										
19	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
20	3 ESM	$0.001	$0.001	$0.001	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001
21	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
22										
23										
24										
25	Total Variable Cost per GJ	$8.747	$8.663	$8.790	$1.625	$1.625	$1.625	$10.372	$10.288	$10.415

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
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BCUC ORDER NO. G-131-05 / G-132-05 / G-146-05

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE	Existing 2005 Rates			2006 Revenue Requirement, Gas Cost and Rider Changes			January 1, 2006 Interim Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$10.70	$10.70	$10.70	$0.42	$0.42	$0.42	$11.12	$11.12	$11.12
3										
4	Delivery Charge per gigajoule	$2.677	$2.677	$2.677	$0.104	$0.104	$0.104	$2.781	$2.781	$2.781
5										
6	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	3 ESM	$0.002	$0.002	$0.002	($0.065)	($0.065)	($0.065)	($0.063)	($0.063)	($0.063)
8	5 RSAM	$0.143	$0.143	$0.143	$0.023	$0.023	$0.023	$0.166	$0.166	$0.166
9	Subtotal Delivery Margin Related Charges per GJ	$2.822	$2.822	$2.822	$0.062	$0.062	$0.062	$2.884	$2.884	$2.884
10										
11	Commodity Related Charges									
12	Commodity Gas Cost Recovery Charge per GJ	$9.292	$9.292	$9.292	$0.482	$0.482	$0.482	$9.774	$9.774	$9.774
13	Midstream Gas Cost Recovery Charge per GJ	$0.649	$0.542	$0.678	($0.036)	$0.014	($0.036)	$0.613	$0.556	$0.642
14	Riders: 1 Propane Surcharge (Revelstoke only)		$5.237			$0.110			$5.347	
15	6 MCRA				($0.606)	($0.606)	($0.606)	($0.606)	($0.606)	($0.606)
16	9 Stable Rate Recovery	$0.006	$0.006	$0.006	($0.002)	($0.002)	($0.002)	$0.004	$0.004	$0.004
17	Subtotal Commodity Related Charges per GJ	$9.947	$9.840	$9.976	($0.162)	($0.112)	($0.162)	$9.785	$9.728	$9.814
18										
19	Total Variable Cost per GJ	$12.769	$12.662	$12.798	($0.100)	($0.050)	($0.100)	$12.669	$12.612	$12.698
20										
21	Revelstoke Variable Cost per GJ									
22	(Includes Riders 1 & 6, Excludes Rider 9)		$17.893			$0.062			$17.955	

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
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Line No.	**RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE** Particulars	**Existing 2005 Rates** Lower Mainland	Inland	Columbia	**2006 Revenue Requirement, Gas Cost and Rider Changes** Lower Mainland	Inland	Columbia	**January 1, 2006 Interim Rates** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$22.46	$22.46	$22.46	$0.87	$0.87	$0.87	$23.33	$23.33	$23.33
3										
4	Delivery Charge per gigajoule	$2.241	$2.241	$2.241	$0.087	$0.087	$0.087	$2.328	$2.328	$2.328
5										
6	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	3 ESM	$0.001	$0.001	$0.001	($0.050)	($0.050)	($0.050)	($0.049)	($0.049)	($0.049)
8	5 RSAM	$0.143	$0.143	$0.143	$0.023	$0.023	$0.023	$0.166	$0.166	$0.166
9	Subtotal Delivery Margin Related Charges per GJ	$2.385	$2.385	$2.385	$0.060	$0.060	$0.060	$2.445	$2.445	$2.445
10										
11	Commodity Related Charges									
12	Commodity Gas Cost Recovery Charge per GJ	$9.317	$9.317	$9.317	$0.480	$0.480	$0.480	$9.797	$9.797	$9.797
13	Midstream Gas Cost Recovery Charge per GJ	$0.704	$0.593	$0.731	($0.074)	($0.023)	($0.075)	$0.630	$0.570	$0.656
14	Riders: 1 Propane Surcharge (Revelstoke only)		$4.070			$0.178			$4.248	
15	6 MCRA	$0.000	$0.000	$0.000	($0.635)	($0.635)	($0.635)	($0.635)	($0.635)	($0.635)
16	8 Unbundling Recovery	$0.056	$0.056	$0.056	($0.011)	($0.011)	($0.011)	$0.045	$0.045	$0.045
17	Subtotal Commodity Related Charges per GJ	$10.077	$9.966	$10.104	($0.240)	($0.189)	($0.241)	$9.837	$9.777	$9.863
18										
19										
20	Total Variable Cost per GJ	$12.462	$12.351	$12.489	($0.180)	($0.129)	($0.181)	$12.282	$12.222	$12.308
21										
22	Revelstoke Variable Cost per GJ									
23	(Includes Riders 1 & 6, Excludes Rider 8)		$16.365			$0.060			$16.425	

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Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE	Existing 2005 Rates			2006 Revenue Requirement, Gas Cost and Rider Changes			January 1, 2006 Interim Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$119.83	$119.83	$119.83	$4.67	$4.67	$4.67	$124.50	$124.50	$124.50
3										
4	Delivery Charge per gigajoule	$1.932	$1.932	$1.932	$0.075	$0.075	$0.075	$2.007	$2.007	$2.007
5										
6	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	3 ESM	$0.001	$0.001	$0.001	($0.038)	($0.038)	($0.038)	($0.037)	($0.037)	($0.037)
8	5 RSAM	$0.143	$0.143	$0.143	$0.023	$0.023	$0.023	$0.166	$0.166	$0.166
9	Subtotal Delivery Margin Related Charges per GJ	$2.076	$2.076	$2.076	$0.060	$0.060	$0.060	$2.136	$2.136	$2.136
10										
11	Commodity Related Charges									
12	Commodity Cost Recovery	$9.213	$9.213	$9.213	$0.486	$0.486	$0.486	$9.699	$9.699	$9.699
13	Midstream Cost Recovery	$0.537	$0.440	$0.572	$0.022	$0.070	$0.024	$0.559	$0.510	$0.596
14	Riders: 1 Propane Surcharge (Revelstoke only)		$4.327			($0.043)			$4.284	
15	6 MCRA		$0.000	$0.000	($0.513)	($0.513)	($0.513)	($0.513)	($0.513)	($0.513)
16	8 Unbundling Recovery	$0.056	$0.056	$0.056	($0.011)	($0.011)	($0.011)	$0.045	$0.045	$0.045
17	Subtotal Commodity Related Charges per GJ	$9.806	$9.709	$9.841	($0.016)	$0.032	($0.014)	$9.790	$9.741	$9.827
18										
19	Total Variable Cost per GJ	$11.882	$11.785	$11.917	$0.044	$0.092	$0.046	$11.926	$11.877	$11.963
20										
21										
22										
23	Revelstoke Variable Cost per GJ									
24	(Includes Riders 1 & 6, Excludes Rider 8)		$16.056			$0.060			$16.116	

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Line No.	RATE SCHEDULE 4: SEASONAL SERVICE	Existing 2005 Rates			2006 Revenue Requirement, Gas Cost and Rider Changes			January 1, 2006 Interim Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$397.00	$397.00	$397.00	$15.00	$15.00	$15.00	$412.00	$412.00	$412.00
2										
3	Delivery Charge per gigajoule									
4	(a) Off-Peak Period	$0.690	$0.690	$0.690	$0.027	$0.027	$0.027	$0.717	$0.717	$0.717
5	(b) Extension Period	$1.392	$1.392	$1.392	$0.054	$0.054	$0.054	$1.446	$1.446	$1.446
6										
7	Gas Cost Recovery Charge per GJ									
8	(a) Off-Peak Period									
9	Commodity Cost Recovery	$9.094	$9.094	$9.094	$0.493	$0.493	$0.493	$9.587	$9.587	$9.587
10	Midstream Cost Recovery	$0.382	$0.298	$0.425	$0.095	$0.144	$0.102	$0.477	$0.442	$0.527
11	Subtotal Off -Peak Commodity Related Charges per GJ	$9.476	$9.392	$9.519	$0.588	$0.637	$0.595	$10.064	$10.029	$10.114
12	(b) Extension Period									
13	Commodity Cost Recovery	$9.094	$9.094	$9.094	$0.493	$0.493	$0.493	$9.587	$9.587	$9.587
14	Midstream Cost Recovery	$0.382	$0.298	$0.425	$0.095	$0.144	$0.102	$0.477	$0.442	$0.527
15	Subtotal Extension Commodity Related Charges per GJ	$9.476	$9.392	$9.519	$0.588	$0.637	$0.595	$10.064	$10.029	$10.114
16	Unauthorized Gas Charge	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17	per GJ during peak period									
18										
19										
20	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
21	3 ESM	$0.000	$0.000	$0.000	($0.025)	($0.025)	($0.025)	($0.025)	($0.025)	($0.025)
22	6 MCRA	$0.000	$0.000	$0.000	($0.372)	($0.372)	($0.372)	($0.372)	($0.372)	($0.372)
23										
24	Total Variable Cost per GJ between									
25	(a) Off-Peak Period	$10.166	$10.082	$10.209	$0.218	$0.267	$0.225	$10.384	$10.349	$10.434
26	(b) Extension Period	$10.868	$10.784	$10.911	$0.245	$0.294	$0.252	$11.113	$11.078	$11.163

Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE Particulars	Existing 2005 Rates Lower Mainland	Existing 2005 Rates Inland	Existing 2005 Rates Columbia	2006 Revenue Requirement, Gas Cost and Rider Changes Lower Mainland	2006 Revenue Requirement, Gas Cost and Rider Changes Inland	2006 Revenue Requirement, Gas Cost and Rider Changes Columbia	January 1, 2006 Interim Rates Lower Mainland	January 1, 2006 Interim Rates Inland	January 1, 2006 Interim Rates Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$530.00	$530.00	$530.00	$21.00	$21.00	$21.00	$551.00	$551.00	$551.00
2										
3										
4	Demand Charge per GJ	$13.250	$13.250	$13.250	$0.516	$0.516	$0.516	$13.766	$13.766	$13.766
5										
6										
7	Delivery Charge per gigajoule	$0.536	$0.536	$0.536	$0.021	$0.021	$0.021	$0.557	$0.557	$0.557
8										
9	Commodity Related Charges									
10	Commodity Cost Recovery	$9.094	$9.094	$9.094	$0.493	$0.493	$0.493	$9.587	$9.587	$9.587
11	Midstream Cost Recovery	$0.382	$0.298	$0.425	$0.095	$0.144	$0.102	$0.477	$0.442	$0.527
12	Subtotal Commodity Related Charges per GJ	$9.476	$9.392	$9.519	$0.588	$0.637	$0.595	$10.064	$10.029	$10.114
13	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	3 ESM	$0.001	$0.001	$0.001	($0.028)	($0.028)	($0.028)	($0.027)	($0.027)	($0.027)
15	6 MCRA	$0.000	$0.000	$0.000	($0.372)	($0.372)	($0.372)	($0.372)	($0.372)	($0.372)
16										
17	Total Variable Cost per GJ	$10.013	$9.929	$10.056	$0.209	$0.258	$0.216	$10.222	$10.187	$10.272

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Line No.	RATE SCHEDULE 6: NGV - STATIONS	Existing 2005 Rates			2006 Revenue Requirement, Gas Cost and Rider Changes			January 1, 2006 Interim Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$55.80	$55.80	$55.80	$2.00	$2.00	$2.00	$58.00	$58.00	$58.00
2										
3										
4	Delivery Charge per gigajoule	$3.072	$3.072	$3.072	$0.120	$0.120	$0.120	$3.192	$3.192	$3.192
5										
6	Commodity Related Charges									
7	Commodity Cost Recovery	$8.936	$8.936	$8.936	$0.502	$0.502	$0.502	$9.438	$9.438	$9.438
8	Midstream Cost Recovery	$0.199	$0.134	$0.134	$0.170	$0.218	$0.218	$0.369	$0.352	$0.352
9	Subtotal Commodity Related Charges per GJ	$9.135	$9.070	$9.070	$0.672	$0.720	$0.720	$9.807	$9.790	$9.790
10	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
11	3 ESM	$0.000	$0.000	$0.000	($0.051)	($0.051)	($0.051)	($0.051)	($0.051)	($0.051)
12	6 MCRA	$0.000	$0.000	$0.000	($0.184)	($0.184)	($0.184)	($0.184)	($0.184)	($0.184)
13										
14										
15	Total Variable Cost per GJ	$12.207	$12.142	$12.142	$0.557	$0.605	$0.605	$12.764	$12.747	$12.747

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RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	Existing Rates	2006 Revenue Requirement, Gas Cost and Rider Changes	January 1, 2006 Interim Rates
	(1)	(2)	(3)	(4)
1	Lower Mainland Service Area			
2	Basic Charge per Month	$78.60	$3.10	$81.70
3	Minimum Charges	$125.00	$0.00	$125.00
4				
5	Delivery Charge per gigajoule	$3.072	$0.120	$3.192
6	Commodity Related Charges			
7	Commodity Cost Recovery	$8.936	$0.502	$9.438
8	Midstream Cost Recovery	$0.199	$0.170	$0.369
9	Subtotal Commodity Related Charges per GJ	$9.135	$0.672	$9.807
10	Compression Charge per GJ	$5.280	$0.000	$5.280
11				
12	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000
13	3 ESM	$0.000	($0.051)	($0.051)
14	6 MCRA	$0.000	($0.184)	($0.184)
15				
16				
17	Total Variable Cost per GJ	$17.487	$0.557	$18.044

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Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES Particulars	Existing 2005 Rates Lower Mainland	 Inland	 Columbia	2006 Revenue Requirement, Gas Cost and Rider Changes Lower Mainland	 Inland	 Columbia	January 1, 2006 Interim Rates Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$795.00	$795.00	$795.00	$31.00	$31.00	$31.00	$826.00	$826.00	$826.00
2										
3	Delivery Charge per gigajoule	$0.895	$0.895	$0.895	$0.035	$0.035	$0.035	$0.930	$0.930	$0.930
4										
5	Commodity Related Charges per GJ									
6										
7	Commodity Cost Recovery	$9.094	$9.094	$9.094	$0.493	$0.493	$0.493	$9.587	$9.587	$9.587
8	Midstream Cost Recovery	$0.382	$0.298	$0.425	$0.095	$0.144	$0.102	$0.477	$0.442	$0.527
9	Subtotal Commodity Related Charges per GJ	$9.476	$9.392	$9.519	$0.588	$0.637	$0.595	$10.064	$10.029	$10.114
10										
11										
12										
13										
14										
15	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
16										
17										
18										
19	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
20	3 ESM	$0.001	$0.001	$0.001	($0.017)	($0.017)	($0.017)	($0.016)	($0.016)	($0.016)
21	6 MCRA	$0.000	$0.000	$0.000	($0.372)	($0.372)	($0.372)	($0.372)	($0.372)	($0.372)
22										
23										
24										
25	Total Variable Cost per GJ	$10.372	$10.288	$10.415	$0.234	$0.283	$0.241	$10.606	$10.571	$10.656

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Line No.	RATE SCHEDULE 22: LARGE INDUSTRIAL T-SERVICE Particulars	Existing 2005 Rates Lower Mainland	Inland	Columbia	2006 Revenue Requirement and Rider Changes Lower Mainland	Inland	Columbia	January 1, 2006 Interim Rates Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$3,313.00	$3,313.00	$3,313.00	$129.00	$129.00	$129.00	$3,442.00	$3,442.00	$3,442.00
2										
3	Delivery Charge (Interr. MTQ)	$0.663	$0.663	$0.663	$0.026	$0.026	$0.026	$0.689	$0.689	$0.689
4										
5										
6	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
7										
8										
9	Demand Surcharge per GJ	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00	$17.00	$17.00	$17.00
10										
11	Balancing Service per GJ									
12	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.30	n/a	$0.000	$0.000	$0.000	$0.30	$0.30	n/a
13	(b) between and including Nov. 1 and Mar. 31	$1.10	$1.10	n/a	$0.000	$0.000	$0.000	$1.10	$1.10	n/a
14										
15										
16	Charges per GJ for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17										
18										
19	Administration Charge	$70.00	$70.00	$70.00	$3.00	$3.00	$3.00	$73.00	$73.00	$73.00
20										
21	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
22	3 ESM	$0.000	$0.000	$0.000	($0.012)	($0.012)	($0.012)	($0.012)	($0.012)	($0.012)
23										
24										
25										
26										
27	Total Variable Cost per GJ	$0.663	$0.663	$0.663	$0.014	$0.014	$0.014	$0.677	$0.677	$0.677

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RATE SCHEDULE 22A:
LARGE INDUSTRIAL T-SERVICE

Line No.	Particulars	Existing Rates	2006 Revenue Requirement and Rider Changes	January 1, 2006 Interim Rates
	(1)	(2)	(3)	(4)
1	Basic Charge per Month	$4,350.00	$169.00	$4,519.00
2				
3	Delivery Charge per GJ - Firm			
4	(a) Firm DTQ	$10.639	$0.414	$11.053
5	(b) Firm MTQ	$0.075	$0.003	$0.078
6				
7	Delivery Charge per GJ - Interr MTQ	$0.850	$0.033	$0.883
8				
9	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
10				
11				
12	Demand Surchage per GJ	$17.00	$0.00	$17.00
13				
14	Balancing Service per GJ			
15	(a) between and including Apr. 1 and Oct. 31	$0.300	$0.00	$0.300
16	(b) between and including Nov. 1 and Mar. 31	$1.100	$0.00	$1.100
17				
18	Charges per GJ for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
19				
20				
21	Replacement Gas	Sumas Daily Price		Sumas Daily Price
22		plus 20 Percent		plus 20 Percent
23				
24	Administration Charge	$70.00	$3.00	$73.00
25				
26	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000
27	3 ESM	$0.000	($0.010)	($0.010)
28				
29	Total Variable Cost per GJ			
30	(a) Firm MTQ	$0.075	($0.007)	$0.068
31				
32	(b) Interruptible MTQ	$0.850	$0.023	$0.873

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Line No.	RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE	Existing 2005 Rates and Rider (		2006 Revenue Requirement and Rider Changes		January 1, 2006 Interim Rates	
	Particulars	Columbia Except Elkview	Elkview Coal	Columbia Except Elkview	Elkview Coal	Columbia Except Elkview	Elkview Coal
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Basic Charge per Month	$4,103.00	$4,103.00	$160.00	$160.00	$4,263.00	$4,263.00
2							
3	Delivery Charge per GJ - Firm						
4	(a) Firm DTQ	$6.779	$1.539	$0.264	$0.060	$7.043	$1.599
5	(b) Firm MTQ	$0.073	$0.073	$0.003	$0.003	$0.076	$0.076
6							
7	Delivery Charge per GJ - Interr MTQ						
8	(a) between and including Apr. 1 and Oct. 31	$0.675	$0.168	$0.026	$0.007	$0.701	$0.175
9	(b) between and including Nov. 1 and Mar. 31	$0.973	$0.242	$0.038	$0.009	$1.011	$0.251
10							
11	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
12							
13							
14	Demand Surcharge per GJ	$17.00	$17.00	$0.00	$0.00	$17.00	$17.00
15							
16	Charges per GJ for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
17							
18							
19							
20	Administration Charge	$70.00	$70.00	$3.00	$3.00	$73.00	$73.00
21							
22	Riders: Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
23	ESM	$0.000	$0.000	($0.008)	($0.004)	($0.008)	($0.004)
24							
25							
26							
27							
28							
29							
30	Total Variable Cost per GJ						
31	(a) Firm MTQ	$0.073	$0.073	($0.005)	($0.001)	$0.068	$0.072
32	(b) Interruptible MTQ - Summer	$0.675	$0.168	$0.018	$0.003	$0.693	$0.171
33	- Winter	$0.973	$0.242	$0.030	$0.005	$1.003	$0.247
34							

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Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE Particulars	Existing 2005 Rates Lower Mainland	Existing 2005 Rates Inland	Existing 2005 Rates Columbia	2006 Revenue Requirement and Rider Changes Lower Mainland	2006 Revenue Requirement and Rider Changes Inland	2006 Revenue Requirement and Rider Changes Columbia	January 1, 2006 Interim Rates Lower Mainland	January 1, 2006 Interim Rates Inland	January 1, 2006 Interim Rates Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$119.83	$119.83	$119.83	$4.67	$4.67	$4.67	$124.50	$124.50	$124.50
2										
3										
4	Delivery Charge per GJ	$1.932	$1.932	$1.932	$0.075	$0.075	$0.075	$2.007	$2.007	$2.007
5										
6	Administration Charge	$70.00	$70.00	$70.00	$3.00	$3.00	$3.00	$73.00	$73.00	$73.00
7										
8	Sales									
9	(a) Charge per GJ for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per GJ for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per GJ for UOR Gas									
13										
14	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	3 ESM	$0.001	$0.001	$0.001	($0.038)	($0.038)	($0.038)	($0.037)	($0.037)	($0.037)
16	5 RSAM	$0.143	$0.143	$0.143	$0.023	$0.023	$0.023	$0.166	$0.166	$0.166
17										
18										
19										
20	Total Variable Cost per GJ	$2.076	$2.076	$2.076	$0.060	$0.060	$0.060	$2.136	$2.136	$2.136

Line No.	RATE SCHEDULE 25 GENERAL FIRM T-SERVICE Particulars	Existing 2005 Rates Lower Mainland	Inland	Columbia	2006 Revenue Requirement and Rider Changes Lower Mainland	Inland	Columbia	January 1, 2006 Interim Rates Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$530.00	$530.00	$530.00	$21.00	$21.00	$21.00	$551.00	$551.00	$551.00
2										
3	Demand Charge per GJ	$13.250	$13.250	$13.250	$0.516	$0.516	$0.516	$13.766	$13.766	$13.766
4										
5										
6	Delivery Charge (Interr. MTQ)	$0.536	$0.536	$0.536	$0.021	$0.021	$0.021	$0.557	$0.557	$0.557
7										
8	Administration Charge	$70.00	$70.00	$70.00	$3.00	$3.00	$3.00	$73.00	$73.00	$73.00
9										
10	Sales									
11	(a) Charge per GJ for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per GJ for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per GJ for UOR Gas									
15										
16										
17										
18	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
19	3 ESM	$0.001	$0.001	$0.001	($0.028)	($0.028)	($0.028)	($0.027)	($0.027)	($0.027)
20										
21										
22	Total Variable Cost per GJ	$0.537	$0.537	$0.537	($0.007)	($0.007)	($0.007)	$0.530	$0.530	$0.530

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Line No.	RATE SCHEDULE 27: INTERRUPTIBLE T-SERVICE	Existing 2005 Rates			2006 Revenue Requirement and Rider Changes			January 1, 2006 Interim Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$795.00	$795.00	$795.00	$31.00	$31.00	$31.00	$826.00	$826.00	$826.00
2										
3										
4	Delivery Charge (Interr. MTQ)	$0.895	$0.895	$0.895	$0.035	$0.035	$0.035	$0.930	$0.930	$0.930
5										
6	Administration Charge	$70.00	$70.00	$70.00	$3.00	$3.00	$3.00	$73.00	$73.00	$73.00
7										
8	Sales									
9	(a) Charge per GJ for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per GJ for Backstopping Gas									
11	(c) Charge per GJ for UOR Gas									
12										
13	Riders: 2 Reserved for Future Use	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	3 ESM	$0.001	$0.001	$0.001	($0.017)	($0.017)	($0.017)	($0.016)	($0.016)	($0.016)
15										
16										
17	Total Variable Cost per GJ	$0.896	$0.896	$0.896	$0.018	$0.018	$0.018	$0.914	$0.914	$0.914

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Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE Particulars	Existing Jan. 1, 2006 Interim Rates Lower Mainland	Inland	Columbia	2006 Revenue Requirement, Gas Cost and Rider Changes Lower Mainland	Inland	Columbia	April 1, 2006 Proposed Rates Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$11.12	$11.12	$11.12	$0.04	$0.04	$0.04	$11.16	$11.16	$11.16
3										
4	Delivery Charge per gigajoule	$2.781	$2.781	$2.781	$0.010	$0.010	$0.010	$2.791	$2.791	$2.791
5										
6	Riders: 2 Revenue shortfall - 2006Q1	$0.000	$0.000	$0.000	$0.010	$0.010	$0.010	$0.010	$0.010	$0.010
7	3 ESM	($0.063)	($0.063)	($0.063)	$0.000	$0.000	$0.000	($0.063)	($0.063)	($0.063)
8	5 RSAM	$0.166	$0.166	$0.166	$0.000	$0.000	$0.000	$0.166	$0.166	$0.166
9	Subtotal Delivery Margin Related Charges per GJ	$2.884	$2.884	$2.884	$0.020	$0.020	$0.020	$2.904	$2.904	$2.904
10										
11	Commodity Related Charges									
12	Commodity Gas Cost Recovery Charge per GJ	$9.774	$9.774	$9.774	($2.112)	($2.112)	($2.112)	$7.662	$7.662	$7.662
13	Midstream Gas Cost Recovery Charge per GJ	$0.613	$0.556	$0.642	$0.000	$0.000	$0.000	$0.613	$0.556	$0.642
14	Riders: 1 Propane Surcharge (Revelstoke only)		$5.347			$1.648			$6.995	
15	6 MCRA	($0.606)	($0.606)	($0.606)	$0.464	$0.464	$0.464	($0.142)	($0.142)	($0.142)
16	9 Stable Rate Recovery	$0.004	$0.004	$0.004	$0.000	$0.000	$0.000	$0.004	$0.004	$0.004
17	Subtotal Commodity Related Charges per GJ	$9.785	$9.728	$9.814	($1.648)	($1.648)	($1.648)	$8.137	$8.080	$8.166
18										
19	Total Variable Cost per GJ	$12.669	$12.612	$12.698	($1.628)	($1.628)	($1.628)	$11.041	$10.984	$11.070
20										
21	Revelstoke Variable Cost per GJ									
22	(Includes Riders 1 & 6, Excludes Rider 9)		$17.955			$0.020			$17.975	

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Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE Particulars	Existing Jan. 1, 2006 Interim Rates Lower Mainland	 Inland	 Columbia	2006 Revenue Requirement, Gas Cost and Rider Changes Lower Mainland	 Inland	 Columbia	April 1, 2006 Proposed Rates Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$23.33	$23.33	$23.33	$0.09	$0.09	$0.09	$23.42	$23.42	$23.42
3										
4	Delivery Charge per gigajoule	$2.328	$2.328	$2.328	$0.009	$0.009	$0.009	$2.337	$2.337	$2.337
5										
6	Riders: 2 Revenue shortfall - 2006Q1	$0.000	$0.000	$0.000	$0.008	$0.008	$0.008	$0.008	$0.008	$0.008
7	3 ESM	($0.049)	($0.049)	($0.049)	$0.000	$0.000	$0.000	($0.049)	($0.049)	($0.049)
8	5 RSAM	$0.166	$0.166	$0.166	$0.000	$0.000	$0.000	$0.166	$0.166	$0.166
9	Subtotal Delivery Margin Related Charges per GJ	$2.445	$2.445	$2.445	$0.017	$0.017	$0.017	$2.462	$2.462	$2.462
10										
11	Commodity Related Charges									
12	Commodity Gas Cost Recovery Charge per GJ	$9.797	$9.797	$9.797	($2.124)	($2.124)	($2.124)	$7.673	$7.673	$7.673
13	Midstream Gas Cost Recovery Charge per GJ	$0.630	$0.570	$0.656	$0.000	$0.000	$0.000	$0.630	$0.570	$0.656
14	Riders: 1 Propane Surcharge (Revelstoke only)		$4.248			$1.660			$5.908	
15	6 MCRA	($0.635)	($0.635)	($0.635)	$0.464	$0.464	$0.464	($0.171)	($0.171)	($0.171)
16	8 Unbundling Recovery	$0.045	$0.045	$0.045	$0.000	$0.000	$0.000	$0.045	$0.045	$0.045
17	Subtotal Commodity Related Charges per GJ	$9.837	$9.777	$9.863	($1.660)	($1.660)	($1.660)	$8.177	$8.117	$8.203
18										
19										
20	Total Variable Cost per GJ	$12.282	$12.222	$12.308	($1.643)	($1.643)	($1.643)	$10.639	$10.579	$10.665
21										
22	Revelstoke Variable Cost per GJ									
23	(Includes Riders 1 & 6, Excludes Rider 8)		$16.425			$0.017			$16.442	

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Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE	Existing Jan. 1, 2006 Interim Rates			2006 Revenue Requirement, Gas Cost and Rider Changes			April 1, 2006 Proposed Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$124.50	$124.50	$124.50	$0.45	$0.45	$0.45	$124.95	$124.95	$124.95
3										
4	Delivery Charge per gigajoule	$2.007	$2.007	$2.007	$0.007	$0.007	$0.007	$2.014	$2.014	$2.014
5										
6	Riders: 2 Revenue shortfall - 2006Q1	$0.000	$0.000	$0.000	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005
7	3 ESM	($0.037)	($0.037)	($0.037)	$0.000	$0.000	$0.000	($0.037)	($0.037)	($0.037)
8	5 RSAM	$0.166	$0.166	$0.166	$0.000	$0.000	$0.000	$0.166	$0.166	$0.166
9	Subtotal Delivery Margin Related Charges per GJ	$2.136	$2.136	$2.136	$0.012	$0.012	$0.012	$2.148	$2.148	$2.148
10										
11	Commodity Related Charges									
12	Commodity Cost Recovery	$9.699	$9.699	$9.699	($2.072)	($2.072)	($2.072)	$7.627	$7.627	$7.627
13	Midstream Cost Recovery	$0.559	$0.510	$0.596	$0.000	$0.000	$0.000	$0.559	$0.510	$0.596
14	Riders: 1 Propane Surcharge (Revelstoke only)		$4.284			$1.611			$5.895	
15	6 MCRA	($0.513)	($0.513)	($0.513)	$0.461	$0.461	$0.461	($0.052)	($0.052)	($0.052)
16	8 Unbundling Recovery	$0.045	$0.045	$0.045	$0.000	$0.000	$0.000	$0.045	$0.045	$0.045
17	Subtotal Commodity Related Charges per GJ	$9.790	$9.741	$9.827	($1.611)	($1.611)	($1.611)	$8.179	$8.130	$8.216
18										
19	Total Variable Cost per GJ	$11.926	$11.877	$11.963	($1.599)	($1.599)	($1.599)	$10.327	$10.278	$10.364
20										
21										
22										
23	Revelstoke Variable Cost per GJ									
24	(Includes Riders 1 & 6, Excludes Rider 8)		$16.116			$0.012			$16.128	

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Line No.	**RATE SCHEDULE 4: SEASONAL SERVICE** Particulars	**Existing Jan. 1, 2006 Interim Rates** Lower Mainland			**2006 Revenue Requirement, Gas Cost and Rider Changes** Lower Mainland			**April 1, 2006 Proposed Rates** Lower Mainland		
		Lower Mainland	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$412.00	$412.00	$412.00	$2.00	$2.00	$2.00	$414.00	$414.00	$414.00
2										
3	Delivery Charge per gigajoule									
4	(a) Off-Peak Period	$0.717	$0.717	$0.717	$0.002	$0.002	$0.002	$0.719	$0.719	$0.719
5	(b) Extension Period	$1.446	$1.446	$1.446	$0.005	$0.005	$0.005	$1.451	$1.451	$1.451
6										
7	Gas Cost Recovery Charge per GJ									
8	(a) Off-Peak Period									
9	Commodity Cost Recovery	$9.587	$9.587	$9.587	($2.012)	($2.012)	($2.012)	$7.575	$7.575	$7.575
10	Midstream Cost Recovery	$0.477	$0.442	$0.527	$0.000	$0.000	$0.000	$0.477	$0.442	$0.527
11	Subtotal Off -Peak Commodity Related Charges per GJ	$10.064	$10.029	$10.114	($2.012)	($2.012)	($2.012)	$8.052	$8.017	$8.102
12	(b) Extension Period									
13	Commodity Cost Recovery	$9.587	$9.587	$9.587	($2.012)	($2.012)	($2.012)	$7.575	$7.575	$7.575
14	Midstream Cost Recovery	$0.477	$0.442	$0.527	$0.000	$0.000	$0.000	$0.477	$0.442	$0.527
15	Subtotal Extension Commodity Related Charges per GJ	$10.064	$10.029	$10.114	($2.012)	($2.012)	($2.012)	$8.052	$8.017	$8.102
16	Unauthorized Gas Charge	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17	per GJ during peak period									
18										
19										
20	Riders: 2 Revenue shortfall - 2006Q1	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
21	3 ESM	($0.025)	($0.025)	($0.025)	$0.000	$0.000	$0.000	($0.025)	($0.025)	($0.025)
22	6 MCRA	($0.372)	($0.372)	($0.372)	$0.456	$0.456	$0.456	$0.084	$0.084	$0.084
23										
24	Total Variable Cost per GJ between									
25	(a) Off-Peak Period	$10.384	$10.349	$10.434	($1.554)	($1.554)	($1.554)	$8.830	$8.795	$8.880
26	(b) Extension Period	$11.113	$11.078	$11.163	($1.551)	($1.551)	($1.551)	$9.562	$9.527	$9.612

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Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE Particulars	Existing Jan. 1, 2006 Interim Rates Lower Mainland	Inland	Columbia	2006 Revenue Requirement, Gas Cost and Rider Changes Lower Mainland	Inland	Columbia	April 1, 2006 Proposed Rates Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$551.00	$551.00	$551.00	$2.00	$2.00	$2.00	$553.00	$553.00	$553.00
2										
3										
4	Demand Charge per GJ	$13.766	$13.766	$13.766	$0.050	$0.050	$0.050	$13.816	$13.816	$13.816
5										
6										
7	Delivery Charge per gigajoule	$0.557	$0.557	$0.557	$0.002	$0.002	$0.002	$0.559	$0.559	$0.559
8										
9	Commodity Related Charges									
10	Commodity Cost Recovery	$9.587	$9.587	$9.587	($2.012)	($2.012)	($2.012)	$7.575	$7.575	$7.575
11	Midstream Cost Recovery	$0.477	$0.442	$0.527	$0.000	$0.000	$0.000	$0.477	$0.442	$0.527
12	Subtotal Commodity Related Charges per GJ	$10.064	$10.029	$10.114	($2.012)	($2.012)	($2.012)	$8.052	$8.017	$8.102
13	Riders: 2 Revenue shortfall - 2006Q1	$0.000	$0.000	$0.000	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
14	3 ESM	($0.027)	($0.027)	($0.027)	$0.000	$0.000	$0.000	($0.027)	($0.027)	($0.027)
15	6 MCRA	($0.372)	($0.372)	($0.372)	$0.456	$0.456	$0.456	$0.084	$0.084	$0.084
16										
17	Total Variable Cost per GJ	$10.222	$10.187	$10.272	($1.551)	($1.551)	($1.551)	$8.671	$8.636	$8.721

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Line No.	RATE SCHEDULE 6: NGV - STATIONS Particulars	Existing Jan. 1, 2006 Interim Rates Lower Mainland	Inland	Columbia	2006 Revenue Requirement, Gas Cost and Rider Changes Lower Mainland	Inland	Columbia	April 1, 2006 Proposed Rates Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$58.00	$58.00	$58.00	$0.00	$0.00	$0.00	$58.00	$58.00	$58.00
2										
3										
4	Delivery Charge per gigajoule	$3.192	$3.192	$3.192	$0.011	$0.011	$0.011	$3.203	$3.203	$3.203
5										
6	Commodity Related Charges									
7	Commodity Cost Recovery	$9.438	$9.438	$9.438	($1.933)	($1.933)	($1.933)	$7.505	$7.505	$7.505
8	Midstream Cost Recovery	$0.369	$0.352	$0.352	$0.000	$0.000	$0.000	$0.369	$0.352	$0.352
9	Subtotal Commodity Related Charges per GJ	$9.807	$9.790	$9.790	($1.933)	($1.933)	($1.933)	$7.874	$7.857	$7.857
10	Riders: 2 Revenue shortfall - 2006Q1	$0.000	$0.000	$0.000	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
11	3 ESM	($0.051)	($0.051)	($0.051)	$0.000	$0.000	$0.000	($0.051)	($0.051)	($0.051)
12	6 MCRA	($0.184)	($0.184)	($0.184)	$0.451	$0.451	$0.451	$0.267	$0.267	$0.267
13										
14										
15	Total Variable Cost per GJ	$12.764	$12.747	$12.747	($1.467)	($1.467)	($1.467)	$11.297	$11.280	$11.280

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RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	Existing Rates	2006 Revenue Requirement, Gas Cost and Rider Changes	April 1, 2006 Proposed Rates
	(1)	(2)	(3)	(4)
1	Lower Mainland Service Area			
2	Basic Charge per Month	$81.70	($0.10)	$81.60
3	Minimum Charges	$125.00	$0.00	$125.00
4				
5	Delivery Charge per gigajoule	$3.192	$0.011	$3.203
6	Commodity Related Charges			
7	Commodity Cost Recovery	$9.438	($1.933)	$7.505
8	Midstream Cost Recovery	$0.369	$0.000	$0.369
9	Subtotal Commodity Related Charges per GJ	$9.807	($1.933)	$7.874
10	Compression Charge per GJ	$5.280	$0.000	$5.280
11				
12	Riders: 2 Revenue shortfall - 2006Q1	$0.000	$0.004	$0.004
13	3 ESM	($0.051)	$0.000	($0.051)
14	6 MCRA	($0.184)	$0.451	$0.267
15				
16				
17	Total Variable Cost per GJ	$18.044	($1.467)	$16.577

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Line No.	**RATE SCHEDULE 7: INTERRUPTIBLE SALES** Particulars	**Existing Jan. 1, 2006 Interim Rates** Lower Mainland	Inland	Columbia	**2006 Revenue Requirement, Gas Cost and Rider Changes** Lower Mainland	Inland	Columbia	**April 1, 2006 Proposed Rates** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$826.00	$826.00	$826.00	$3.00	$3.00	$3.00	$829.00	$829.00	$829.00
2										
3	Delivery Charge per gigajoule	$0.930	$0.930	$0.930	$0.003	$0.003	$0.003	$0.933	$0.933	$0.933
4										
5	Commodity Related Charges per GJ									
6										
7	Commodity Cost Recovery	$9.587	$9.587	$9.587	($2.012)	($2.012)	($2.012)	$7.575	$7.575	$7.575
8	Midstream Cost Recovery	$0.477	$0.442	$0.527	$0.000	$0.000	$0.000	$0.477	$0.442	$0.527
9	Subtotal Commodity Related Charges per GJ	$10.064	$10.029	$10.114	($2.012)	($2.012)	($2.012)	$8.052	$8.017	$8.102
10										
11										
12										
13										
14										
15	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
16										
17										
18										
19	Riders: 2 Revenue shortfall - 2006Q1	$0.000	$0.000	$0.000	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002
20	3 ESM	($0.016)	($0.016)	($0.016)	$0.000	$0.000	$0.000	($0.016)	($0.016)	($0.016)
21	6 MCRA	($0.372)	($0.372)	($0.372)	$0.456	$0.456	$0.456	$0.084	$0.084	$0.084
22										
23										
24										
25	Total Variable Cost per GJ	$10.606	$10.571	$10.656	($1.551)	($1.551)	($1.551)	$9.055	$9.020	$9.105

Line No.	RATE SCHEDULE 22: LARGE INDUSTRIAL T-SERVICE Particulars	Existing Jan. 1, 2006 Interim Rates Lower Mainland	Inland	Columbia	2006 Revenue Requirement and Rider Changes Lower Mainland	Inland	Columbia	April 1, 2006 Proposed Rates Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$3,442.00	$3,442.00	$3,442.00	$12.00	$12.00	$12.00	$3,454.00	$3,454.00	$3,454.00
2										
3	Delivery Charge (Interr. MTQ)	$0.689	$0.689	$0.689	$0.002	$0.002	$0.002	$0.691	$0.691	$0.691
4										
5										
6	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
7										
8										
9	Demand Surcharge per GJ	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00	$17.00	$17.00	$17.00
10										
11	Balancing Service per GJ									
12	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.30	n/a	$0.000	$0.000	$0.000	$0.30	$0.30	n/a
13	(b) between and including Nov. 1 and Mar. 31	$1.10	$1.10	n/a	$0.000	$0.000	$0.000	$1.10	$1.10	n/a
14										
15										
16	Charges per GJ for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17										
18										
19	Administration Charge	$73.00	$73.00	$73.00	$0.00	$0.00	$0.00	$73.00	$73.00	$73.00
20										
21	Riders: 2 Revenue shortfall - 2006Q1	$0.000	$0.000	$0.000	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002
22	3 ESM	($0.012)	($0.012)	($0.012)	$0.000	$0.000	$0.000	($0.012)	($0.012)	($0.012)
23										
24										
25										
26										
27	Total Variable Cost per GJ	$0.677	$0.677	$0.677	$0.004	$0.004	$0.004	$0.681	$0.681	$0.681

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RATE SCHEDULE 22A:
LARGE INDUSTRIAL T-SERVICE

Line No.	Particulars	**Existing Rates**	**2006 Revenue Requirement and Rider Changes**	**April 1, 2006 Proposed Rates**
	(1)	(2)	(3)	(4)
1	Basic Charge per Month	$4,519.00	$17.00	$4,536.00
2				
3	Delivery Charge per GJ - Firm			
4	(a) Firm DTQ	$11.053	$0.040	$11.093
5	(b) Firm MTQ	$0.078	$0.000	$0.078
6				
7	Delivery Charge per GJ - Interr MTQ	$0.883	$0.003	$0.886
8				
9	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
10				
11				
12	Demand Surchage per GJ	$17.00	$0.00	$17.00
13				
14	Balancing Service per GJ			
15	(a) between and including Apr. 1 and Oct. 31	$0.300	$0.00	$0.300
16	(b) between and including Nov. 1 and Mar. 31	$1.100	$0.00	$1.100
17				
18	Charges per GJ for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
19				
20				
21	Replacement Gas	Sumas Daily Price		Sumas Daily Price
22		plus 20 Percent		plus 20 Percent
23				
24	Administration Charge	$73.00	$0.00	$73.00
25				
26	Riders: 2 Revenue shortfall - 2006Q1	$0.000	$0.001	$0.001
27	3 ESM	($0.010)	$0.000	($0.010)
28				
29	Total Variable Cost per GJ			
30	(a) Firm MTQ	$0.068	$0.001	$0.069
31				
32	(b) Interruptible MTQ	$0.873	$0.004	$0.877

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Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE Particulars	Existing Jan. 1, 2006 Interim Rates Lower Mainland	Inland	Columbia	2006 Revenue Requirement and Rider Changes Lower Mainland	Inland	Columbia	April 1, 2006 Proposed Rates Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$124.50	$124.50	$124.50	$0.45	$0.45	$0.45	$124.95	$124.95	$124.95
2										
3										
4	Delivery Charge per GJ	$2.007	$2.007	$2.007	$0.007	$0.007	$0.007	$2.014	$2.014	$2.014
5										
6	Administration Charge	$73.00	$73.00	$73.00	$0.00	$0.00	$0.00	$73.00	$73.00	$73.00
7										
8	Sales									
9	(a) Charge per GJ for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per GJ for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per GJ for UOR Gas									
13										
14	Riders: 2 Revenue shortfall - 2006Q1	$0.000	$0.000	$0.000	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005
15	3 ESM	($0.037)	($0.037)	($0.037)	$0.000	$0.000	$0.000	($0.037)	($0.037)	($0.037)
16	5 RSAM	$0.166	$0.166	$0.166	$0.000	$0.000	$0.000	$0.166	$0.166	$0.166
17										
18										
19										
20	Total Variable Cost per GJ	$2.136	$2.136	$2.136	$0.012	$0.012	$0.012	$2.148	$2.148	$2.148

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Line No.	RATE SCHEDULE 25 GENERAL FIRM T-SERVICE Particulars	Existing Jan. 1, 2006 Interim Rates Lower Mainland	Inland	Columbia	2006 Revenue Requirement and Rider Changes Lower Mainland	Inland	Columbia	April 1, 2006 Proposed Rates Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$551.00	$551.00	$551.00	$2.00	$2.00	$2.00	$553.00	$553.00	$553.00
2										
3	Demand Charge per GJ	$13.766	$13.766	$13.766	$0.050	$0.050	$0.050	$13.816	$13.816	$13.816
4										
5										
6	Delivery Charge (Interr. MTQ)	$0.557	$0.557	$0.557	$0.002	$0.002	$0.002	$0.559	$0.559	$0.559
7										
8	Administration Charge	$73.00	$73.00	$73.00	$0.00	$0.00	$0.00	$73.00	$73.00	$73.00
9										
10	Sales									
11	(a) Charge per GJ for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per GJ for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per GJ for UOR Gas									
15										
16										
17										
18	Riders: 2 Revenue shortfall - 2006Q1	$0.000	$0.000	$0.000	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
19	3 ESM	($0.027)	($0.027)	($0.027)	$0.000	$0.000	$0.000	($0.027)	($0.027)	($0.027)
20										
21										
22	Total Variable Cost per GJ	$0.530	$0.530	$0.530	$0.005	$0.005	$0.005	$0.535	$0.535	$0.535

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Line No.	RATE SCHEDULE 27: INTERRUPTIBLE T-SERVICE	Existing Jan. 1, 2006 Interim Rates			2006 Revenue Requirement and Rider Changes			April 1, 2006 Proposed Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$826.00	$826.00	$826.00	$3.00	$3.00	$3.00	$829.00	$829.00	$829.00
2										
3										
4	Delivery Charge (Interr. MTQ)	$0.930	$0.930	$0.930	$0.003	$0.003	$0.003	$0.933	$0.933	$0.933
5										
6	Administration Charge	$73.00	$73.00	$73.00	$0.00	$0.00	$0.00	$73.00	$73.00	$73.00
7										
8	Sales									
9	(a) Charge per GJ for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per GJ for Backstopping Gas									
11	(c) Charge per GJ for UOR Gas									
12										
13	Riders: 2 Revenue shortfall - 2006Q1	$0.000	$0.000	$0.000	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002
14	3 ESM	($0.016)	($0.016)	($0.016)	$0.000	$0.000	$0.000	($0.016)	($0.016)	($0.016)
15										
16										
17	Total Variable Cost per GJ	$0.914	$0.914	$0.914	$0.005	$0.005	$0.005	$0.919	$0.919	$0.919

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Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE	Existing October 1, 2006 Rates			2007 Revenue Requirement, Gas Cost and Rider Changes			January 1, 2007 Propose Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$11.16	$11.16	$11.16	($0.22)	($0.22)	($0.22)	$10.94	$10.94	$10.94
3										
4	Delivery Charge per gigajoule	$2.791	$2.791	$2.791	($0.055)	($0.055)	($0.055)	$2.736	$2.736	$2.736
5										
6	Riders: 2 Revenue shortfall - 2006Q1	$0.010	$0.010	$0.010	($0.010)	($0.010)	($0.010)	$0.000	$0.000	$0.000
7	3 ESM	($0.063)	($0.063)	($0.063)	($0.045)	($0.045)	($0.045)	($0.108)	($0.108)	($0.108)
8	5 RSAM	$0.166	$0.166	$0.166	($0.021)	($0.021)	($0.021)	$0.145	$0.145	$0.145
9	Subtotal Delivery Margin Related Charges per GJ	$2.904	$2.904	$2.904	($0.131)	($0.131)	($0.131)	$2.773	$2.773	$2.773
10										
11	Commodity Related Charges									
12	Commodity Gas Cost Recovery Charge per GJ	$7.662	$7.662	$7.662	$0.000	$0.000	$0.000	$7.662	$7.662	$7.662
13	Midstream Gas Cost Recovery Charge per GJ	$0.613	$0.556	$0.642	$0.246	$0.294	$0.270	$0.859	$0.850	$0.912
14	Riders: 1 Propane Surcharge (Revelstoke only)		$8.183			($3.136)			$5.047	
15	6 MCRA	($0.142)	($0.142)	($0.142)	$0.142	$0.142	$0.142	$0.000	$0.000	$0.000
16	9 Stable Rate Recovery	$0.004	$0.004	$0.004	($0.003)	($0.003)	($0.003)	$0.001	$0.001	$0.001
17	Subtotal Commodity Related Charges per GJ	$8.137	$8.080	$8.166	$0.385	$0.433	$0.409	$8.522	$8.513	$8.575
18										
19	Total Variable Cost per GJ	$11.041	$10.984	$11.070	$0.254	$0.302	$0.278	$11.295	$11.286	$11.348
20										
21	Revelstoke Variable Cost per GJ									
22	(Includes Riders 1 & 6, Excludes Rider 9)		$19.163			($2.831)			$16.332	

Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE	Existing October 1, 2006 Rates			2007 Revenue Requirement, Gas Cost and Rider Changes			January 1, 2007 Propose Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$23.42	$23.42	$23.42	($0.46)	($0.46)	($0.46)	$22.96	$22.96	$22.96
3										
4	Delivery Charge per gigajoule	$2.337	$2.337	$2.337	($0.046)	($0.046)	($0.046)	$2.291	$2.291	$2.291
5										
6	Riders: 2 Revenue shortfall - 2006Q1	$0.008	$0.008	$0.008	($0.008)	($0.008)	($0.008)	$0.000	$0.000	$0.000
7	3 ESM	($0.049)	($0.049)	($0.049)	($0.035)	($0.035)	($0.035)	($0.084)	($0.084)	($0.084)
8	5 RSAM	$0.166	$0.166	$0.166	($0.021)	($0.021)	($0.021)	$0.145	$0.145	$0.145
9	Subtotal Delivery Margin Related Charges per GJ	$2.462	$2.462	$2.462	($0.110)	($0.110)	($0.110)	$2.352	$2.352	$2.352
10										
11	Commodity Related Charges									
12	Commodity Gas Cost Recovery Charge per GJ	$7.673	$7.673	$7.673	$0.000	$0.000	$0.000	$7.673	$7.673	$7.673
13	Midstream Gas Cost Recovery Charge per GJ	$0.630	$0.570	$0.656	$0.235	$0.286	$0.262	$0.865	$0.856	$0.918
14	Riders: 1 Propane Surcharge (Revelstoke only)		$7.096			($3.157)			$3.939	
15	6 MCRA	($0.171)	($0.171)	($0.171)	$0.171	$0.171	$0.171	$0.000	$0.000	$0.000
16	8 Unbundling Recovery	$0.045	$0.045	$0.045	$0.008	$0.008	$0.008	$0.053	$0.053	$0.053
17	Subtotal Commodity Related Charges per GJ	$8.177	$8.117	$8.203	$0.414	$0.465	$0.441	$8.591	$8.582	$8.644
18										
19										
20	Total Variable Cost per GJ	$10.639	$10.579	$10.665	$0.304	$0.355	$0.331	$10.943	$10.934	$10.996
21										
22	Revelstoke Variable Cost per GJ									
23	(Includes Riders 1 & 6, Excludes Rider 8)		$17.630			($2.810)			$14.820	

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Line No.	**RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE** Particulars	**Existing October 1, 2006 Rates** Lower Mainland	Inland	Columbia	**2007 Revenue Requirement, Gas Cost and Rider Changes** Lower Mainland	Inland	Columbia	**January 1, 2007 Propose Rates** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$124.95	$124.95	$124.95	($2.47)	($2.47)	($2.47)	$122.48	$122.48	$122.48
3										
4	Delivery Charge per gigajoule	$2.014	$2.014	$2.014	($0.040)	($0.040)	($0.040)	$1.974	$1.974	$1.974
5										
6	Riders: 2 Revenue shortfall - 2006Q1	$0.005	$0.005	$0.005	($0.005)	($0.005)	($0.005)	$0.000	$0.000	$0.000
7	3 ESM	($0.037)	($0.037)	($0.037)	($0.028)	($0.028)	($0.028)	($0.065)	($0.065)	($0.065)
8	5 RSAM	$0.166	$0.166	$0.166	($0.021)	($0.021)	($0.021)	$0.145	$0.145	$0.145
9	Subtotal Delivery Margin Related Charges per GJ	$2.148	$2.148	$2.148	($0.094)	($0.094)	($0.094)	$2.054	$2.054	$2.054
10										
11	Commodity Related Charges									
12	Commodity Cost Recovery	$7.627	$7.627	$7.627	$0.000	$0.000	$0.000	$7.627	$7.627	$7.627
13	Midstream Cost Recovery	$0.559	$0.510	$0.596	$0.202	$0.246	$0.221	$0.761	$0.756	$0.817
14	Riders: 1 Propane Surcharge (Revelstoke only)		$7.083			($2.998)			$4.085	
15	6 MCRA	($0.052)	($0.052)	($0.052)	$0.052	$0.052	$0.052	$0.000	$0.000	$0.000
16	8 Unbundling Recovery	$0.045	$0.045	$0.045	$0.008	$0.008	$0.008	$0.053	$0.053	$0.053
17	Subtotal Commodity Related Charges per GJ	$8.179	$8.130	$8.216	$0.262	$0.306	$0.281	$8.441	$8.436	$8.497
18										
19	Total Variable Cost per GJ	$10.327	$10.278	$10.364	$0.168	$0.212	$0.187	$10.495	$10.490	$10.551
20										
21										
22										
23	Revelstoke Variable Cost per GJ									
24	(Includes Riders 1 & 6, Excludes Rider 8)		$17.316			($2.794)			$14.522	

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Line No.	RATE SCHEDULE 4: SEASONAL SERVICE	Existing October 1, 2006 Rates			2007 Revenue Requirement, Gas Cost and Rider Changes			January 1, 2007 Propose Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$414.00	$414.00	$414.00	($8.00)	($8.00)	($8.00)	$406.00	$406.00	$406.00
2										
3	Delivery Charge per gigajoule									
4	(a) Off-Peak Period	$0.719	$0.719	$0.719	($0.014)	($0.014)	($0.014)	$0.705	$0.705	$0.705
5	(b) Extension Period	$1.451	$1.451	$1.451	($0.029)	($0.029)	($0.029)	$1.422	$1.422	$1.422
6										
7	Gas Cost Recovery Charge per GJ									
8	(a) Off-Peak Period									
9	Commodity Cost Recovery	$7.575	$7.575	$7.575	$0.000	$0.000	$0.000	$7.575	$7.575	$7.575
10	Midstream Cost Recovery	$0.477	$0.442	$0.527	$0.137	$0.173	$0.149	$0.614	$0.615	$0.676
11	Subtotal Off -Peak Commodity Related Charges per GJ	$8.052	$8.017	$8.102	$0.137	$0.173	$0.149	$8.189	$8.190	$8.251
12	(b) Extension Period									
13	Commodity Cost Recovery	$7.575	$7.575	$7.575	$0.000	$0.000	$0.000	$7.575	$7.575	$7.575
14	Midstream Cost Recovery	$0.477	$0.442	$0.676	$0.137	$0.173	$0.000	$0.614	$0.615	$0.676
15	Subtotal Extension Commodity Related Charges per GJ	$8.052	$8.017	$8.251	$0.137	$0.173	$0.000	$8.189	$8.190	$8.251
16	Unauthorized Gas Charge	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17	per GJ during peak period									
18										
19										
20	Riders: 2 Revenue shortfall - 2006Q1	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
21	3 ESM	($0.025)	($0.025)	($0.025)	($0.012)	($0.012)	($0.012)	($0.037)	($0.037)	($0.037)
22	6 MCRA	$0.084	$0.084	$0.084	($0.084)	($0.084)	($0.084)	$0.000	$0.000	$0.000
23										
24	Total Variable Cost per GJ between									
25	(a) Off-Peak Period	$8.830	$8.795	$8.880	$0.027	$0.063	$0.039	$8.857	$8.858	$8.919
26	(b) Extension Period	$9.562	$9.527	$9.761	$0.012	$0.048	($0.125)	$9.574	$9.575	$9.636

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Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE	Existing October 1, 2006 Rates			2007 Revenue Requirement, Gas Cost and Rider Changes			January 1, 2007 Propose Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$553.00	$553.00	$553.00	($11.00)	($11.00)	($11.00)	$542.00	$542.00	$542.00
2										
3										
4	Demand Charge per GJ	$13.816	$13.816	$13.816	($0.273)	($0.273)	($0.273)	$13.543	$13.543	$13.543
5										
6										
7	Delivery Charge per gigajoule	$0.559	$0.559	$0.559	($0.011)	($0.011)	($0.011)	$0.548	$0.548	$0.548
8										
9	Commodity Related Charges									
10	Commodity Cost Recovery	$7.575	$7.575	$7.575	$0.000	$0.000	$0.000	$7.575	$7.575	$7.575
11	Midstream Cost Recovery	$0.477	$0.442	$0.527	$0.137	$0.173	$0.149	$0.614	$0.615	$0.676
12	Subtotal Commodity Related Charges per GJ	$8.052	$8.017	$8.102	$0.137	$0.173	$0.149	$8.189	$8.190	$8.251
13	Riders: 2 Revenue shortfall - 2006Q1	$0.003	$0.003	$0.003	($0.003)	($0.003)	($0.003)	$0.000	$0.000	$0.000
14	3 ESM	($0.027)	($0.027)	($0.027)	($0.020)	($0.020)	($0.020)	($0.047)	($0.047)	($0.047)
15	6 MCRA	$0.084	$0.084	$0.084	($0.084)	($0.084)	($0.084)	$0.000	$0.000	$0.000
16										
17	Total Variable Cost per GJ	$8.671	$8.636	$8.721	$0.019	$0.055	$0.031	$8.690	$8.691	$8.752

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Line No.	RATE SCHEDULE 6: NGV - STATIONS Particulars	Existing October 1, 2006 Rates Lower Mainland	Inland	Columbia	2007 Revenue Requirement, Gas Cost and Rider Changes Lower Mainland	Inland	Columbia	January 1, 2007 Propose Rates Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$58.00	$58.00	$58.00	($1.00)	($1.00)	($1.00)	$57.00	$57.00	$57.00
2										
3										
4	Delivery Charge per gigajoule	$3.203	$3.203	$3.203	($0.063)	($0.063)	($0.063)	$3.140	$3.140	$3.140
5										
6	Commodity Related Charges									
7	Commodity Cost Recovery	$7.505	$7.505	$7.505	$0.000	$0.000	$0.000	$7.505	$7.505	$7.505
8	Midstream Cost Recovery	$0.369	$0.352	$0.352	$0.051	$0.072	$0.072	$0.420	$0.424	$0.424
9	Subtotal Commodity Related Charges per GJ	$7.874	$7.857	$7.857	$0.051	$0.072	$0.072	$7.925	$7.929	$7.929
10	Riders: 2 Revenue shortfall - 2006Q1	$0.004	$0.004	$0.004	($0.004)	($0.004)	($0.004)	$0.000	$0.000	$0.000
11	3 ESM	($0.051)	($0.051)	($0.051)	($0.039)	($0.039)	($0.039)	($0.090)	($0.090)	($0.090)
12	6 MCRA	$0.267	$0.267	$0.267	($0.267)	($0.267)	($0.267)	$0.000	$0.000	$0.000
13										
14										
15	Total Variable Cost per GJ	$11.297	$11.280	$11.280	($0.322)	($0.301)	($0.301)	$10.975	$10.979	$10.979

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RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars		Existing Rates	2007 Revenue Requirement, Gas Cost and Rider Changes	January 1, 2007 Propose Rates
	(1)		(2)	(3)	(4)
1	Lower Mainland Service Area				
2	Basic Charge per Month		$81.70	($1.70)	$80.00
3	Minimum Charges		$125.00	$0.00	$125.00
4					
5	Delivery Charge per gigajoule		$3.203	($0.10)	$3.103
6	Commodity Related Charges				
7	Commodity Cost Recovery		$7.505	$0.000	$7.505
8	Midstream Cost Recovery		$0.369	$0.051	$0.420
9	Subtotal Commodity Related Charges per GJ		$7.874	$0.051	$7.925
10	Compression Charge per GJ		$5.280	$0.000	$5.280
11					
12	Riders:	2 Revenue shortfall - 2006Q1	$0.004	($0.004)	$0.000
13		3 ESM	($0.051)	($0.039)	($0.090)
14		6 MCRA	$0.267	($0.267)	$0.000
15					
16					
17	Total Variable Cost per GJ		$16.577	($0.359)	$16.218

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Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES	Existing October 1, 2006 Rates			2007 Revenue Requirement, Gas Cost and Rider Changes			January 1, 2007 Propose Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$829.00	$829.00	$829.00	($16.00)	($16.00)	($16.00)	$813.00	$813.00	$813.00
2										
3	Delivery Charge per gigajoule	$0.933	$0.933	$0.933	($0.018)	($0.018)	($0.018)	$0.915	$0.915	$0.915
4										
5	Commodity Related Charges per GJ									
6										
7	Commodity Cost Recovery	$7.575	$7.575	$7.575	$0.000	$0.000	$0.000	$7.575	$7.575	$7.575
8	Midstream Cost Recovery	$0.477	$0.442	$0.527	$0.137	$0.173	$0.149	$0.614	$0.615	$0.676
9	Subtotal Commodity Related Charges per GJ	$8.052	$8.017	$8.102	$0.137	$0.173	$0.149	$8.189	$8.190	$8.251
10										
11										
12										
13										
14										
15	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
16										
17										
18										
19	Riders: 2 Revenue shortfall - 2006Q1	$0.002	$0.002	$0.002	($0.002)	($0.002)	($0.002)	$0.000	$0.000	$0.000
20	3 ESM	($0.016)	($0.016)	($0.016)	($0.013)	($0.013)	($0.013)	($0.029)	($0.029)	($0.029)
21	6 MCRA	$0.084	$0.084	$0.084	($0.084)	($0.084)	($0.084)	$0.000	$0.000	$0.000
22										
23										
24										
25	Total Variable Cost per GJ	$9.055	$9.020	$9.105	$0.020	$0.056	$0.032	$9.075	$9.076	$9.137

Line No.	RATE SCHEDULE 22: LARGE INDUSTRIAL T-SERVICE	Existing October 1, 2006 Rates			2007 Revenue Requirement and Rider Changes			January 1, 2007 Propose Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$3,454.00	$3,454.00	$3,454.00	($68.00)	($68.00)	($68.00)	$3,386.00	$3,386.00	$3,386.00
2										
3	Delivery Charge (Interr. MTQ)	$0.691	$0.691	$0.691	($0.014)	($0.014)	($0.014)	$0.677	$0.677	$0.677
4										
5										
6	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
7										
8										
9	Demand Surcharge per GJ	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00	$17.00	$17.00	$17.00
10										
11	Balancing Service per GJ									
12	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.30	n/a	$0.000	$0.000	$0.000	$0.30	$0.30	n/a
13	(b) between and including Nov. 1 and Mar. 31	$1.10	$1.10	n/a	$0.000	$0.000	$0.000	$1.10	$1.10	n/a
14										
15										
16	Charges per GJ for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17										
18										
19	Administration Charge	$73.00	$73.00	$73.00	($1.00)	($1.00)	($1.00)	$72.00	$72.00	$72.00
20										
21	Riders: 2 Revenue shortfall - 2006Q1	$0.002	$0.002	$0.002	($0.002)	($0.002)	($0.002)	$0.000	$0.000	$0.000
22	3 ESM	($0.012)	($0.012)	($0.012)	($0.009)	($0.009)	($0.009)	($0.021)	($0.021)	($0.021)
23										
24										
25										
26										
27	Total Variable Cost per GJ	$0.681	$0.681	$0.681	($0.025)	($0.025)	($0.025)	$0.656	$0.656	$0.656

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RATE SCHEDULE 22A:
LARGE INDUSTRIAL T-SERVICE

Line No.	Particulars	Existing Rates	2007 Revenue Requirement and Rider Changes	January 1, 2007 Propose Rates
	(1)	(2)	(3)	(4)
1	Basic Charge per Month	$4,536.00	($90.00)	$4,446.00
2				
3	Delivery Charge per GJ - Firm			
4	(a) Firm DTQ	$11.093	($0.220)	$10.873
5	(b) Firm MTQ	$0.078	($0.002)	$0.076
6				
7	Delivery Charge per GJ - Interr MTQ	$0.886	($0.018)	$0.868
8				
9	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
10				
11				
12	Demand Surchage per GJ	$17.00	$0.00	$17.00
13				
14	Balancing Service per GJ			
15	(a) between and including Apr. 1 and Oct. 31	$0.300	$0.00	$0.300
16	(b) between and including Nov. 1 and Mar. 31	$1.100	$0.00	$1.100
17				
18	Charges per GJ for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
19				
20				
21	Replacement Gas	Sumas Daily Price		Sumas Daily Price
22		plus 20 Percent		plus 20 Percent
23				
24	Administration Charge	$73.00	($1.00)	$72.00
25				
26	Riders: 2 Revenue shortfall - 2006Q1	$0.001	($0.001)	$0.000
27	3 ESM	($0.010)	($0.006)	($0.016)
28				
29	Total Variable Cost per GJ			
30	(a) Firm MTQ	$0.069	($0.009)	$0.060
31				
32	(b) Interruptible MTQ	$0.877	($0.025)	$0.852

Line No.	RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE	Existing October 1, 2006 Rates		2007 Revenue Requirement and Rider Changes		January 1, 2007 Propose Rates	
	Particulars	Columbia Except Elkview	Elkview Coal	Columbia Except Elkview	Elkview Coal	Columbia Except Elkview	Elkview Coal
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Basic Charge per Month	$4,278.00	$4,278.00	($85.00)	($85.00)	$4,193.00	$4,193.00
2							
3	Delivery Charge per GJ - Firm						
4	(a) Firm DTQ	$7.068	$1.605	($0.140)	($0.032)	$6.928	$1.573
5	(b) Firm MTQ	$0.076	$0.076	($0.002)	($0.002)	$0.074	$0.074
6							
7	Delivery Charge per GJ - Interr MTQ						
8	(a) between and including Apr. 1 and Oct. 31	$0.704	$0.175	($0.014)	($0.003)	$0.690	$0.172
9	(b) between and including Nov. 1 and Mar. 31	$1.015	$0.252	($0.020)	($0.005)	$0.995	$0.247
10							
11	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
12							
13							
14	Demand Surcharge per GJ	$17.00	$17.00	$0.00	$0.00	$17.00	$17.00
15							
16	Charges per GJ for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
17							
18							
19							
20	Administration Charge	$73.00	$73.00	($1.00)	($1.00)	$72.00	$72.00
21							
22	Riders: 2 Revenue shortfall - 2006Q1	$0.001	$0.000	($0.001)	$0.000	$0.000	$0.000
23	ESM	($0.008)	($0.004)	($0.010)	($0.002)	($0.018)	($0.006)
24							
25							
26							
27							
28							
29							
30	Total Variable Cost per GJ						
31	(a) Firm MTQ	$0.069	$0.072	($0.013)	($0.004)	$0.056	$0.068
32	(b) Interruptible MTQ - Summer	$0.697	$0.171	($0.025)	($0.005)	$0.672	$0.166
33	- Winter	$1.008	$0.248	($0.031)	($0.007)	$0.977	$0.241
34							

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Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE	Existing October 1, 2006 Rates			2007 Revenue Requirement and Rider Changes			January 1, 2007 Propose Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$124.95	$124.95	$124.95	($2.47)	($2.47)	($2.47)	$122.48	$122.48	$122.48
2										
3										
4	Delivery Charge per GJ	$2.014	$2.014	$2.014	($0.040)	($0.040)	($0.040)	$1.974	$1.974	$1.974
5										
6	Administration Charge	$73.00	$73.00	$73.00	($1.00)	($1.00)	($1.00)	$72.00	$72.00	$72.00
7										
8	Sales									
9	(a) Charge per GJ for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per GJ for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per GJ for UOR Gas									
13										
14	Riders: 2 Revenue shortfall - 2006Q1	$0.005	$0.005	$0.005	($0.005)	($0.005)	($0.005)	$0.000	$0.000	$0.000
15	3 ESM	($0.037)	($0.037)	($0.037)	($0.028)	($0.028)	($0.028)	($0.065)	($0.065)	($0.065)
16	5 RSAM	$0.166	$0.166	$0.166	($0.021)	($0.021)	($0.021)	$0.145	$0.145	$0.145
17										
18										
19										
20	Total Variable Cost per GJ	$2.148	$2.148	$2.148	($0.094)	($0.094)	($0.094)	$2.054	$2.054	$2.054

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Line No.	**RATE SCHEDULE 25 GENERAL FIRM T-SERVICE** Particulars	**Existing October 1, 2006 Rates** Lower Mainland	Inland	Columbia	**2007 Revenue Requirement and Rider Changes** Lower Mainland	Inland	Columbia	**January 1, 2007 Propose Rates** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$553.00	$553.00	$553.00	($11.00)	($11.00)	($11.00)	$542.00	$542.00	$542.00
2										
3	Demand Charge per GJ	$13.816	$13.816	$13.816	($0.273)	($0.273)	($0.273)	$13.543	$13.543	$13.543
4										
5										
6	Delivery Charge (Interr. MTQ)	$0.559	$0.559	$0.559	($0.011)	($0.011)	($0.011)	$0.548	$0.548	$0.548
7										
8	Administration Charge	$73.00	$73.00	$73.00	($1.00)	($1.00)	($1.00)	$72.00	$72.00	$72.00
9										
10	Sales									
11	(a) Charge per GJ for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per GJ for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per GJ for UOR Gas									
15										
16										
17										
18	Riders: 2 Revenue shortfall - 2006Q1	$0.003	$0.003	$0.003	($0.003)	($0.003)	($0.003)	$0.000	$0.000	$0.000
19	3 ESM	($0.027)	($0.027)	($0.027)	($0.020)	($0.020)	($0.020)	($0.047)	($0.047)	($0.047)
20										
21										
22	Total Variable Cost per GJ	$0.535	$0.535	$0.535	($0.034)	($0.034)	($0.034)	$0.501	$0.501	$0.501

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Line No.	**RATE SCHEDULE 27: INTERRUPTIBLE T-SERVICE** Particulars	**Existing October 1, 2006 Rates** Lower Mainland	Inland	Columbia	**2007 Revenue Requirement and Rider Changes** Lower Mainland	Inland	Columbia	**January 1, 2007 Propose Rates** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$829.00	$829.00	$829.00	($16.00)	($16.00)	($16.00)	$813.00	$813.00	$813.00
2										
3										
4	Delivery Charge (Interr. MTQ)	$0.933	$0.933	$0.933	($0.018)	($0.018)	($0.018)	$0.915	$0.915	$0.915
5										
6	Administration Charge	$73.00	$73.00	$73.00	($1.00)	($1.00)	($1.00)	$72.00	$72.00	$72.00
7										
8	Sales									
9	(a) Charge per GJ for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per GJ for Backstopping Gas									
11	(c) Charge per GJ for UOR Gas									
12										
13	Riders: 2 Revenue shortfall - 2006Q1	$0.002	$0.002	$0.002	($0.002)	($0.002)	($0.002)	$0.000	$0.000	$0.000
14	3 ESM	($0.016)	($0.016)	($0.016)	($0.013)	($0.013)	($0.013)	($0.029)	($0.029)	($0.029)
15										
16										
17	Total Variable Cost per GJ	$0.919	$0.919	$0.919	($0.033)	($0.033)	($0.033)	$0.886	$0.886	$0.886

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CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
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Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE	Existing Rates			Commodity Related Charges Changes			October 1, 2007 Approved Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$10.94	$10.94	$10.94	$0.00	$0.00	$0.00	$10.94	$10.94	$10.94
3										
4	Delivery Charge per gigajoule	$2.736	$2.736	$2.736	$0.000	$0.000	$0.000	$2.736	$2.736	$2.736
5										
6	Riders: 2 (Reserved for future use)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	3 ESM	($0.108)	($0.108)	($0.108)	$0.000	$0.000	$0.000	($0.108)	($0.108)	($0.108)
8	5 RSAM	$0.145	$0.145	$0.145	$0.000	$0.000	$0.000	$0.145	$0.145	$0.145
9	Subtotal Delivery Margin Related Charges per GJ	$2.773	$2.773	$2.773	$0.000	$0.000	$0.000	$2.773	$2.773	$2.773
10										
11	Commodity Related Charges									
12	Commodity Gas Cost Recovery Charge per GJ	$7.662	$7.662	$7.662	($0.736)	($0.736)	($0.736)	$6.926	$6.926	$6.926
13	Midstream Gas Cost Recovery Charge per GJ	$0.859	$0.850	$0.912	$0.000	$0.000	$0.000	$0.859	$0.850	$0.912
14	Riders: 1 Propane Surcharge (Revelstoke only)		$6.227			$0.736			$6.963	
15	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16	9 Stable Rate Recovery	$0.001	$0.001	$0.001	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001
17	Subtotal Commodity Related Charges per GJ	$8.522	$8.513	$8.575	($0.736)	($0.736)	($0.736)	$7.786	$7.777	$7.839
18										
19	Total Variable Cost per GJ	$11.295	$11.286	$11.348	($0.736)	($0.736)	($0.736)	$10.559	$10.550	$10.612
20										
21	Revelstoke Variable Cost per GJ									
22	(Includes Riders 1 & 6, Excludes Rider 9)		$17.512			$0.000			$17.512	

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Line No.	**RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE** Particulars	**Existing Rates** Lower Mainland	Inland	Columbia	**Commodity Related Charges Changes** Lower Mainland	Inland	Columbia	**October 1, 2007 Approved Rates** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$22.96	$22.96	$22.96	$0.00	$0.00	$0.00	$22.96	$22.96	$22.96
3										
4	Delivery Charge per gigajoule	$2.291	$2.291	$2.291	$0.000	$0.000	$0.000	$2.291	$2.291	$2.291
5										
6	Riders: 2 (Reserved for future use)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	3 ESM	($0.084)	($0.084)	($0.084)	$0.000	$0.000	$0.000	($0.084)	($0.084)	($0.084)
8	5 RSAM	$0.145	$0.145	$0.145	$0.000	$0.000	$0.000	$0.145	$0.145	$0.145
9	Subtotal Delivery Margin Related Charges per GJ	$2.352	$2.352	$2.352	$0.000	$0.000	$0.000	$2.352	$2.352	$2.352
10										
11	Commodity Related Charges									
12	Commodity Gas Cost Recovery Charge per GJ	$7.673	$7.673	$7.673	($0.745)	($0.745)	($0.745)	$6.928	$6.928	$6.928
13	Midstream Gas Cost Recovery Charge per GJ	$0.865	$0.856	$0.918	$0.000	$0.000	$0.000	$0.865	$0.856	$0.918
14	Riders: 1 Propane Surcharge (Revelstoke only)		$5.119			$0.745			$5.864	
15	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16	8 Unbundling Recovery	$0.053	$0.053	$0.053	$0.000	$0.000	$0.000	$0.053	$0.053	$0.053
17	Subtotal Commodity Related Charges per GJ	$8.591	$8.582	$8.644	($0.745)	($0.745)	($0.745)	$7.846	$7.837	$7.899
18										
19										
20	Total Variable Cost per GJ	$10.943	$10.934	$10.996	($0.745)	($0.745)	($0.745)	$10.198	$10.189	$10.251
21										
22	Revelstoke Variable Cost per GJ									
23	(Includes Riders 1 & 6, Excludes Rider 8)		$16.000			$0.000			$16.000	

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Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE	Existing Rates			Commodity Related Charges Changes			October 1, 2007 Approved Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$122.48	$122.48	$122.48	$0.00	$0.00	$0.00	$122.48	$122.48	$122.48
3										
4	Delivery Charge per gigajoule	$1.974	$1.974	$1.974	$0.000	$0.000	$0.000	$1.974	$1.974	$1.974
5										
6	Riders: 2 (Reserved for future use)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	3 ESM	($0.065)	($0.065)	($0.065)	$0.000	$0.000	$0.000	($0.065)	($0.065)	($0.065)
8	5 RSAM	$0.145	$0.145	$0.145	$0.000	$0.000	$0.000	$0.145	$0.145	$0.145
9	Subtotal Delivery Margin Related Charges per GJ	$2.054	$2.054	$2.054	$0.000	$0.000	$0.000	$2.054	$2.054	$2.054
10										
11	Commodity Related Charges									
12	Commodity Cost Recovery	$7.627	$7.627	$7.627	($0.711)	($0.711)	($0.711)	$6.916	$6.916	$6.916
13	Midstream Cost Recovery	$0.761	$0.756	$0.817	$0.000	$0.000	$0.000	$0.761	$0.756	$0.817
14	Riders: 1 Propane Surcharge (Revelstoke only)		$5.265			$0.711			$5.976	
15	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16	8 Unbundling Recovery	$0.053	$0.053	$0.053	$0.000	$0.000	$0.000	$0.053	$0.053	$0.053
17	Subtotal Commodity Related Charges per GJ	$8.441	$8.436	$8.497	($0.711)	($0.711)	($0.711)	$7.730	$7.725	$7.786
18										
19	Total Variable Cost per GJ	$10.495	$10.490	$10.551	($0.711)	($0.711)	($0.711)	$9.784	$9.779	$9.840
20										
21										
22										
23	Revelstoke Variable Cost per GJ									
24	(Includes Riders 1 & 6, Excludes Rider 8)		$15.702			$0.000			$15.702	

Line No.	RATE SCHEDULE 4: SEASONAL SERVICE	Existing Rates			Commodity Related Charges Changes			October 1, 2007 Approved Rates		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$406.00	$406.00	$406.00	$0.00	$0.00	$0.00	$406.00	$406.00	$406.00
2										
3	Delivery Charge per gigajoule									
4	(a) Off-Peak Period	$0.705	$0.705	$0.705	$0.000	$0.000	$0.000	$0.705	$0.705	$0.705
5	(b) Extension Period	$1.422	$1.422	$1.422	$0.000	$0.000	$0.000	$1.422	$1.422	$1.422
6										
7	Gas Cost Recovery Charge per GJ									
8	(a) Off-Peak Period									
9	Commodity Cost Recovery	$7.575	$7.575	$7.575	($0.673)	($0.673)	($0.673)	$6.902	$6.902	$6.902
10	Midstream Cost Recovery	$0.614	$0.615	$0.676	$0.000	$0.000	$0.000	$0.614	$0.615	$0.676
11	Subtotal Off -Peak Commodity Related Charges per GJ	$8.189	$8.190	$8.251	($0.673)	($0.673)	($0.673)	$7.516	$7.517	$7.578
12	(b) Extension Period									
13	Commodity Cost Recovery	$7.575	$7.575	$6.902	($0.673)	($0.673)	$0.000	$6.902	$6.902	$6.902
14	Midstream Cost Recovery	$0.614	$0.615	$0.676	$0.000	$0.000	$0.000	$0.614	$0.615	$0.676
15	Subtotal Extension Commodity Related Charges per GJ	$8.189	$8.190	$7.578	($0.673)	($0.673)	$0.000	$7.516	$7.517	$7.578
16	Unauthorized Gas Charge	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17	per GJ during peak period									
18										
19										
20	Riders: 2 (Reserved for future use)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
21	3 ESM	($0.037)	($0.037)	($0.037)	$0.000	$0.000	$0.000	($0.037)	($0.037)	($0.037)
22	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
23										
24	Total Variable Cost per GJ between									
25	(a) Off-Peak Period	$8.857	$8.858	$8.919	($0.673)	($0.673)	($0.673)	$8.184	$8.185	$8.246
26	(b) Extension Period	$9.574	$9.575	$8.963	($0.673)	($0.673)	$0.000	$8.901	$8.902	$8.963

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
EFFECTIVE OCTOBER 1, 2007
BCUC ORDER NO. G-105-07

Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE Particulars	Existing Rates Lower Mainland	Existing Rates Inland	Existing Rates Columbia	Commodity Related Charges Changes Lower Mainland	Commodity Related Charges Changes Inland	Commodity Related Charges Changes Columbia	October 1, 2007 Approved Rates Lower Mainland	October 1, 2007 Approved Rates Inland	October 1, 2007 Approved Rates Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$542.00	$542.00	$542.00	$0.00	$0.00	$0.00	$542.00	$542.00	$542.00
2										
3										
4	Demand Charge per GJ	$13.543	$13.543	$13.543	$0.000	$0.000	$0.000	$13.543	$13.543	$13.543
5										
6										
7	Delivery Charge per gigajoule	$0.548	$0.548	$0.548	$0.000	$0.000	$0.000	$0.548	$0.548	$0.548
8										
9	Commodity Related Charges									
10	Commodity Cost Recovery	$7.575	$7.575	$7.575	($0.673)	($0.673)	($0.673)	$6.902	$6.902	$6.902
11	Midstream Cost Recovery	$0.614	$0.615	$0.676	$0.000	$0.000	$0.000	$0.614	$0.615	$0.676
12	Subtotal Commodity Related Charges per GJ	$8.189	$8.190	$8.251	($0.673)	($0.673)	($0.673)	$7.516	$7.517	$7.578
13	Riders: 2 (Reserved for future use)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	3 ESM	($0.047)	($0.047)	($0.047)	$0.000	$0.000	$0.000	($0.047)	($0.047)	($0.047)
15	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16										
17	Total Variable Cost per GJ	$8.690	$8.691	$8.752	($0.673)	($0.673)	($0.673)	$8.017	$8.018	$8.079

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
EFFECTIVE OCTOBER 1, 2007
BCUC ORDER NO. G-105-07

Line No.	RATE SCHEDULE 6: NGV - STATIONS Particulars	Existing Rates Lower Mainland	Existing Rates Inland	Existing Rates Columbia	Commodity Related Charges Changes Lower Mainland	Commodity Related Charges Changes Inland	Commodity Related Charges Changes Columbia	October 1, 2007 Approved Rates Lower Mainland	October 1, 2007 Approved Rates Inland	October 1, 2007 Approved Rates Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$57.00	$57.00	$57.00	$0.00	$0.00	$0.00	$57.00	$57.00	$57.00
2										
3										
4	Delivery Charge per gigajoule	$3.140	$3.140	$3.140	$0.000	$0.000	$0.000	$3.140	$3.140	$3.140
5										
6	Commodity Related Charges									
7	Commodity Cost Recovery	$7.505	$7.505	$7.505	($0.622)	($0.622)	($0.622)	$6.883	$6.883	$6.883
8	Midstream Cost Recovery	$0.420	$0.424	$0.424	$0.000	$0.000	$0.000	$0.420	$0.424	$0.424
9	Subtotal Commodity Related Charges per GJ	$7.925	$7.929	$7.929	($0.622)	($0.622)	($0.622)	$7.303	$7.307	$7.307
10	Riders: 2 (Reserved for future use)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
11	3 ESM	($0.090)	($0.090)	($0.090)	$0.000	$0.000	$0.000	($0.090)	($0.090)	($0.090)
12	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
13										
14										
15	Total Variable Cost per GJ	$10.975	$10.979	$10.979	($0.622)	($0.622)	($0.622)	$10.353	$10.357	$10.357

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
EFFECTIVE OCTOBER 1, 2007
BCUC ORDER NO. G-105-07

RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	**Existing Rates**	**Commodity Related Charges Changes**	**October 1, 2007 Approved Rates**
	(1)	(2)	(3)	(4)
1	Lower Mainland Service Area			
2	Basic Charge per Month	$80.00	$0.00	$80.00
3	Minimum Charges	$125.00	$0.00	$125.00
4				
5	Delivery Charge per gigajoule	$3.103	$0.00	$3.103
6	Commodity Related Charges			
7	Commodity Cost Recovery	$7.505	($0.622)	$6.883
8	Midstream Cost Recovery	$0.420	$0.000	$0.420
9	Subtotal Commodity Related Charges per GJ	$7.925	($0.622)	$7.303
10	Compression Charge per GJ	$5.280	$0.000	$5.280
11				
12	Riders: 2 (Reserved for future use)	$0.000	$0.000	$0.000
13	3 ESM	($0.090)	$0.000	($0.090)
14	6 MCRA	$0.000	$0.000	$0.000
15				
16				
17	Total Variable Cost per GJ	$16.218	($0.622)	$15.596

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
EFFECTIVE OCTOBER 1, 2007
BCUC ORDER NO. G-105-07

Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES Particulars	Existing Rates Lower Mainland	 Inland	 Columbia	Commodity Related Charges Changes Lower Mainland	 Inland	 Columbia	October 1, 2007 Approved Rates Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$813.00	$813.00	$813.00	$0.00	$0.00	$0.00	$813.00	$813.00	$813.00
2										
3	Delivery Charge per gigajoule	$0.915	$0.915	$0.915	$0.000	$0.000	$0.000	$0.915	$0.915	$0.915
4										
5	Commodity Related Charges per GJ									
6										
7	Commodity Cost Recovery	$7.575	$7.575	$7.575	($0.673)	($0.673)	($0.673)	$6.902	$6.902	$6.902
8	Midstream Cost Recovery	$0.614	$0.615	$0.676	$0.000	$0.000	$0.000	$0.614	$0.615	$0.676
9	Subtotal Commodity Related Charges per GJ	$8.189	$8.190	$8.251	($0.673)	($0.673)	($0.673)	$7.516	$7.517	$7.578
10										
11										
12										
13										
14										
15	Charges per GJ for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
16										
17										
18										
19	Riders: 2 (Reserved for future use)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
20	3 ESM	($0.029)	($0.029)	($0.029)	$0.000	$0.000	$0.000	($0.029)	($0.029)	($0.029)
21	6 MCRA	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
22										
23										
24										
25	Total Variable Cost per GJ	$9.075	$9.076	$9.137	($0.673)	($0.673)	($0.673)	$8.402	$8.403	$8.464

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE	EXISTING OCTOBER 1, 2007 RATES			DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES			EFFECTIVE JANUARY 1, 2008 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$10.94	$10.94	$10.94	$0.19	$0.19	$0.19	$11.13	$11.13	$11.13
3										
4	Delivery Charge per gigajoule	$2.736	$2.736	$2.736	$0.047	$0.047	$0.047	$2.783	$2.783	$2.783
5										
6	Rider 3 ESM	($0.108)	($0.108)	($0.108)	($0.022)	($0.022)	($0.022)	($0.130)	($0.130)	($0.130)
7	Rider 5 RSAM	$0.145	$0.145	$0.145	($0.050)	($0.050)	($0.050)	$0.095	$0.095	$0.095
8	Subtotal Delivery Margin Related Charges per gigajoule	$2.773	$2.773	$2.773	($0.025)	($0.025)	($0.025)	$2.748	$2.748	$2.748
9										
10										
11	Commodity Related Charges									
12	Commodity Cost Recovery Charge per gigajoule	$6.926	$6.926	$6.926	$0.000	$0.000	$0.000	$6.926	$6.926	$6.926
13	Midstream Cost Recovery Charge per gigajoule	$0.859	$0.850	$0.912	$0.350	$0.336	$0.353	$1.209	$1.186	$1.265
14	Propane Surcharge (Revelstoke only)		$6.963			$2.582			$9.545	
15	Rider 8 Unbundling Recovery	$0.000	$0.000	$0.000	$0.118	$0.118	$0.118	$0.118	$0.118	$0.118
16	Rider 9 Stable Rate - Residential	$0.001	$0.001	$0.001	($0.001)	($0.001)	($0.001)	$0.000	$0.000	$0.000
17	Subtotal Commodity Related Charges per gigajoule	$7.786	$7.777	$7.839	$0.467	$0.453	$0.470	$8.253	$8.230	$8.309
18										
19										
20	Total Variable Cost per gigajoule	$10.559	$10.550	$10.612	$0.442	$0.428	$0.445	$11.001	$10.978	$11.057
21										
22										
23	Revelstoke Variable Cost per gigajoule									
24	(Includes Rider 1, Excludes Rider 9)		$17.512			$2.893			$20.405	

Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE Particulars	EXISTING OCTOBER 1, 2007 RATES Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	EFFECTIVE JANUARY 1, 2008 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$22.96	$22.96	$22.96	$0.39	$0.39	$0.39	$23.35	$23.35	$23.35
3										
4	Delivery Charge per gigajoule	$2.291	$2.291	$2.291	$0.039	$0.039	$0.039	$2.330	$2.330	$2.330
5										
6	Rider 3 ESM	($0.084)	($0.084)	($0.084)	($0.016)	($0.016)	($0.016)	($0.100)	($0.100)	($0.100)
7	Rider 5 RSAM	$0.145	$0.145	$0.145	($0.050)	($0.050)	($0.050)	$0.095	$0.095	$0.095
8	Subtotal Delivery Margin Related Charges per gigajoule	$2.352	$2.352	$2.352	($0.027)	($0.027)	($0.027)	$2.325	$2.325	$2.325
9										
10										
11	Commodity Related Charges									
12	Commodity Cost Recovery Charge per gigajoule	$6.928	$6.928	$6.928	$0.000	$0.000	$0.000	$6.928	$6.928	$6.928
13	Midstream Cost Recovery Charge per gigajoule	$0.865	$0.856	$0.918	$0.438	$0.423	$0.441	$1.303	$1.279	$1.359
14	Propane Surcharge (Revelstoke only)		$5.864			$2.495			$8.359	
15	Rider 8 Unbundling Recovery	$0.053	$0.053	$0.053	($0.006)	($0.006)	($0.006)	$0.047	$0.047	$0.047
16	Subtotal Commodity Related Charges per gigajoule	$7.846	$7.837	$7.899	$0.432	$0.417	$0.435	$8.278	$8.254	$8.334
17										
18										
19	Total Variable Cost per gigajoule	$10.198	$10.189	$10.251	$0.405	$0.390	$0.408	$10.603	$10.579	$10.659
20										
21										
22	Revelstoke Variable Cost per gigajoule									
23	(Includes Rider 1)		$16.000			$2.891			$18.891	

	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE	**EXISTING OCTOBER 1, 2007 RATES**			**DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES**			**EFFECTIVE JANUARY 1, 2008 RATES**		
Line No.	Particulars	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$122.48	$122.48	$122.48	$2.10	$2.10	$2.10	$124.58	$124.58	$124.58
3										
4	Delivery Charge per gigajoule	$1.974	$1.974	$1.974	$0.034	$0.034	$0.034	$2.008	$2.008	$2.008
5										
6	Rider 3 ESM	($0.065)	($0.065)	($0.065)	($0.012)	($0.012)	($0.012)	($0.077)	($0.077)	($0.077)
7	Rider 5 RSAM	$0.145	$0.145	$0.145	($0.050)	($0.050)	($0.050)	$0.095	$0.095	$0.095
8	Subtotal Delivery Margin Related Charges per gigajoule	$2.054	$2.054	$2.054	($0.028)	($0.028)	($0.028)	$2.026	$2.026	$2.026
9										
10										
11	Commodity Related Charges									
12	Commodity Cost Recovery Charge per gigajoule	$6.916	$6.916	$6.916	$0.000	$0.000	$0.000	$6.916	$6.916	$6.916
13	Midstream Cost Recovery Charge per gigajoule	$0.761	$0.756	$0.817	$0.354	$0.340	$0.358	$1.115	$1.096	$1.175
14	Propane Surcharge (Revelstoke only)		$5.976			$2.578			$8.554	
15	Rider 8 Unbundling Recovery	$0.053	$0.053	$0.053	($0.006)	($0.006)	($0.006)	$0.047	$0.047	$0.047
16	Subtotal Commodity Related Charges per gigajoule	$7.730	$7.725	$7.786	$0.348	$0.334	$0.352	$8.078	$8.059	$8.138
17										
18										
19	Total Variable Cost per gigajoule	$9.784	$9.779	$9.840	$0.320	$0.306	$0.324	$10.104	$10.085	$10.164
20										
21										
22	Revelstoke Variable Cost per gigajoule									
23	(Includes Rider 1)		$15.702			$2.890			$18.592	

	RATE SCHEDULE 4: SEASONAL SERVICE	**EXISTING OCTOBER 1, 2007 RATES**			**DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES**			**EFFECTIVE JANUARY 1, 2008 RATES**		
Line No.	Particulars	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$406.00	$406.00	$406.00	$7.00	$7.00	$7.00	$413.00	$413.00	$413.00
3										
4	Delivery Charge per gigajoule									
5	(a) Off-Peak Period	$0.705	$0.705	$0.705	$0.012	$0.012	$0.012	$0.717	$0.717	$0.717
6	(b) Extension Period	$1.422	$1.422	$1.422	$0.024	$0.024	$0.024	$1.446	$1.446	$1.446
7										
8	Rider 3 ESM	($0.037)	($0.037)	($0.037)	($0.006)	($0.006)	($0.006)	($0.043)	($0.043)	($0.043)
9										
10										
11	Commodity Related Charges									
12	Commodity Cost Recovery Charge per gigajoule									
13	(a) Off-Peak Period	$6.902	$6.902	$6.902	$0.000	$0.000	$0.000	$6.902	$6.902	$6.902
14	(b) Extension Period	$6.902	$6.902	$6.902	$0.000	$0.000	$0.000	$6.902	$6.902	$6.902
15										
16	Midstream Cost Recovery Charge per gigajoule									
17	(a) Off-Peak Period	$0.614	$0.615	$0.676	$0.209	$0.197	$0.211	$0.823	$0.812	$0.887
18	(b) Extension Period	$0.614	$0.615	$0.676	$0.209	$0.197	$0.211	$0.823	$0.812	$0.887
19										
20										
21	Subtotal Off -Peak Commodity Related Charges per GJ									
22	(a) Off-Peak Period	$7.516	$7.517	$7.578	$0.209	$0.197	$0.211	$7.725	$7.714	$7.789
23	(b) Extension Period	$7.516	$7.517	$7.578	$0.209	$0.197	$0.211	$7.725	$7.714	$7.789
24										
25										
26										
27	Unauthorized Gas Charge per gigajoule	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
28	during peak period									
29										
30										
31	Total Variable Cost per gigajoule between									
32	(a) Off-Peak Period	$8.184	$8.185	$8.246	$0.215	$0.203	$0.217	$8.399	$8.388	$8.463
33	(b) Extension Period	$8.901	$8.902	$8.963	$0.227	$0.215	$0.229	$9.128	$9.117	$9.192

Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE	EXISTING OCTOBER 1, 2007 RATES			DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES			EFFECTIVE JANUARY 1, 2008 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$542.00	$542.00	$542.00	$9.00	$9.00	$9.00	$551.00	$551.00	$551.00
3										
4	Demand Charge per gigajoule	$13.543	$13.543	$13.543	$0.233	$0.233	$0.233	$13.776	$13.776	$13.776
5										
6	Delivery Charge per gigajoule	$0.548	$0.548	$0.548	$0.009	$0.009	$0.009	$0.557	$0.557	$0.557
7										
8	Rider 3 ESM	($0.047)	($0.047)	($0.047)	($0.008)	($0.008)	($0.008)	($0.055)	($0.055)	($0.055)
9										
10										
11										
12	Commodity Related Charges									
13	Commodity Cost Recovery Charge per gigajoule	$6.902	$6.902	$6.902	$0.000	$0.000	$0.000	$6.902	$6.902	$6.902
14	Midstream Cost Recovery Charge per gigajoule	$0.614	$0.615	$0.676	$0.209	$0.197	$0.211	$0.823	$0.812	$0.887
15	Subtotal Commodity Related Charges per gigajoule	$7.516	$7.517	$7.578	$0.209	$0.197	$0.211	$7.725	$7.714	$7.789
16										
17										
18										
19	Total Variable Cost per gigajoule	$8.017	$8.018	$8.079	$0.210	$0.198	$0.212	$8.227	$8.216	$8.291

Line No.	RATE SCHEDULE 6: NGV - STATIONS Particulars	EXISTING OCTOBER 1, 2007 RATES Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	EFFECTIVE JANUARY 1, 2008 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$57.00	$57.00	$57.00	$1.00	$1.00	$1.00	$58.00	$58.00	$58.00
3										
4	Delivery Charge per gigajoule	$3.140	$3.140	$3.140	$0.054	$0.054	$0.054	$3.194	$3.194	$3.194
5										
6	Rider 3 ESM	($0.090)	($0.090)	($0.090)	($0.020)	($0.020)	($0.020)	($0.110)	($0.110)	($0.110)
7										
8										
9										
10	Commodity Related Charges									
11	Commodity Cost Recovery Charge per gigajoule	$6.883	$6.883	$6.883	$0.000	$0.000	$0.000	$6.883	$6.883	$6.883
12	Midstream Cost Recovery Charge per gigajoule	$0.420	$0.424	$0.424	$0.032	$0.007	$0.007	$0.452	$0.431	$0.431
13	Subtotal Commodity Related Charges per gigajoule	$7.303	$7.307	$7.307	$0.032	$0.007	$0.007	$7.335	$7.314	$7.314
14										
15										
16										
17										
18	Total Variable Cost per gigajoule	$10.353	$10.357	$10.357	$0.066	$0.041	$0.041	$10.419	$10.398	$10.398

RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	EXISTING OCTOBER 1, 2007 RATES	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES	EFFECTIVE JANUARY 1, 2008 RATES
	(1)	(2)	(3)	(4)
1	**LOWER MAINLAND SERVICE AREA**			
2				
3	Delivery Margin Related Charges			
4	Basic Charge per Month	$80.00	$1.00	$81.00
5				
6	Minimum Charges	$125.00	$0.00	$125.00
7				
8	Delivery Charge per gigajoule	$3.103	$0.053	$3.156
9				
10	Rider 3 ESM	($0.090)	($0.020)	($0.110)
11				
12				
13				
14	Commodity Related Charges			
15	Commodity Cost Recovery Charge per gigajoule	$6.883	$0.000	$6.883
16	Midstream Cost Recovery Charge per gigajoule	$0.420	$0.032	$0.452
17	Subtotal Commodity Related Charges per gigajoule	$7.303	$0.032	$7.335
18				
19	Compression Charge per gigajoule	$5.28	$0.000	$5.28
20				
21				
22				
23				
24	Total Variable Cost per gigajoule	$15.596	$0.065	$15.661

Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES	EXISTING OCTOBER 1, 2007 RATES			DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES			EFFECTIVE JANUARY 1, 2008 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$813.00	$813.00	$813.00	$14.00	$14.00	$14.00	$827.00	$827.00	$827.00
3										
4	Delivery Charge per gigajoule	$0.915	$0.915	$0.915	$0.016	$0.016	$0.016	$0.931	$0.931	$0.931
5										
6	Rider 3 ESM	($0.029)	($0.029)	($0.029)	($0.005)	($0.005)	($0.005)	($0.034)	($0.034)	($0.034)
7										
8										
9	Commodity Related Charges									
10	Commodity Cost Recovery Charge per gigajoule	$6.902	$6.902	$6.902	$0.000	$0.000	$0.000	$6.902	$6.902	$6.902
11	Midstream Cost Recovery Charge per gigajoule	$0.614	$0.615	$0.676	$0.209	$0.197	$0.211	$0.823	$0.812	$0.887
12	Subtotal Commodity Related Charges per gigajoule	$7.516	$7.517	$7.578	$0.209	$0.197	$0.211	$7.725	$7.714	$7.789
13										
14										
15										
16	Charges per gigajoule for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17										
18										
19										
20										
21										
22	Total Variable Cost per gigajoule	$8.402	$8.403	$8.464	$0.220	$0.208	$0.222	$8.622	$8.611	$8.686

Line No.	RATE SCHEDULE 22: LARGE INDUSTRIAL T-SERVICE	EXISTING OCTOBER 1, 2007 RATES			DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES			EFFECTIVE JANUARY 1, 2008 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$3,386.00	$3,386.00	$3,386.00	$58.00	$58.00	$58.00	$3,444.00	$3,444.00	$3,444.00
2										
3	Delivery Charge per gigajoule (Interr. MTQ)	$0.677	$0.677	$0.677	$0.012	$0.012	$0.012	$0.689	$0.689	$0.689
4										
5	Rider 3 ESM	($0.021)	($0.021)	($0.021)	($0.003)	($0.003)	($0.003)	($0.024)	($0.024)	($0.024)
6										
7										
8		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
9	Charges per gigajoule for UOR Gas									
10										
11										
12	Demand Surcharge per gigajoule	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00	$17.00	$17.00	$17.00
13										
14										
15	Balancing Service per gigajoule									
16	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.30	n/a	$0.00	$0.00	n/a	$0.30	$0.30	n/a
17	(b) between and including Nov. 1 and Mar. 31	$1.10	$1.10	n/a	$0.00	$0.00	n/a	$1.10	$1.10	n/a
18										
19								Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
20	Charges per gigajoule for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.								
21										
22										
23										
24	Administration Charge per Month	$72.00	$72.00	$72.00	$1.00	$1.00	$1.00	$73.00	$73.00	$73.00
25										
26										
27										
28										
29	Total Variable Cost per gigajoule	$0.656	$0.656	$0.656	$0.009	$0.009	$0.009	$0.665	$0.665	$0.665

RATE SCHEDULE 22A:
LARGE INDUSTRIAL T-SERVICE

Line No.	Particulars	EXISTING OCTOBER 1, 2007 RATES	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES	EFFECTIVE JANUARY 1, 2008 RATES
	(1)	(2)	(3)	(4)
1	**INLAND SERVICE AREA**			
2				
3	Basic Charge per Month	$4,446.00	$76.00	$4,522.00
4				
5	Delivery Charge per gigajoule - Firm			
6	(a) Firm DTQ	$10.873	$0.187	$11.060
7	(b) Firm MTQ	$0.076	$0.001	$0.077
8				
9	Delivery Charge per gigajoule - Interr MTQ	$0.868	$0.015	$0.883
10				
11	Rider 3 ESM	($0.016)	($0.004)	($0.020)
12				
13				
14	Charges per gigajoule for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
15				
16				
17	Demand Surchage per gigajoule	$17.00	$0.00	$17.00
18				
19	Balancing Service per gigajoule			
20	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.00	$0.30
21	(b) between and including Nov. 1 and Mar. 31	$1.10	$0.00	$1.10
22				
23				
24	Charges per gigajoule for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
25				
26				
27	Replacement Gas	Sumas Daily Price		Sumas Daily Price
28		plus 20 Percent		plus 20 Percent
29				
30	Administration Charge per Month	$72.00	$1.00	$73.00
31				
32	Total Variable Cost per gigajoule			
33	(a) Firm MTQ	$0.060	($0.003)	$0.057
34	(b) Interruptible MTQ	$0.852	$0.011	$0.863

Line No.	RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE Particulars	EXISTING OCTOBER 1, 2007 RATES Columbia Except Elkview	 Elkview Coal	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES Columbia Except Elkview	 Elkview Coal	EFFECTIVE JANUARY 1, 2008 RATES Columbia Except Elkview	 Elkview Coal
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**COLUMBIA SERVICE AREA**						
2							
3	Basic Charge per Month	$4,193.00	$4,193.00	$72.00	$72.00	$4,265.00	$4,265.00
4							
5	Delivery Charge per gigajoule - Firm						
6	(a) Firm DTQ	$6.928	$1.573	$0.119	$0.027	$7.047	$1.600
7	(b) Firm MTQ	$0.074	$0.074	$0.001	$0.001	$0.075	$0.075
8							
9	Delivery Charge per gigajoule - Interr MTQ						
10	(a) between and including Apr. 1 and Oct. 31	$0.690	$0.172	$0.012	$0.003	$0.702	$0.175
11	(b) between and including Nov. 1 and Mar.31	$0.995	$0.247	$0.017	$0.004	$1.012	$0.251
12							
13	Rider 3 ESM	($0.018)	($0.006)	$0.002	$0.000	($0.016)	($0.006)
14							
15							
16		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
17	Charges per gigajoule for UOR Gas						
18							
19							
20	Demand Surchage per gigajoule	$17.00	$17.00	$0.00	$0.00	$17.00	$17.00
21							
22		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
23	Charges per gigajoule for Backstopping Gas						
24							
25							
26	Administration Charge per Month	$72.00	$72.00	$1.00	$1.00	$73.00	$73.00
27							
28							
29	Total Variable Cost per gigajoule						
30	(a) Firm MTQ	$0.056	$0.068	$0.003	$0.001	$0.059	$0.069
31	(b) Interruptible MTQ - Summer	$0.672	$0.166	$0.014	$0.003	$0.686	$0.169
32	- Winter	$0.977	$0.241	$0.019	$0.004	$0.996	$0.245

Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE	EXISTING OCTOBER 1, 2007 RATES			DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES			EFFECTIVE JANUARY 1, 2008 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$122.48	$122.48	$122.48	$2.10	$2.10	$2.10	$124.58	$124.58	$124.58
2										
3	Delivery Charge per gigajoule	$1.974	$1.97	$1.97	$0.034	$0.034	$0.034	$2.008	$2.008	$2.008
4										
5										
6	Administration Charge per Month	$72.00	$72.00	$72.00	$1.00	$1.00	$1.00	$73.00	$73.00	$73.00
7										
8	Sales									
9	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per gigajoule for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	Rider 3 ESM ESM	($0.065)	($0.065)	($0.065)	($0.012)	($0.012)	($0.012)	($0.077)	($0.077)	($0.077)
15	Rider 5 RSAM	$0.145	$0.145	$0.145	($0.050)	($0.050)	($0.050)	$0.095	$0.095	$0.095
16										
17										
18										
19	Total Variable Cost per gigajoule	$2.054	$2.054	$2.054	($0.028)	($0.028)	($0.028)	$2.026	$2.026	$2.026

Line No.	RATE SCHEDULE 25 GENERAL FIRM T-SERVICE Particulars	EXISTING OCTOBER 1, 2007 RATES Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	EFFECTIVE JANUARY 1, 2008 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$542.00	$542.00	$542.00	$9.00	$9.00	$9.00	$551.00	$551.00	$551.00
2										
3	Demand Charge per gigajoule	$13.543	$13.543	$13.543	$0.233	$0.233	$0.233	$13.776	$13.776	$13.776
4										
5	Delivery Charge per gigajoule (Interr. MTQ)	$0.548	$0.548	$0.548	$0.009	$0.009	$0.009	$0.557	$0.557	$0.557
6										
7	Administration Charge per Month	$72.00	$72.00	$72.00	$1.00	$1.00	$1.00	$73.00	$73.00	$73.00
8										
9										
10	Sales									
11	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per gigajoule for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per gigajoule for UOR Gas									
15										
16										
17	Rider 3 ESM	($0.047)	($0.047)	($0.047)	($0.008)	($0.008)	($0.008)	($0.055)	($0.055)	($0.055)
18										
19										
20										
21	Total Variable Cost per gigajoule	$0.501	$0.501	$0.501	$0.001	$0.001	$0.001	$0.502	$0.502	$0.502

Line No.	**RATE SCHEDULE 27: INTERRUPTIBLE T-SERVICE** Particulars	**EXISTING OCTOBER 1, 2007 RATES** Lower Mainland	Inland	Columbia	**DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES** Lower Mainland	Inland	Columbia	**EFFECTIVE JANUARY 1, 2008 RATES** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$813.00	$813.00	$813.00	$14.00	$14.00	$14.00	$827.00	$827.00	$827.00
2										
3										
4	Delivery Charge per gigajoule (Interr. MTQ)	$0.915	$0.915	$0.915	$0.016	$0.016	$0.016	$0.931	$0.931	$0.931
5										
6	Administration Charge per Month	$72.00	$72.00	$72.00	$1.00	$1.00	$1.00	$73.00	$73.00	$73.00
7										
8										
9	Sales									
10	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
11	(b) Charge per gigajoule for Backstopping Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
17	Rider 3 ESM	($0.029)	($0.029)	($0.029)	($0.005)	($0.005)	($0.005)	($0.034)	($0.034)	($0.034)
18										
19										
20	Total Variable Cost per gigajoule	$0.886	$0.886	$0.886	$0.011	$0.011	$0.011	$0.897	$0.897	$0.897

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE	EXISTING JANUARY 1, 2008 RATES			RATE RIDERS CHANGES			EFFECTIVE FEBRUARY 1, 2008 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$11.13	$11.13	$11.13	$0.00	$0.00	$0.00	$11.13	$11.13	$11.13
3										
4	Delivery Charge per gigajoule	$2.783	$2.783	$2.783	$0.000	$0.000	$0.000	$2.783	$2.783	$2.783
5										
6	Rider 3 ESM	($0.130)	($0.130)	($0.130)	$0.003	$0.003	$0.003	($0.127)	($0.127)	($0.127)
7	Rider 5 RSAM	$0.095	$0.095	$0.095	($0.001)	($0.001)	($0.001)	$0.094	$0.094	$0.094
8	Subtotal Delivery Margin Related Charges per gigajoule	$2.748	$2.748	$2.748	$0.002	$0.002	$0.002	$2.750	$2.750	$2.750
9										
10										
11	Commodity Related Charges									
12	Commodity Cost Recovery Charge per gigajoule	$6.926	$6.926	$6.926	$0.000	$0.000	$0.000	$6.926	$6.926	$6.926
13	Midstream Cost Recovery Charge per gigajoule	$1.209	$1.186	$1.265	$0.000	$0.000	$0.000	$1.209	$1.186	$1.265
14	Propane Surcharge (Revelstoke only)		$9.545			$0.000			$9.545	
15	Rider 8 Unbundling Recovery	$0.118	$0.118	$0.118	($0.001)	($0.001)	($0.001)	$0.117	$0.117	$0.117
16	Rider 9 Stable Rate - Residential	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
17	Subtotal Commodity Related Charges per gigajoule	$8.253	$8.230	$8.309	($0.001)	($0.001)	($0.001)	$8.252	$8.229	$8.308
18										
19										
20	Total Variable Cost per gigajoule	$11.001	$10.978	$11.057	$0.001	$0.001	$0.001	$11.002	$10.979	$11.058
21										
22										
23	Revelstoke Variable Cost per gigajoule									
24	(Includes Rider 1, Excludes Rider 9)		$20.405			$0.002			$20.407	

Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE Particulars	EXISTING JANUARY 1, 2008 RATES Lower Mainland	 Inland	 Columbia	RATE RIDERS CHANGES Lower Mainland	 Inland	 Columbia	EFFECTIVE FEBRUARY 1, 2008 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$23.35	$23.35	$23.35	$0.00	$0.00	$0.00	$23.35	$23.35	$23.35
3										
4	Delivery Charge per gigajoule	$2.330	$2.330	$2.330	$0.000	$0.000	$0.000	$2.330	$2.330	$2.330
5										
6	Rider 3 ESM	($0.100)	($0.100)	($0.100)	$0.002	$0.002	$0.002	($0.098)	($0.098)	($0.098)
7	Rider 5 RSAM	$0.095	$0.095	$0.095	($0.001)	($0.001)	($0.001)	$0.094	$0.094	$0.094
8	Subtotal Delivery Margin Related Charges per gigajoule	$2.325	$2.325	$2.325	$0.001	$0.001	$0.001	$2.326	$2.326	$2.326
9										
10										
11	Commodity Related Charges									
12	Commodity Cost Recovery Charge per gigajoule	$6.928	$6.928	$6.928	$0.000	$0.000	$0.000	$6.928	$6.928	$6.928
13	Midstream Cost Recovery Charge per gigajoule	$1.303	$1.279	$1.359	$0.000	$0.000	$0.000	$1.303	$1.279	$1.359
14	Propane Surcharge (Revelstoke only)		$8.359			$0.000			$8.359	
15	Rider 8 Unbundling Recovery	$0.047	$0.047	$0.047	$0.000	$0.000	$0.000	$0.047	$0.047	$0.047
16	Subtotal Commodity Related Charges per gigajoule	$8.278	$8.254	$8.334	$0.000	$0.000	$0.000	$8.278	$8.254	$8.334
17										
18										
19	Total Variable Cost per gigajoule	$10.603	$10.579	$10.659	$0.001	$0.001	$0.001	$10.604	$10.580	$10.660
20										
21										
22	Revelstoke Variable Cost per gigajoule									
23	(Includes Rider 1)		$18.891			$0.001			$18.892	

Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE	EXISTING JANUARY 1, 2008 RATES			RATE RIDERS CHANGES			EFFECTIVE FEBRUARY 1, 2008 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$124.58	$124.58	$124.58	$0.00	$0.00	$0.00	$124.58	$124.58	$124.58
3										
4	Delivery Charge per gigajoule	$2.008	$2.008	$2.008	$0.000	$0.000	$0.000	$2.008	$2.008	$2.008
5										
6	Rider 3 ESM	($0.077)	($0.077)	($0.077)	$0.002	$0.002	$0.002	($0.075)	($0.075)	($0.075)
7	Rider 5 RSAM	$0.095	$0.095	$0.095	($0.001)	($0.001)	($0.001)	$0.094	$0.094	$0.094
8	Subtotal Delivery Margin Related Charges per gigajoule	$2.026	$2.026	$2.026	$0.001	$0.001	$0.001	$2.027	$2.027	$2.027
9										
10										
11	Commodity Related Charges									
12	Commodity Cost Recovery Charge per gigajoule	$6.916	$6.916	$6.916	$0.000	$0.000	$0.000	$6.916	$6.916	$6.916
13	Midstream Cost Recovery Charge per gigajoule	$1.115	$1.096	$1.175	$0.000	$0.000	$0.000	$1.115	$1.096	$1.175
14	Propane Surcharge (Revelstoke only)		$8.554			$0.000			$8.554	
15	Rider 8 Unbundling Recovery	$0.047	$0.047	$0.047	$0.000	$0.000	$0.000	$0.047	$0.047	$0.047
16	Subtotal Commodity Related Charges per gigajoule	$8.078	$8.059	$8.138	$0.000	$0.000	$0.000	$8.078	$8.059	$8.138
17										
18										
19	Total Variable Cost per gigajoule	$10.104	$10.085	$10.164	$0.001	$0.001	$0.001	$10.105	$10.086	$10.165
20										
21										
22	Revelstoke Variable Cost per gigajoule									
23	(Includes Rider 1)		$18.592			$0.001			$18.593	

Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE Particulars	EXISTING JANUARY 1, 2008 RATES Lower Mainland	Inland	Columbia	RATE RIDERS CHANGES Lower Mainland	Inland	Columbia	EFFECTIVE FEBRUARY 1, 2008 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$551.00	$551.00	$551.00	$0.00	$0.00	$0.00	$551.00	$551.00	$551.00
3										
4	Demand Charge per gigajoule	$13.776	$13.776	$13.776	$0.000	$0.000	$0.000	$13.776	$13.776	$13.776
5										
6	Delivery Charge per gigajoule	$0.557	$0.557	$0.557	$0.000	$0.000	$0.000	$0.557	$0.557	$0.557
7										
8	Rider 3 ESM	($0.055)	($0.055)	($0.055)	$0.001	$0.001	$0.001	($0.054)	($0.054)	($0.054)
9										
10										
11										
12	Commodity Related Charges									
13	Commodity Cost Recovery Charge per gigajoule	$6.902	$6.902	$6.902	$0.000	$0.000	$0.000	$6.902	$6.902	$6.902
14	Midstream Cost Recovery Charge per gigajoule	$0.823	$0.812	$0.887	$0.000	$0.000	$0.000	$0.823	$0.812	$0.887
15	Subtotal Commodity Related Charges per gigajoule	$7.725	$7.714	$7.789	$0.000	$0.000	$0.000	$7.725	$7.714	$7.789
16										
17										
18										
19	Total Variable Cost per gigajoule	$8.227	$8.216	$8.291	$0.001	$0.001	$0.001	$8.228	$8.217	$8.292

Line No.	RATE SCHEDULE 6: NGV - STATIONS Particulars	EXISTING JANUARY 1, 2008 RATES Lower Mainland	Inland	Columbia	RATE RIDERS CHANGES Lower Mainland	Inland	Columbia	EFFECTIVE FEBRUARY 1, 2008 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	Basic Charge per Month	$58.00	$58.00	$58.00	$0.00	$0.00	$0.00	$58.00	$58.00	$58.00
3										
4	Delivery Charge per gigajoule	$3.194	$3.194	$3.194	$0.000	$0.000	$0.000	$3.194	$3.194	$3.194
5										
6	Rider 3 ESM	($0.110)	($0.110)	($0.110)	$0.010	$0.010	$0.010	($0.100)	($0.100)	($0.100)
7										
8										
9										
10	Commodity Related Charges									
11	Commodity Cost Recovery Charge per gigajoule	$6.883	$6.883	$6.883	$0.000	$0.000	$0.000	$6.883	$6.883	$6.883
12	Midstream Cost Recovery Charge per gigajoule	$0.452	$0.431	$0.431	$0.000	$0.000	$0.000	$0.452	$0.431	$0.431
13	Subtotal Commodity Related Charges per gigajoule	$7.335	$7.314	$7.314	$0.000	$0.000	$0.000	$7.335	$7.314	$7.314
14										
15										
16										
17										
18	Total Variable Cost per gigajoule	$10.419	$10.398	$10.398	$0.010	$0.010	$0.010	$10.429	$10.408	$10.408

RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	EXISTING JANUARY 1, 2008 RATES	RATE RIDERS CHANGES	EFFECTIVE FEBRUARY 1, 2008 RATES
	(1)	(2)	(3)	(4)
1	**LOWER MAINLAND SERVICE AREA**			
2				
3	Delivery Margin Related Charges			
4	Basic Charge per Month	$81.00	$0.00	$81.00
5				
6	Minimum Charges	$125.00	$0.00	$125.00
7				
8	Delivery Charge per gigajoule	$3.156	$0.000	$3.156
9				
10	Rider 3 ESM	($0.110)	$0.010	($0.100)
11				
12				
13				
14	Commodity Related Charges			
15	Commodity Cost Recovery Charge per gigajoule	$6.883	$0.000	$6.883
16	Midstream Cost Recovery Charge per gigajoule	$0.452	$0.000	$0.452
17	Subtotal Commodity Related Charges per gigajoule	$7.335	$0.000	$7.335
18				
19	Compression Charge per gigajoule	$5.28	$0.000	$5.28
20				
21				
22				
23				
24	Total Variable Cost per gigajoule	$15.661	$0.010	$15.671

Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE Particulars	EXISTING JANUARY 1, 2008 RATES Lower Mainland	Inland	Columbia	RATE RIDERS CHANGES Lower Mainland	Inland	Columbia	EFFECTIVE FEBRUARY 1, 2008 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$124.58	$124.58	$124.58	$0.00	$0.00	$0.00	$124.58	$124.58	$124.58
2										
3	Delivery Charge per gigajoule	$2.008	$2.01	$2.01	$0.000	$0.000	$0.000	$2.008	$2.008	$2.008
4										
5										
6	Administration Charge per Month	$73.00	$73.00	$73.00	$0.00	$0.00	$0.00	$73.00	$73.00	$73.00
7										
8	Sales									
9	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per gigajoule for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	Rider 3 ESM	($0.077)	($0.077)	($0.077)	$0.002	$0.002	$0.002	($0.075)	($0.075)	($0.075)
15	Rider 5 RSAM	$0.095	$0.095	$0.095	($0.001)	($0.001)	($0.001)	$0.094	$0.094	$0.094
16										
17										
18										
19	Total Variable Cost per gigajoule	$2.026	$2.026	$2.026	$0.001	$0.001	$0.001	$2.027	$2.027	$2.027

Line No.	RATE SCHEDULE 25 GENERAL FIRM T-SERVICE Particulars	EXISTING JANUARY 1, 2008 RATES Lower Mainland	 Inland	 Columbia	RATE RIDERS CHANGES Lower Mainland	 Inland	 Columbia	EFFECTIVE FEBRUARY 1, 2008 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Basic Charge per Month	$551.00	$551.00	$551.00	$0.00	$0.00	$0.00	$551.00	$551.00	$551.00
2										
3	Demand Charge per gigajoule	$13.776	$13.776	$13.776	$0.000	$0.000	$0.000	$13.776	$13.776	$13.776
4										
5	Delivery Charge per gigajoule (Interr. MTQ)	$0.557	$0.557	$0.557	$0.000	$0.000	$0.000	$0.557	$0.557	$0.557
6										
7	Administration Charge per Month	$73.00	$73.00	$73.00	$0.00	$0.00	$0.00	$73.00	$73.00	$73.00
8										
9										
10	Sales									
11	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per gigajoule for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per gigajoule for UOR Gas									
15										
16										
17	Rider 3 ESM	($0.055)	($0.055)	($0.055)	$0.001	$0.001	$0.001	($0.054)	($0.054)	($0.054)
18										
19										
20										
21	Total Variable Cost per gigajoule	$0.502	$0.502	$0.502	$0.001	$0.001	$0.001	$0.503	$0.503	$0.503

BCUC ORDER NO. G-38-08 (COMMODITY CHARGE) AND G-116-07 DIRECTIVE 4 (RIDER 4 - LOCHBURN LAND SALE REBATE)

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE Particulars	EXISTING FEBRUARY 1, 2008 RATES Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	EFFECTIVE APRIL 1, 2008 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$11.13**	**$11.13**	**$11.13**	**$0.00**	**$0.00**	**$0.00**	**$11.13**	**$11.13**	**$11.13**
3										
4	Delivery Charge per GJ	$2.783	$2.783	$2.783	$0.000	$0.000	$0.000	$2.783	$2.783	$2.783
5	Rider 3 ESM	($0.127)	($0.127)	($0.127)	$0.000	$0.000	$0.000	($0.127)	($0.127)	($0.127)
6	Rider 4 Lochburn Land Sale Rebate	$0.000	$0.000	$0.000	($0.022)	($0.022)	($0.022)	($0.022)	($0.022)	($0.022)
7	Rider 5 RSAM	$0.094	$0.094	$0.094	$0.000	$0.000	$0.000	$0.094	$0.094	$0.094
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.750**	**$2.750**	**$2.750**	**($0.022)**	**($0.022)**	**($0.022)**	**$2.728**	**$2.728**	**$2.728**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.209	$1.186	$1.265	$0.000	$0.000	$0.000	$1.209	$1.186	$1.265
13	Rider 8 Unbundling Recovery	$0.117	$0.117	$0.117	$0.000	$0.000	$0.000	$0.117	$0.117	$0.117
14	Rider 9 Stable Rate - Residential	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	Subtotal **Midstream Related Charges per GJ**	**$1.326**	**$1.303**	**$1.382**	**$0.000**	**$0.000**	**$0.000**	**$1.326**	**$1.303**	**$1.382**
16										
17	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$6.926**	**$6.926**	**$6.926**	**$1.361**	**$1.361**	**$1.361**	**$8.287**	**$8.287**	**$8.287**
18										
19										
20	Rider 1 Propane Surcharge (Revelstoke only)		$9.545			($1.361)			$8.184	
21										
22										
23	**Cost of Gas Recovery Related Charges for Revelstoke**		**$17.657**			**$0.000**			**$17.657**	
24	per GJ (Includes Rider 1, excludes Riders 8 & 9)									

BCUC ORDER NO. G-38-08 (COMMODITY CHARGE) AND G-116-07 DIRECTIVE 4 (RIDER 4 - LOCHBURN LAND SALE REBATE)

Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE Particulars	EXISTING FEBRUARY 1, 2008 RATES Lower Mainland	Inland	Columbia	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	EFFECTIVE APRIL 1, 2008 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$23.35**	**$23.35**	**$23.35**	**$0.00**	**$0.00**	**$0.00**	**$23.35**	**$23.35**	**$23.35**
3										
4	Delivery Charge per GJ	$2.330	$2.330	$2.330	$0.000	$0.000	$0.000	$2.330	$2.330	$2.330
5	Rider 3 ESM	($0.098)	($0.098)	($0.098)	$0.000	$0.000	$0.000	($0.098)	($0.098)	($0.098)
6	Rider 4 Lochburn Land Sale Rebate	$0.000	$0.000	$0.000	($0.017)	($0.017)	($0.017)	($0.017)	($0.017)	($0.017)
7	Rider 5 RSAM	$0.094	$0.094	$0.094	$0.000	$0.000	$0.000	$0.094	$0.094	$0.094
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.326**	**$2.326**	**$2.326**	**($0.017)**	**($0.017)**	**($0.017)**	**$2.309**	**$2.309**	**$2.309**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.303	$1.279	$1.359	$0.000	$0.000	$0.000	$1.303	$1.279	$1.359
13	Rider 8 Unbundling Recovery	$0.047	$0.047	$0.047	$0.000	$0.000	$0.000	$0.047	$0.047	$0.047
14	Subtotal **Midstream Related Charges per GJ**	**$1.350**	**$1.326**	**$1.406**	**$0.000**	**$0.000**	**$0.000**	**$1.350**	**$1.326**	**$1.406**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$6.928**	**$6.928**	**$6.928**	**$1.359**	**$1.359**	**$1.359**	**$8.287**	**$8.287**	**$8.287**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$8.359			($1.359)			$7.000	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$16.566**			**$0.000**			**$16.566**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

BCUC ORDER NO. G-38-08 (COMMODITY CHARGE) AND G-116-07 DIRECTIVE 4 (RIDER 4 - LOCHBURN LAND SALE REBATE)

Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE	EXISTING FEBRUARY 1, 2008 RATES			DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES			EFFECTIVE APRIL 1, 2008 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$124.58**	**$124.58**	**$124.58**	**$0.00**	**$0.00**	**$0.00**	**$124.58**	**$124.58**	**$124.58**
3										
4	Delivery Charge per GJ	$2.008	$2.008	$2.008	$0.000	$0.000	$0.000	$2.008	$2.008	$2.008
5	Rider 3 ESM	($0.075)	($0.075)	($0.075)	$0.000	$0.000	$0.000	($0.075)	($0.075)	($0.075)
6	Rider 4 Lochburn Land Sale Rebate	$0.000	$0.000	$0.000	($0.013)	($0.013)	($0.013)	($0.013)	($0.013)	($0.013)
7	Rider 5 RSAM	$0.094	$0.094	$0.094	$0.000	$0.000	$0.000	$0.094	$0.094	$0.094
8	Subtotal **Midstream Related Charges per GJ**	**$2.027**	**$2.027**	**$2.027**	**($0.013)**	**($0.013)**	**($0.013)**	**$2.014**	**$2.014**	**$2.014**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.115	$1.096	$1.175	$0.000	$0.000	$0.000	$1.115	$1.096	$1.175
13	Rider 8 Unbundling Recovery	$0.047	$0.047	$0.047	$0.000	$0.000	$0.000	$0.047	$0.047	$0.047
14	Subtotal **Midstream Related Charges per GJ**	**$1.162**	**$1.143**	**$1.222**	**$0.000**	**$0.000**	**$0.000**	**$1.162**	**$1.143**	**$1.222**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$6.916**	**$6.916**	**$6.916**	**$1.371**	**$1.371**	**$1.371**	**$8.287**	**$8.287**	**$8.287**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$8.554			($1.371)			$7.183	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$16.566**			**$0.000**			**$16.566**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

BCUC ORDER NO. G-38-08 (COMMODITY CHARGE) AND G-116-07 DIRECTIVE 4 (RIDER 4 - LOCHBURN LAND SALE REBATE)

Line No.	RATE SCHEDULE 4: SEASONAL SERVICE	EXISTING FEBRUARY 1, 2008 RATES			DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES			EFFECTIVE APRIL 1, 2008 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$413.00	$413.00	$413.00	$0.00	$0.00	$0.00	$413.00	$413.00	$413.00
3										
4	**Delivery Charge per GJ**									
5	(a) Off-Peak Period	$0.717	$0.717	$0.717	$0.000	$0.000	$0.000	$0.717	$0.717	$0.717
6	(b) Extension Period	$1.446	$1.446	$1.446	$0.000	$0.000	$0.000	$1.446	$1.446	$1.446
7										
8	**Rider 3 ESM**	($0.043)	($0.043)	($0.043)	$0.000	$0.000	$0.000	($0.043)	($0.043)	($0.043)
9	**Rider 4 Lochburn Land Sale Rebate**	$0.000	$0.000	$0.000	($0.006)	($0.006)	($0.006)	($0.006)	($0.006)	($0.006)
10										
11	Commodity Related Charges									
12	**Commodity Cost Recovery Charge**									
13	(a) Off-Peak Period	$6.902	$6.902	$6.902	$1.385	$1.385	$1.385	$8.287	$8.287	$8.287
14	(b) Extension Period	$6.902	$6.902	$6.902	$1.385	$1.385	$1.385	$8.287	$8.287	$8.287
15										
16	**Midstream Cost Recovery Charge per GJ**									
17	(a) Off-Peak Period	$0.823	$0.812	$0.887	$0.000	$0.000	$0.000	$0.823	$0.812	$0.887
18	(b) Extension Period	$0.823	$0.812	$0.887	$0.000	$0.000	$0.000	$0.823	$0.812	$0.887
19										
20										
21	Subtotal Off -Peak Commodity Related Charges per GJ									
22	(a) Off-Peak Period	$7.725	$7.714	$7.789	$1.385	$1.385	$1.385	$9.110	$9.099	$9.174
23	(b) Extension Period	$7.725	$7.714	$7.789	$1.385	$1.385	$1.385	$9.110	$9.099	$9.174
24										
25										
26										
27	Unauthorized Gas Charge per gigajoule	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
28	during peak period									
29										
30										
31	Total Variable Cost per gigajoule between									
32	(a) Off-Peak Period	$8.399	$8.388	$8.463	$1.379	$1.379	$1.379	$9.778	$9.767	$9.842
33	(b) Extension Period	$9.128	$9.117	$9.192	$1.379	$1.379	$1.379	$10.507	$10.496	$10.571

BCUC ORDER NO. G-38-08 (COMMODITY CHARGE) AND G-116-07 DIRECTIVE 4 (RIDER 4 - LOCHBURN LAND SALE REBATE)

Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE	EXISTING FEBRUARY 1, 2008 RATES			DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES			EFFECTIVE APRIL 1, 2008 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$551.00	$551.00	$551.00	$0.00	$0.00	$0.00	$551.00	$551.00	$551.00
3										
4	**Demand Charge per gigajoule**	$13.776	$13.776	$13.776	$0.000	$0.000	$0.000	$13.776	$13.776	$13.776
5										
6	**Delivery Charge per GJ**	$0.557	$0.557	$0.557	$0.000	$0.000	$0.000	$0.557	$0.557	$0.557
7										
8	**Rider 3 ESM**	($0.054)	($0.054)	($0.054)	$0.000	$0.000	$0.000	($0.054)	($0.054)	($0.054)
9	**Rider 4 Lochburn Land Sale Rebate**	$0.000	$0.000	$0.000	($0.009)	($0.009)	($0.009)	($0.009)	($0.009)	($0.009)
10										
11										
12	Commodity Related Charges									
13	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$6.902	$6.902	$6.902	$1.385	$1.385	$1.385	$8.287	$8.287	$8.287
14	**Midstream Cost Recovery Charge per GJ**	$0.823	$0.812	$0.887	$0.000	$0.000	$0.000	$0.823	$0.812	$0.887
15	Subtotal Midstream Related Charges per GJ	**$7.725**	**$7.714**	**$7.789**	**$1.385**	**$1.385**	**$1.385**	**$9.110**	**$9.099**	**$9.174**
16										
17										
18										
19	Total Variable Cost per gigajoule	$8.228	$8.217	$8.292	$1.376	$1.376	$1.376	$9.604	$9.593	$9.668

BCUC ORDER NO. G-38-08 (COMMODITY CHARGE) AND G-116-07 DIRECTIVE 4 (RIDER 4 - LOCHBURN LAND SALE REBATE)

	RATE SCHEDULE 6: NGV - STATIONS	EXISTING FEBRUARY 1, 2008 RATES			DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES			EFFECTIVE APRIL 1, 2008 RATES		
Line No.	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$58.00	$58.00	$58.00	$0.00	$0.00	$0.00	$58.00	$58.00	$58.00
3										
4	**Delivery Charge per GJ**	$3.194	$3.194	$3.194	$0.000	$0.000	$0.000	$3.194	$3.194	$3.194
5										
6	**Rider 3 ESM**	($0.100)	($0.100)	($0.100)	$0.000	$0.000	$0.000	($0.100)	($0.100)	($0.100)
7	**Rider 4 Lochburn Land Sale Rebate**	$0.000	$0.000	$0.000	($0.020)	($0.020)	($0.020)	($0.020)	($0.020)	($0.020)
8										
9										
10	Commodity Related Charges									
11	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$6.883	$6.883	$6.883	$1.404	$1.404	$1.404	$8.287	$8.287	$8.287
12	**Midstream Cost Recovery Charge per GJ**	$0.452	$0.431	$0.431	$0.000	$0.000	$0.000	$0.452	$0.431	$0.431
13	Subtotal Midstream Related Charges per GJ	**$7.335**	**$7.314**	**$7.314**	**$1.404**	**$1.404**	**$1.404**	**$8.739**	**$8.718**	**$8.718**
14										
15										
16	Total Variable Cost per gigajoule	$10.429	$10.408	$10.408	$1.384	$1.384	$1.384	$11.813	$11.792	$11.792

BCUC ORDER NO. G-38-08 (COMMODITY CHARGE) AND G-116-07 DIRECTIVE 4 (RIDER 4 - LOCHBURN LAND SALE REBATE)

RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	EXISTING FEBRUARY 1, 2008 RATES	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES	EFFECTIVE APRIL 1, 2008 RATES
	(1)	(2)	(3)	(4)
1	**LOWER MAINLAND SERVICE AREA**			
2				
3	**Delivery Margin Related Charges**			
4	Basic Charge per month	$81.00	$0.00	$81.00
5				
6	Delivery Charge per GJ	$3.156	$0.000	$3.156
7	Rider 3 ESM	($0.100)	$0.000	($0.100)
8	Rider 4 Lochburn Land Sale Rebate	$0.000	($0.020)	($0.020)
9				
10				
11	**Commodity Related Charges**			
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$6.883	$1.404	$8.287
13	Midstream Cost Recovery Charge per GJ	$0.452	$0.000	$0.452
14	Subtotal Midstream Related Charges per GJ	$7.335	$1.404	$8.739
15				
16	Compression Charge per gigajoule	$5.28	$0.000	$5.28
17				
18				
19	**Minimum Charges**	$125.00	$0.00	$125.00
20				
21				
22				
23	Total Variable Cost per gigajoule	$15.671	$1.384	$17.055

BCUC ORDER NO. G-38-08 (COMMODITY CHARGE) AND G-116-07 DIRECTIVE 4 (RIDER 4 - LOCHBURN LAND SALE REBATE)

Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES	EXISTING FEBRUARY 1, 2008 RATES			DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES			EFFECTIVE APRIL 1, 2008 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$827.00	$827.00	$827.00	$0.00	$0.00	$0.00	$827.00	$827.00	$827.00
3										
4	**Delivery Charge per GJ**	$0.931	$0.931	$0.931	$0.000	$0.000	$0.000	$0.931	$0.931	$0.931
5										
6	**Rider 3 ESM**	($0.034)	($0.034)	($0.034)	$0.000	$0.000	$0.000	($0.034)	($0.034)	($0.034)
7	**Rider 4 Lochburn Land Sale Rebate**	$0.000	$0.000	$0.000	($0.006)	($0.006)	($0.006)	($0.006)	($0.006)	($0.006)
8										
9	Commodity Related Charges									
10	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$6.902	$6.902	$6.902	$1.385	$1.385	$1.385	$8.287	$8.287	$8.287
11	**Midstream Cost Recovery Charge per GJ**	$0.823	$0.812	$0.887	$0.000	$0.000	$0.000	$0.823	$0.812	$0.887
12	Subtotal Midstream Related Charges per GJ	**$7.725**	**$7.714**	**$7.789**	**$1.385**	**$1.385**	**$1.385**	**$9.110**	**$9.099**	**$9.174**
13										
14										
15										
16	Charges per gigajoule for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17										
18										
19										
20										
21										
22	Total Variable Cost per gigajoule	$8.622	$8.611	$8.686	$1.379	$1.379	$1.379	$10.001	$9.990	$10.065

BCUC ORDER NO. G-116-07 DIRECTIVE 4 (RIDER 4 - LOCHBURN LAND SALE REBATE)

Line No.	RATE SCHEDULE 22: LARGE INDUSTRIAL T-SERVICE Particulars	EXISTING FEBRUARY 1, 2008 RATES Lower Mainland	Inland	Columbia	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	EFFECTIVE APRIL 1, 2008 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$3,444.00	$3,444.00	$3,444.00	$0.00	$0.00	$0.00	$3,444.00	$3,444.00	$3,444.00
2										
3	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.689	$0.689	$0.689	$0.000	$0.000	$0.000	$0.689	$0.689	$0.689
4										
5	**Rider 3 ESM**	($0.024)	($0.024)	($0.024)	$0.000	$0.000	$0.000	($0.024)	($0.024)	($0.024)
6	**Rider 4 Lochburn Land Sale Rebate**	$0.000	$0.000	$0.000	($0.004)	($0.004)	($0.004)	($0.004)	($0.004)	($0.004)
7										
8		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
9	**Charges per gigajoule for UOR Gas**									
10										
11										
12	**Demand Surcharge per gigajoule**	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00	$17.00	$17.00	$17.00
13										
14										
15	**Balancing Service per gigajoule**									
16	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.30	n/a	$0.00	$0.00	n/a	$0.30	$0.30	n/a
17	(b) between and including Nov. 1 and Mar. 31	$1.10	$1.10	n/a	$0.00	$0.00	n/a	$1.10	$1.10	n/a
18										
19										
20	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
21										
22										
23										
24	**Administration Charge per Month**	$73.00	$73.00	$73.00	$0.00	$0.00	$0.00	$73.00	$73.00	$73.00
25										
26										
27										
28										
29	Total Variable Cost per gigajoule	$0.665	$0.665	$0.665	($0.004)	($0.004)	($0.004)	$0.661	$0.661	$0.661

BCUC ORDER NO. G-116-07 DIRECTIVE 4 (RIDER 4 - LOCHBURN LAND SALE REBATE)

Line No.	RATE SCHEDULE 22A: LARGE INDUSTRIAL T-SERVICE Particulars	EXISTING FEBRUARY 1, 2008 RATES	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES	EFFECTIVE APRIL 1, 2008 RATES
	(1)	(2)	(3)	(4)
1	**INLAND SERVICE AREA**			
2				
3	**Basic Charge per Month**	$4,522.00	$0.00	$4,522.00
4				
5	**Delivery Charge per gigajoule - Firm**			
6	(a) Firm DTQ	$11.060	$0.000	$11.060
7	(b) Firm MTQ	$0.077	$0.000	$0.077
8				
9	**Delivery Charge per gigajoule - Interr MTQ**	$0.883	$0.000	$0.883
10				
11	**Rider 3 ESM**	($0.020)	$0.000	($0.020)
12	**Rider 4 Lochburn Land Sale Rebate**	$0.000	($0.003)	($0.003)
13				
14		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
15	**Charges per gigajoule for UOR Gas**			
16				
17				
18	**Demand Surchage per gigajoule**	$17.00	$0.00	$17.00
19				
20	**Balancing Service per gigajoule**			
21	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.00	$0.30
22	(b) between and including Nov. 1 and Mar. 31	$1.10	$0.00	$1.10
23				
24				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
25	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
26				
27				
28	**Replacement Gas**	Sumas Daily Price		Sumas Daily Price
29		plus 20 Percent		plus 20 Percent
30				
31	**Administration Charge per Month**	$73.00	$0.00	$73.00
32				
33	Total Variable Cost per gigajoule			
34	(a) Firm MTQ	$0.057	($0.003)	$0.054
35	(b) Interruptible MTQ	$0.863	($0.003)	$0.860

BCUC ORDER NO. G-116-07 DIRECTIVE 4 (RIDER 4 - LOCHBURN LAND SALE REBATE)

Line No.	RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE Particulars	EXISTING FEBRUARY 1, 2008 RATES Columbia Except Elkview	 Elkview Coal	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES Columbia Except Elkview	 Elkview Coal	EFFECTIVE APRIL 1, 2008 RATES Columbia Except Elkview	 Elkview Coal
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**COLUMBIA SERVICE AREA**						
2							
3	**Basic Charge per Month**	$4,265.00	$4,265.00	$0.00	$0.00	$4,265.00	$4,265.00
4							
5	**Delivery Charge per gigajoule - Firm**						
6	(a) Firm DTQ	$7.047	$1.600	$0.000	$0.000	$7.047	$1.600
7	(b) Firm MTQ	$0.075	$0.075	$0.000	$0.000	$0.075	$0.075
8							
9	**Delivery Charge per gigajoule - Interr MTQ**						
10	(a) between and including Apr. 1 and Oct. 31	$0.702	$0.175	$0.000	$0.000	$0.702	$0.175
11	(b) between and including Nov. 1 and Mar.31	$1.012	$0.251	$0.000	$0.000	$1.012	$0.251
12							
13	**Rider 3 ESM**	($0.016)	($0.006)	$0.000	$0.000	($0.016)	($0.006)
14	**Rider 4 Lochburn Land Sale Rebate**	$0.000	$0.000	($0.003)	($0.002)	($0.003)	($0.002)
15							
16		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
17	**Charges per gigajoule for UOR Gas**						
18							
19							
20	**Demand Surchage per gigajoule**	$17.00	$17.00	$0.00	$0.00	$17.00	$17.00
21							
22		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
23	**Charges per gigajoule for Backstopping Gas**						
24							
25							
26	**Administration Charge per Month**	$73.00	$73.00	$0.00	$0.00	$73.00	$73.00
27							
28							
29	Total Variable Cost per gigajoule						
30	(a) Firm MTQ	$0.059	$0.069	($0.003)	($0.002)	$0.056	$0.067
31	(b) Interruptible MTQ - Summer	$0.686	$0.169	($0.003)	($0.002)	$0.683	$0.167
32	- Winter	$0.996	$0.245	($0.003)	($0.002)	$0.993	$0.243

BCUC ORDER NO. G-116-07 DIRECTIVE 4 (RIDER 4 - LOCHBURN LAND SALE REBATE)

Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE	EXISTING FEBRUARY 1, 2008 RATES			DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES			EFFECTIVE APRIL 1, 2008 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$124.58	$124.58	$124.58	$0.00	$0.00	$0.00	$124.58	$124.58	$124.58
2										
3	**Delivery Charge per gigajoule**	$2.008	$2.01	$2.01	$0.000	$0.000	$0.000	$2.008	$2.008	$2.008
4										
5										
6	**Administration Charge per Month**	$73.00	$73.00	$73.00	$0.00	$0.00	$0.00	$73.00	$73.00	$73.00
7										
8	**Sales**									
9	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per gigajoule for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 3 ESM**	($0.075)	($0.075)	($0.075)	$0.000	$0.000	$0.000	($0.075)	($0.075)	($0.075)
15	**Rider 4 Lochburn Land Sale Rebate**	$0.000	$0.000	$0.000	($0.013)	($0.013)	($0.013)	($0.013)	($0.013)	($0.013)
16	**Rider 5 RSAM**	$0.094	$0.094	$0.094	$0.000	$0.000	$0.000	$0.094	$0.094	$0.094
17										
18										
19										
20	Total Variable Cost per gigajoule	$2.027	$2.027	$2.027	($0.013)	($0.013)	($0.013)	$2.014	$2.014	$2.014

BCUC ORDER NO. G-116-07 DIRECTIVE 4 (RIDER 4 - LOCHBURN LAND SALE REBATE)

Line No.	RATE SCHEDULE 25 GENERAL FIRM T-SERVICE Particulars	EXISTING FEBRUARY 1, 2008 RATES Lower Mainland	Inland	Columbia	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	EFFECTIVE APRIL 1, 2008 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$551.00	$551.00	$551.00	$0.00	$0.00	$0.00	$551.00	$551.00	$551.00
2										
3	**Demand Charge per gigajoule**	$13.776	$13.776	$13.776	$0.000	$0.000	$0.000	$13.776	$13.776	$13.776
4										
5	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.557	$0.557	$0.557	$0.000	$0.000	$0.000	$0.557	$0.557	$0.557
6										
7	**Administration Charge per Month**	$73.00	$73.00	$73.00	$0.00	$0.00	$0.00	$73.00	$73.00	$73.00
8										
9										
10	**Sales**									
11	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per gigajoule for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per gigajoule for UOR Gas									
15										
16										
17	**Rider 3 ESM**	($0.054)	($0.054)	($0.054)	$0.000	$0.000	$0.000	($0.054)	($0.054)	($0.054)
18	**Rider 4 Lochburn Land Sale Rebate**	$0.000	$0.000	$0.000	($0.009)	($0.009)	($0.009)	($0.009)	($0.009)	($0.009)
19										
20										
21										
22	Total Variable Cost per gigajoule	$0.503	$0.503	$0.503	($0.009)	($0.009)	($0.009)	$0.494	$0.494	$0.494

BCUC ORDER NO. G-116-07 DIRECTIVE 4 (RIDER 4 - LOCHBURN LAND SALE REBATE)

Line No.	RATE SCHEDULE 27: INTERRUPTIBLE T-SERVICE Particulars	EXISTING FEBRUARY 1, 2008 RATES Lower Mainland	Inland	Columbia	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	EFFECTIVE APRIL 1, 2008 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$827.00	$827.00	$827.00	$0.00	$0.00	$0.00	$827.00	$827.00	$827.00
2										
3										
4	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.931	$0.931	$0.931	$0.000	$0.000	$0.000	$0.931	$0.931	$0.931
5										
6	**Administration Charge per Month**	$73.00	$73.00	$73.00	$0.00	$0.00	$0.00	$73.00	$73.00	$73.00
7										
8										
9	**Sales**									
10	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
11	(b) Charge per gigajoule for Backstopping Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
17	**Rider 3 ESM**	($0.034)	($0.034)	($0.034)	$0.000	$0.000	$0.000	($0.034)	($0.034)	($0.034)
18	**Rider 4 Lochburn Land Sale Rebate**	$0.000	$0.000	$0.000	($0.006)	($0.006)	($0.006)	($0.006)	($0.006)	($0.006)
19										
20										
21										
22	Total Variable Cost per gigajoule	$0.897	$0.897	$0.897	($0.006)	($0.006)	($0.006)	$0.891	$0.891	$0.891

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
EFFECTIVE JULY 1, 2008 RATES
BCUC ORDER NO. G-94-08 G-92-08

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE — Particulars	EXISTING APRIL 1, 2008 RATES — Lower Mainland	Inland	Columbia	COMMODITY RELATED CHARGES CHANGES — Lower Mainland	Inland	Columbia	EFFECTIVE JULY 1, 2008 RATES — Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$11.13**	**$11.13**	**$11.13**	**$0.00**	**$0.00**	**$0.00**	**$11.13**	**$11.13**	**$11.13**
3										
4	Delivery Charge per GJ	$2.783	$2.783	$2.783	$0.000	$0.000	$0.000	$2.783	$2.783	$2.783
5	Rider 3 ESM	($0.127)	($0.127)	($0.127)	$0.000	$0.000	$0.000	($0.127)	($0.127)	($0.127)
6	Rider 4 Lochburn Land Sale Rebate	($0.022)	($0.022)	($0.022)	$0.000	$0.000	$0.000	($0.022)	($0.022)	($0.022)
7	Rider 5 RSAM	$0.094	$0.094	$0.094	$0.000	$0.000	$0.000	$0.094	$0.094	$0.094
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.728**	**$2.728**	**$2.728**	**$0.000**	**$0.000**	**$0.000**	**$2.728**	**$2.728**	**$2.728**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.209	$1.186	$1.265	$0.000	$0.000	$0.000	$1.209	$1.186	$1.265
13	Rider 8 Unbundling Recovery	$0.117	$0.117	$0.117	$0.000	$0.000	$0.000	$0.117	$0.117	$0.117
14	Subtotal **Midstream Related Charges per GJ**	**$1.326**	**$1.303**	**$1.382**	**$0.000**	**$0.000**	**$0.000**	**$1.326**	**$1.303**	**$1.382**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$8.287**	**$8.287**	**$8.287**	**$1.493**	**$1.493**	**$1.493**	**$9.780**	**$9.780**	**$9.780**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$8.184			$2.222			$10.406	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$17.657**			**$3.715**			**$21.372**	
23	per GJ (Includes Rider 1, excludes Riders 8)									

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
EFFECTIVE JULY 1, 2008 RATES
BCUC ORDER NO. G-94-08 G-92-08

Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE Particulars	EXISTING APRIL 1, 2008 RATES Lower Mainland	Inland	Columbia	COMMODITY RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	EFFECTIVE JULY 1, 2008 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$23.35**	**$23.35**	**$23.35**	**$0.00**	**$0.00**	**$0.00**	**$23.35**	**$23.35**	**$23.35**
3										
4	Delivery Charge per GJ	$2.330	$2.330	$2.330	$0.000	$0.000	$0.000	$2.330	$2.330	$2.330
5	Rider 3 ESM	($0.098)	($0.098)	($0.098)	$0.000	$0.000	$0.000	($0.098)	($0.098)	($0.098)
6	Rider 4 Lochburn Land Sale Rebate	($0.017)	($0.017)	($0.017)	$0.000	$0.000	$0.000	($0.017)	($0.017)	($0.017)
7	Rider 5 RSAM	$0.094	$0.094	$0.094	$0.000	$0.000	$0.000	$0.094	$0.094	$0.094
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.309**	**$2.309**	**$2.309**	**$0.000**	**$0.000**	**$0.000**	**$2.309**	**$2.309**	**$2.309**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.303	$1.279	$1.359	$0.000	$0.000	$0.000	$1.303	$1.279	$1.359
13	Rider 8 Unbundling Recovery	$0.047	$0.047	$0.047	$0.000	$0.000	$0.000	$0.047	$0.047	$0.047
14	Subtotal **Midstream Related Charges per GJ**	**$1.350**	**$1.326**	**$1.406**	**$0.000**	**$0.000**	**$0.000**	**$1.350**	**$1.326**	**$1.406**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$8.287**	**$8.287**	**$8.287**	**$1.493**	**$1.493**	**$1.493**	**$9.780**	**$9.780**	**$9.780**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$7.000			$2.222			$9.222	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$16.566**			**$3.715**			**$20.281**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
EFFECTIVE JULY 1, 2008 RATES
BCUC ORDER NO. G-94-08 G-92-08

Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE	EXISTING APRIL 1, 2008 RATES			COMMODITY RELATED CHARGES CHANGES			EFFECTIVE JULY 1, 2008 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$124.58**	**$124.58**	**$124.58**	**$0.00**	**$0.00**	**$0.00**	**$124.58**	**$124.58**	**$124.58**
3										
4	Delivery Charge per GJ	$2.008	$2.008	$2.008	$0.000	$0.000	$0.000	$2.008	$2.008	$2.008
5	Rider 3 ESM	($0.075)	($0.075)	($0.075)	$0.000	$0.000	$0.000	($0.075)	($0.075)	($0.075)
6	Rider 4 Lochburn Land Sale Rebate	($0.013)	($0.013)	($0.013)	$0.000	$0.000	$0.000	($0.013)	($0.013)	($0.013)
7	Rider 5 RSAM	$0.094	$0.094	$0.094	$0.000	$0.000	$0.000	$0.094	$0.094	$0.094
8	Subtotal **Midstream Related Charges per GJ**	**$2.014**	**$2.014**	**$2.014**	**$0.000**	**$0.000**	**$0.000**	**$2.014**	**$2.014**	**$2.014**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.115	$1.096	$1.175	$0.000	$0.000	$0.000	$1.115	$1.096	$1.175
13	Rider 8 Unbundling Recovery	$0.047	$0.047	$0.047	$0.000	$0.000	$0.000	$0.047	$0.047	$0.047
14	Subtotal **Midstream Related Charges per GJ**	**$1.162**	**$1.143**	**$1.222**	**$0.000**	**$0.000**	**$0.000**	**$1.162**	**$1.143**	**$1.222**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$8.287**	**$8.287**	**$8.287**	**$1.493**	**$1.493**	**$1.493**	**$9.780**	**$9.780**	**$9.780**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$7.183			$2.222			$9.405	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$16.566**			**$3.715**			**$20.281**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

Line No.	**RATE SCHEDULE 4: SEASONAL SERVICE** Particulars	**EXISTING APRIL 1, 2008 RATES** Lower Mainland	Inland	Columbia	**COMMODITY RELATED CHARGES CHANGES** Lower Mainland	Inland	Columbia	**EFFECTIVE JULY 1, 2008 RATES** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$413.00	$413.00	$413.00	$0.00	$0.00	$0.00	$413.00	$413.00	$413.00
3										
4	**Delivery Charge per GJ**									
5	(a) Off-Peak Period	$0.717	$0.717	$0.717	$0.000	$0.000	$0.000	$0.717	$0.717	$0.717
6	(b) Extension Period	$1.446	$1.446	$1.446	$0.000	$0.000	$0.000	$1.446	$1.446	$1.446
7										
8	**Rider 3 ESM**	($0.043)	($0.043)	($0.043)	$0.000	$0.000	$0.000	($0.043)	($0.043)	($0.043)
9	**Rider 4 Lochburn Land Sale Rebate**	($0.006)	($0.006)	($0.006)	$0.000	$0.000	$0.000	($0.006)	($0.006)	($0.006)
10										
11	Commodity Related Charges									
12	**Commodity Cost Recovery Charge**									
13	(a) Off-Peak Period	$8.287	$8.287	$8.287	$1.493	$1.493	$1.493	$9.780	$9.780	$9.780
14	(b) Extension Period	$8.287	$8.287	$8.287	$1.493	$1.493	$1.493	$9.780	$9.780	$9.780
15										
16	**Midstream Cost Recovery Charge per GJ**									
17	(a) Off-Peak Period	$0.823	$0.812	$0.887	$0.000	$0.000	$0.000	$0.823	$0.812	$0.887
18	(b) Extension Period	$0.823	$0.812	$0.887	$0.000	$0.000	$0.000	$0.823	$0.812	$0.887
19										
20										
21	Subtotal Off -Peak Commodity Related Charges per GJ									
22	(a) Off-Peak Period	$9.110	$9.099	$9.174	$1.493	$1.493	$1.493	$10.603	$10.592	$10.667
23	(b) Extension Period	$9.110	$9.099	$9.174	$1.493	$1.493	$1.493	$10.603	$10.592	$10.667
24										
25										
26										
27	Unauthorized Gas Charge per gigajoule	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
28	during peak period									
29										
30										
31	Total Variable Cost per gigajoule between									
32	(a) Off-Peak Period	$9.778	$9.767	$9.842	$1.493	$1.493	$1.493	$11.271	$11.260	$11.335
33	(b) Extension Period	$10.507	$10.496	$10.571	$1.493	$1.493	$1.493	$12.000	$11.989	$12.064

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
EFFECTIVE JULY 1, 2008 RATES
BCUC ORDER NO. G-94-08

Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE	EXISTING APRIL 1, 2008 RATES			COMMODITY RELATED CHARGES CHANGES			EFFECTIVE JULY 1, 2008 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$551.00	$551.00	$551.00	$0.00	$0.00	$0.00	$551.00	$551.00	$551.00
3										
4	**Demand Charge per gigajoule**	$13.776	$13.776	$13.776	$0.000	$0.000	$0.000	$13.776	$13.776	$13.776
5										
6	**Delivery Charge per GJ**	$0.557	$0.557	$0.557	$0.000	$0.000	$0.000	$0.557	$0.557	$0.557
7										
8	**Rider 3 ESM**	($0.054)	($0.054)	($0.054)	$0.000	$0.000	$0.000	($0.054)	($0.054)	($0.054)
9	**Rider 4 Lochburn Land Sale Rebate**	($0.009)	($0.009)	($0.009)	$0.000	$0.000	$0.000	($0.009)	($0.009)	($0.009)
10										
11										
12	Commodity Related Charges									
13	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$8.287	$8.287	$8.287	$1.493	$1.493	$1.493	$9.780	$9.780	$9.780
14	**Midstream Cost Recovery Charge per GJ**	$0.823	$0.812	$0.887	$0.000	$0.000	$0.000	$0.823	$0.812	$0.887
15	Subtotal Commodity Related Charges per GJ	**$9.110**	**$9.099**	**$9.174**	**$1.493**	**$1.493**	**$1.493**	**$10.603**	**$10.592**	**$10.667**
16										
17										
18										
19	Total Variable Cost per gigajoule	$9.604	$9.593	$9.668	$1.493	$1.493	$1.493	$11.097	$11.086	$11.161

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
EFFECTIVE JULY 1, 2008 RATES
BCUC ORDER NO. G-94-08

Line No.	RATE SCHEDULE 6: NGV - STATIONS Particulars	EXISTING APRIL 1, 2008 RATES Lower Mainland	Inland	Columbia	COMMODITY RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	EFFECTIVE JULY 1, 2008 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$58.00	$58.00	$58.00	$0.00	$0.00	$0.00	$58.00	$58.00	$58.00
3										
4	**Delivery Charge per GJ**	$3.194	$3.194	$3.194	$0.000	$0.000	$0.000	$3.194	$3.194	$3.194
5										
6	**Rider 3 ESM**	($0.100)	($0.100)	($0.100)	$0.000	$0.000	$0.000	($0.100)	($0.100)	($0.100)
7	**Rider 4 Lochburn Land Sale Rebate**	($0.020)	($0.020)	($0.020)	$0.000	$0.000	$0.000	($0.020)	($0.020)	($0.020)
8										
9										
10	Commodity Related Charges									
11	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$8.287	$8.287	$8.287	$1.493	$1.493	$1.493	$9.780	$9.780	$9.780
12	**Midstream Cost Recovery Charge per GJ**	$0.452	$0.431	$0.431	$0.000	$0.000	$0.000	$0.452	$0.431	$0.431
13	Subtotal Commodity Related Charges per GJ	**$8.739**	**$8.718**	**$8.718**	**$1.493**	**$1.493**	**$1.493**	**$10.232**	**$10.211**	**$10.211**
14										
15										
16	Total Variable Cost per gigajoule	$11.813	$11.792	$11.792	$1.493	$1.493	$1.493	$13.306	$13.285	$13.285

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
EFFECTIVE JULY 1, 2008 RATES
BCUC ORDER NO. G-94-08

RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	EXISTING APRIL 1, 2008 RATES	COMMODITY RELATED CHARGES CHANGES	EFFECTIVE JULY 1, 2008 RATES
	(1)	(2)	(3)	(4)
1	**LOWER MAINLAND SERVICE AREA**			
2				
3	**Delivery Margin Related Charges**			
4	Basic Charge per month	$81.00	$0.00	$81.00
5				
6	Delivery Charge per GJ	$3.156	$0.000	$3.156
7	Rider 3 ESM	($0.100)	$0.000	($0.100)
8	Rider 4 Lochburn Land Sale Rebate	($0.020)	$0.000	($0.020)
9				
10				
11	**Commodity Related Charges**			
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$8.287	$1.493	$9.780
13	Midstream Cost Recovery Charge per GJ	$0.452	$0.000	$0.452
14	Subtotal Commodity Related Charges per GJ	$8.739	$1.493	$10.232
15				
16	Compression Charge per gigajoule	$5.28	$0.000	$5.28
17				
18				
19	**Minimum Charges**	$125.00	$0.00	$125.00
20				
21				
22				
23	Total Variable Cost per gigajoule	$17.055	$1.493	$18.548

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
EFFECTIVE JULY 1, 2008 RATES
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Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES	EXISTING APRIL 1, 2008 RATES			COMMODITY RELATED CHARGES CHANGES			EFFECTIVE JULY 1, 2008 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$827.00	$827.00	$827.00	$0.00	$0.00	$0.00	$827.00	$827.00	$827.00
3										
4	**Delivery Charge per GJ**	$0.931	$0.931	$0.931	$0.000	$0.000	$0.000	$0.931	$0.931	$0.931
5										
6	**Rider 3 ESM**	($0.034)	($0.034)	($0.034)	$0.000	$0.000	$0.000	($0.034)	($0.034)	($0.034)
7	**Rider 4 Lochburn Land Sale Rebate**	($0.006)	($0.006)	($0.006)	$0.000	$0.000	$0.000	($0.006)	($0.006)	($0.006)
8										
9	Commodity Related Charges									
10	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$8.287	$8.287	$8.287	$1.493	$1.493	$1.493	$9.780	$9.780	$9.780
11	**Midstream Cost Recovery Charge per GJ**	$0.823	$0.812	$0.887	$0.000	$0.000	$0.000	$0.823	$0.812	$0.887
12	Subtotal Commodity Related Charges per GJ	**$9.110**	**$9.099**	**$9.174**	**$1.493**	**$1.493**	**$1.493**	**$10.603**	**$10.592**	**$10.667**
13										
14										
15		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
16	Charges per gigajoule for UOR Gas									
17										
18										
19										
20										
21										
22	Total Variable Cost per gigajoule	$10.001	$9.990	$10.065	$1.493	$1.493	$1.493	$11.494	$11.483	$11.558

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
EFFECTIVE OCTOBER 1, 2008 RATES
BCUC ORDER NO. G-127-08

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE	EXISTING JULY 1, 2008 RATES			COMMODITY RELATED CHARGES CHANGES			EFFECTIVE OCTOBER 1, 2008 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$11.13**	**$11.13**	**$11.13**	**$0.00**	**$0.00**	**$0.00**	**$11.13**	**$11.13**	**$11.13**
3										
4	Delivery Charge per GJ	$2.783	$2.783	$2.783	$0.000	$0.000	$0.000	$2.783	$2.783	$2.783
5	Rider 3 ESM	($0.127)	($0.127)	($0.127)	$0.000	$0.000	$0.000	($0.127)	($0.127)	($0.127)
6	Rider 4 Lochburn Land Sale Rebate	($0.022)	($0.022)	($0.022)	$0.000	$0.000	$0.000	($0.022)	($0.022)	($0.022)
7	Rider 5 RSAM	$0.094	$0.094	$0.094	$0.000	$0.000	$0.000	$0.094	$0.094	$0.094
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.728**	**$2.728**	**$2.728**	**$0.000**	**$0.000**	**$0.000**	**$2.728**	**$2.728**	**$2.728**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.209	$1.186	$1.265	$0.000	$0.000	$0.000	$1.209	$1.186	$1.265
13	Rider 8 Unbundling Recovery	$0.117	$0.117	$0.117	$0.000	$0.000	$0.000	$0.117	$0.117	$0.117
14	Subtotal **Midstream Related Charges per GJ**	**$1.326**	**$1.303**	**$1.382**	**$0.000**	**$0.000**	**$0.000**	**$1.326**	**$1.303**	**$1.382**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$9.780**	**$9.780**	**$9.780**	**($2.244)**	**($2.244)**	**($2.244)**	**$7.536**	**$7.536**	**$7.536**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$10.406			$2.244			$12.650	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$21.372**			**$0.000**			**$21.372**	
23	per GJ (Includes Rider 1, excludes Riders 8)									

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
EFFECTIVE OCTOBER 1, 2008 RATES
BCUC ORDER NO. G-127-08

Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE	EXISTING JULY 1, 2008 RATES			COMMODITY RELATED CHARGES CHANGES			EFFECTIVE OCTOBER 1, 2008 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$23.35**	**$23.35**	**$23.35**	**$0.00**	**$0.00**	**$0.00**	**$23.35**	**$23.35**	**$23.35**
3										
4	Delivery Charge per GJ	$2.330	$2.330	$2.330	$0.000	$0.000	$0.000	$2.330	$2.330	$2.330
5	Rider 3 ESM	($0.098)	($0.098)	($0.098)	$0.000	$0.000	$0.000	($0.098)	($0.098)	($0.098)
6	Rider 4 Lochburn Land Sale Rebate	($0.017)	($0.017)	($0.017)	$0.000	$0.000	$0.000	($0.017)	($0.017)	($0.017)
7	Rider 5 RSAM	$0.094	$0.094	$0.094	$0.000	$0.000	$0.000	$0.094	$0.094	$0.094
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.309**	**$2.309**	**$2.309**	**$0.000**	**$0.000**	**$0.000**	**$2.309**	**$2.309**	**$2.309**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.303	$1.279	$1.359	$0.000	$0.000	$0.000	$1.303	$1.279	$1.359
13	Rider 8 Unbundling Recovery	$0.047	$0.047	$0.047	$0.000	$0.000	$0.000	$0.047	$0.047	$0.047
14	Subtotal **Midstream Related Charges per GJ**	**$1.350**	**$1.326**	**$1.406**	**$0.000**	**$0.000**	**$0.000**	**$1.350**	**$1.326**	**$1.406**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$9.780**	**$9.780**	**$9.780**	**($2.244)**	**($2.244)**	**($2.244)**	**$7.536**	**$7.536**	**$7.536**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$9.222			$2.244			$11.466	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$20.281**			**$0.000**			**$20.281**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

Line No.	**RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE** Particulars	**EXISTING JULY 1, 2008 RATES** Lower Mainland	Inland	Columbia	**COMMODITY RELATED CHARGES CHANGES** Lower Mainland	Inland	Columbia	**EFFECTIVE OCTOBER 1, 2008 RATES** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$124.58**	**$124.58**	**$124.58**	**$0.00**	**$0.00**	**$0.00**	**$124.58**	**$124.58**	**$124.58**
3										
4	Delivery Charge per GJ	$2.008	$2.008	$2.008	$0.000	$0.000	$0.000	$2.008	$2.008	$2.008
5	Rider 3 ESM	($0.075)	($0.075)	($0.075)	$0.000	$0.000	$0.000	($0.075)	($0.075)	($0.075)
6	Rider 4 Lochburn Land Sale Rebate	($0.013)	($0.013)	($0.013)	$0.000	$0.000	$0.000	($0.013)	($0.013)	($0.013)
7	Rider 5 RSAM	$0.094	$0.094	$0.094	$0.000	$0.000	$0.000	$0.094	$0.094	$0.094
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.014**	**$2.014**	**$2.014**	**$0.000**	**$0.000**	**$0.000**	**$2.014**	**$2.014**	**$2.014**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.115	$1.096	$1.175	$0.000	$0.000	$0.000	$1.115	$1.096	$1.175
13	Rider 8 Unbundling Recovery	$0.047	$0.047	$0.047	$0.000	$0.000	$0.000	$0.047	$0.047	$0.047
14	Subtotal **Midstream Related Charges per GJ**	**$1.162**	**$1.143**	**$1.222**	**$0.000**	**$0.000**	**$0.000**	**$1.162**	**$1.143**	**$1.222**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$9.780**	**$9.780**	**$9.780**	**($2.244)**	**($2.244)**	**($2.244)**	**$7.536**	**$7.536**	**$7.536**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$9.405			$2.244			$11.649	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$20.281**			**$0.000**			**$20.281**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

TERASEN GAS INC.
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	RATE SCHEDULE 4: SEASONAL SERVICE	**EXISTING JULY 1, 2008 RATES**			**COMMODITY RELATED CHARGES CHANGES**			**EFFECTIVE OCTOBER 1, 2008 RATES**		
Line No.	Particulars	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$413.00	$413.00	$413.00	$0.00	$0.00	$0.00	$413.00	$413.00	$413.00
3										
4	**Delivery Charge per GJ**									
5	(a) Off-Peak Period	$0.717	$0.717	$0.717	$0.000	$0.000	$0.000	$0.717	$0.717	$0.717
6	(b) Extension Period	$1.446	$1.446	$1.446	$0.000	$0.000	$0.000	$1.446	$1.446	$1.446
7										
8	**Rider 3 ESM**	($0.043)	($0.043)	($0.043)	$0.000	$0.000	$0.000	($0.043)	($0.043)	($0.043)
9	**Rider 4 Lochburn Land Sale Rebate**	($0.006)	($0.006)	($0.006)	$0.000	$0.000	$0.000	($0.006)	($0.006)	($0.006)
10										
11	Commodity Related Charges									
12	**Commodity Cost Recovery Charge**									
13	(a) Off-Peak Period	$9.780	$9.780	$9.780	($2.244)	($2.244)	($2.244)	$7.536	$7.536	$7.536
14	(b) Extension Period	$9.780	$9.780	$9.780	($2.244)	($2.244)	($2.244)	$7.536	$7.536	$7.536
15										
16	**Midstream Cost Recovery Charge per GJ**									
17	(a) Off-Peak Period	$0.823	$0.812	$0.887	$0.000	$0.000	$0.000	$0.823	$0.812	$0.887
18	(b) Extension Period	$0.823	$0.812	$0.887	$0.000	$0.000	$0.000	$0.823	$0.812	$0.887
19										
20										
21	Subtotal Off -Peak Commodity Related Charges per GJ									
22	(a) Off-Peak Period	$10.603	$10.592	$10.667	($2.244)	($2.244)	($2.244)	$8.359	$8.348	$8.423
23	(b) Extension Period	$10.603	$10.592	$10.667	($2.244)	($2.244)	($2.244)	$8.359	$8.348	$8.423
24										
25										
26										
27	Unauthorized Gas Charge per gigajoule	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
28	during peak period									
29										
30										
31	Total Variable Cost per gigajoule between									
32	(a) Off-Peak Period	$11.271	$11.260	$11.335	($2.244)	($2.244)	($2.244)	$9.027	$9.016	$9.091
33	(b) Extension Period	$12.000	$11.989	$12.064	($2.244)	($2.244)	($2.244)	$9.756	$9.745	$9.820

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Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE Particulars	EXISTING JULY 1, 2008 RATES Lower Mainland	Inland	Columbia	COMMODITY RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	EFFECTIVE OCTOBER 1, 2008 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$551.00	$551.00	$551.00	$0.00	$0.00	$0.00	$551.00	$551.00	$551.00
3										
4	**Demand Charge per gigajoule**	$13.776	$13.776	$13.776	$0.000	$0.000	$0.000	$13.776	$13.776	$13.776
5										
6	**Delivery Charge per GJ**	$0.557	$0.557	$0.557	$0.000	$0.000	$0.000	$0.557	$0.557	$0.557
7										
8	**Rider 3 ESM**	($0.054)	($0.054)	($0.054)	$0.000	$0.000	$0.000	($0.054)	($0.054)	($0.054)
9	**Rider 4 Lochburn Land Sale Rebate**	($0.009)	($0.009)	($0.009)	$0.000	$0.000	$0.000	($0.009)	($0.009)	($0.009)
10										
11										
12	Commodity Related Charges									
13	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$9.780	$9.780	$9.780	($2.244)	($2.244)	($2.244)	$7.536	$7.536	$7.536
14	**Midstream Cost Recovery Charge per GJ**	$0.823	$0.812	$0.887	$0.000	$0.000	$0.000	$0.823	$0.812	$0.887
15	Subtotal Commodity Related Charges per GJ	**$10.603**	**$10.592**	**$10.667**	**($2.244)**	**($2.244)**	**($2.244)**	**$8.359**	**$8.348**	**$8.423**
16										
17										
18										
19	Total Variable Cost per gigajoule	$11.097	$11.086	$11.161	($2.244)	($2.244)	($2.244)	$8.853	$8.842	$8.917

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Line No.	RATE SCHEDULE 6: NGV - STATIONS	EXISTING JULY 1, 2008 RATES			COMMODITY RELATED CHARGES CHANGES			EFFECTIVE OCTOBER 1, 2008 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$58.00	$58.00	$58.00	$0.00	$0.00	$0.00	$58.00	$58.00	$58.00
3										
4	**Delivery Charge per GJ**	$3.194	$3.194	$3.194	$0.000	$0.000	$0.000	$3.194	$3.194	$3.194
5										
6	**Rider 3 ESM**	($0.100)	($0.100)	($0.100)	$0.000	$0.000	$0.000	($0.100)	($0.100)	($0.100)
7	**Rider 4 Lochburn Land Sale Rebate**	($0.020)	($0.020)	($0.020)	$0.000	$0.000	$0.000	($0.020)	($0.020)	($0.020)
8										
9										
10	Commodity Related Charges									
11	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$9.780	$9.780	$9.780	($2.244)	($2.244)	($2.244)	$7.536	$7.536	$7.536
12	**Midstream Cost Recovery Charge per GJ**	$0.452	$0.431	$0.431	$0.000	$0.000	$0.000	$0.452	$0.431	$0.431
13	Subtotal Commodity Related Charges per GJ	**$10.232**	**$10.211**	**$10.211**	**($2.244)**	**($2.244)**	**($2.244)**	**$7.988**	**$7.967**	**$7.967**
14										
15										
16	Total Variable Cost per gigajoule	$13.306	$13.285	$13.285	($2.244)	($2.244)	($2.244)	$11.062	$11.041	$11.041

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
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RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	EXISTING JULY 1, 2008 RATES	COMMODITY RELATED CHARGES CHANGES	EFFECTIVE OCTOBER 1, 2008 RATES
	(1)	(2)	(3)	(4)
1	**LOWER MAINLAND SERVICE AREA**			
2				
3	**Delivery Margin Related Charges**			
4	Basic Charge per month	$81.00	$0.00	$81.00
5				
6	Delivery Charge per GJ	$3.156	$0.000	$3.156
7	Rider 3 ESM	($0.100)	$0.000	($0.100)
8	Rider 4 Lochburn Land Sale Rebate	($0.020)	$0.000	($0.020)
9				
10				
11	**Commodity Related Charges**			
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$9.780	($2.244)	$7.536
13	Midstream Cost Recovery Charge per GJ	$0.452	$0.000	$0.452
14	Subtotal Commodity Related Charges per GJ	$10.232	($2.244)	$7.988
15				
16	Compression Charge per gigajoule	$5.28	$0.000	$5.28
17				
18				
19	**Minimum Charges**	$125.00	$0.00	$125.00
20				
21				
22				
23	Total Variable Cost per gigajoule	$18.548	($2.244)	$16.304

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Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES Particulars	EXISTING JULY 1, 2008 RATES Lower Mainland	 Inland	 Columbia	COMMODITY RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	EFFECTIVE OCTOBER 1, 2008 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$827.00	$827.00	$827.00	$0.00	$0.00	$0.00	$827.00	$827.00	$827.00
3										
4	**Delivery Charge per GJ**	$0.931	$0.931	$0.931	$0.000	$0.000	$0.000	$0.931	$0.931	$0.931
5										
6	**Rider 3 ESM**	($0.034)	($0.034)	($0.034)	$0.000	$0.000	$0.000	($0.034)	($0.034)	($0.034)
7	**Rider 4 Lochburn Land Sale Rebate**	($0.006)	($0.006)	($0.006)	$0.000	$0.000	$0.000	($0.006)	($0.006)	($0.006)
8										
9	Commodity Related Charges									
10	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$9.780	$9.780	$9.780	($2.244)	($2.244)	($2.244)	$7.536	$7.536	$7.536
11	**Midstream Cost Recovery Charge per GJ**	$0.823	$0.812	$0.887	$0.000	$0.000	$0.000	$0.823	$0.812	$0.887
12	Subtotal Commodity Related Charges per GJ	**$10.603**	**$10.592**	**$10.667**	**($2.244)**	**($2.244)**	**($2.244)**	**$8.359**	**$8.348**	**$8.423**
13										
14										
15										
16	Charges per gigajoule for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17										
18										
19										
20										
21										
22	Total Variable Cost per gigajoule	$11.494	$11.483	$11.558	($2.244)	($2.244)	($2.244)	$9.250	$9.239	$9.314

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CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
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Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE	EXISTING OCTOBER 1, 2008 RATES			DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES			EFFECTIVE JANUARY 1, 2009 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$11.13**	**$11.13**	**$11.13**	**$0.86**	**$0.86**	**$0.86**	**$11.99**	**$11.99**	**$11.99**
3										
4	Delivery Charge per GJ	$2.783	$2.783	$2.783	$0.215	$0.215	$0.215	$2.998	$2.998	$2.998
5	Rider 3 ESM	($0.127)	($0.127)	($0.127)	($0.005)	($0.005)	($0.005)	($0.132)	($0.132)	($0.132)
6	Rider 4 Lochburn Land Sale Rebate	($0.022)	($0.022)	($0.022)	$0.000	$0.000	$0.000	($0.022)	($0.022)	($0.022)
7	Rider 5 RSAM	$0.094	$0.094	$0.094	($0.093)	($0.093)	($0.093)	$0.001	$0.001	$0.001
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.728**	**$2.728**	**$2.728**	**$0.117**	**$0.117**	**$0.117**	**$2.845**	**$2.845**	**$2.845**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.209	$1.186	$1.265	($0.267)	($0.283)	($0.284)	$0.942	$0.903	$0.981
13	Rider 8 Unbundling Recovery	$0.117	$0.117	$0.117	($0.044)	($0.044)	($0.044)	$0.073	$0.073	$0.073
14	Subtotal **Midstream Related Charges per GJ**	**$1.326**	**$1.303**	**$1.382**	**($0.311)**	**($0.327)**	**($0.328)**	**$1.015**	**$0.976**	**$1.054**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$7.536**	**$7.536**	**$7.536**	**$0.000**	**$0.000**	**$0.000**	**$7.536**	**$7.536**	**$7.536**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$12.650			($7.449)			$5.201	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$21.372**			**($7.732)**			**$13.640**	
23	per GJ (Includes Rider 1, excludes Riders 8)									

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CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
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Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE Particulars	EXISTING OCTOBER 1, 2008 RATES Lower Mainland	Inland	Columbia	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	EFFECTIVE JANUARY 1, 2009 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$23.35**	**$23.35**	**$23.35**	**$1.80**	**$1.80**	**$1.80**	**$25.15**	**$25.15**	**$25.15**
3										
4	Delivery Charge per GJ	$2.330	$2.330	$2.330	$0.180	$0.180	$0.180	$2.510	$2.510	$2.510
5	Rider 3 ESM	($0.098)	($0.098)	($0.098)	($0.002)	($0.002)	($0.002)	($0.100)	($0.100)	($0.100)
6	Rider 4 Lochburn Land Sale Rebate	($0.017)	($0.017)	($0.017)	$0.000	$0.000	$0.000	($0.017)	($0.017)	($0.017)
7	Rider 5 RSAM	$0.094	$0.094	$0.094	($0.093)	($0.093)	($0.093)	$0.001	$0.001	$0.001
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.309**	**$2.309**	**$2.309**	**$0.085**	**$0.085**	**$0.085**	**$2.394**	**$2.394**	**$2.394**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.303	$1.279	$1.359	($0.356)	($0.372)	($0.373)	$0.947	$0.907	$0.986
13	Rider 8 Unbundling Recovery	$0.047	$0.047	$0.047	($0.068)	($0.068)	($0.068)	($0.021)	($0.021)	($0.021)
14	Subtotal **Midstream Related Charges per GJ**	**$1.350**	**$1.326**	**$1.406**	**($0.424)**	**($0.440)**	**($0.441)**	**$0.926**	**$0.886**	**$0.965**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$7.536**	**$7.536**	**$7.536**	**$0.000**	**$0.000**	**$0.000**	**$7.536**	**$7.536**	**$7.536**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$11.466			($7.360)			$4.106	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$20.281**			**($7.732)**			**$12.549**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

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Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE	EXISTING OCTOBER 1, 2008 RATES			DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES			EFFECTIVE JANUARY 1, 2009 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$124.58**	**$124.58**	**$124.58**	**$9.62**	**$9.62**	**$9.62**	**$134.20**	**$134.20**	**$134.20**
3										
4	Delivery Charge per GJ	$2.008	$2.008	$2.008	$0.155	$0.155	$0.155	$2.163	$2.163	$2.163
5	Rider 3 ESM	($0.075)	($0.075)	($0.075)	($0.004)	($0.004)	($0.004)	($0.079)	($0.079)	($0.079)
6	Rider 4 Lochburn Land Sale Rebate	($0.013)	($0.013)	($0.013)	$0.000	$0.000	$0.000	($0.013)	($0.013)	($0.013)
7	Rider 5 RSAM	$0.094	$0.094	$0.094	($0.093)	($0.093)	($0.093)	$0.001	$0.001	$0.001
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.014**	**$2.014**	**$2.014**	**$0.058**	**$0.058**	**$0.058**	**$2.072**	**$2.072**	**$2.072**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.115	$1.096	$1.175	($0.285)	($0.300)	($0.302)	$0.830	$0.796	$0.873
13	Rider 8 Unbundling Recovery	$0.047	$0.047	$0.047	($0.068)	($0.068)	($0.068)	($0.021)	($0.021)	($0.021)
14	Subtotal **Midstream Related Charges per GJ**	**$1.162**	**$1.143**	**$1.222**	**($0.353)**	**($0.368)**	**($0.370)**	**$0.809**	**$0.775**	**$0.852**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$7.536**	**$7.536**	**$7.536**	**$0.000**	**$0.000**	**$0.000**	**$7.536**	**$7.536**	**$7.536**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$11.649			($7.432)			$4.217	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$20.281**			**($7.732)**			**$12.549**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

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Line No.	RATE SCHEDULE 4: SEASONAL SERVICE Particulars	EXISTING OCTOBER 1, 2008 RATES Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	EFFECTIVE JANUARY 1, 2009 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$413.00	$413.00	$413.00	$32.00	$32.00	$32.00	$445.00	$445.00	$445.00
3										
4	**Delivery Charge per GJ**									
5	(a) Off-Peak Period	$0.717	$0.717	$0.717	$0.055	$0.055	$0.055	$0.772	$0.772	$0.772
6	(b) Extension Period	$1.446	$1.446	$1.446	$0.112	$0.112	$0.112	$1.558	$1.558	$1.558
7										
8	**Rider 3 ESM**	($0.043)	($0.043)	($0.043)	($0.018)	($0.018)	($0.018)	($0.061)	($0.061)	($0.061)
9	**Rider 4 Lochburn Land Sale Rebate**	($0.006)	($0.006)	($0.006)	$0.000	$0.000	$0.000	($0.006)	($0.006)	($0.006)
10										
11	Commodity Related Charges									
12	**Commodity Cost Recovery Charge**									
13	(a) Off-Peak Period	$7.536	$7.536	$7.536	$0.000	$0.000	$0.000	$7.536	$7.536	$7.536
14	(b) Extension Period	$7.536	$7.536	$7.536	$0.000	$0.000	$0.000	$7.536	$7.536	$7.536
15										
16	**Midstream Cost Recovery Charge per GJ**									
17	(a) Off-Peak Period	$0.823	$0.812	$0.887	($0.153)	($0.168)	($0.167)	$0.670	$0.644	$0.720
18	(b) Extension Period	$0.823	$0.812	$0.887	($0.153)	($0.168)	($0.167)	$0.670	$0.644	$0.720
19										
20										
21	Subtotal Off -Peak Commodity Related Charges per GJ									
22	(a) Off-Peak Period	$8.359	$8.348	$8.423	($0.153)	($0.168)	($0.167)	$8.206	$8.180	$8.256
23	(b) Extension Period	$8.359	$8.348	$8.423	($0.153)	($0.168)	($0.167)	$8.206	$8.180	$8.256
24										
25										
26										
27	Unauthorized Gas Charge per gigajoule	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
28	during peak period									
29										
30										
31	Total Variable Cost per gigajoule between									
32	(a) Off-Peak Period	$9.027	$9.016	$9.091	($0.116)	($0.131)	($0.130)	$8.911	$8.885	$8.961
33	(b) Extension Period	$9.756	$9.745	$9.820	($0.059)	($0.074)	($0.073)	$9.697	$9.671	$9.747

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Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE — Particulars	EXISTING OCTOBER 1, 2008 RATES — Lower Mainland	Inland	Columbia	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES — Lower Mainland	Inland	Columbia	EFFECTIVE JANUARY 1, 2009 RATES — Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$551.00	$551.00	$551.00	$43.00	$43.00	$43.00	$594.00	$594.00	$594.00
3										
4	**Demand Charge per gigajoule**	$13.776	$13.776	$13.776	$1.064	$1.064	$1.064	$14.840	$14.840	$14.840
5										
6	**Delivery Charge per GJ**	$0.557	$0.557	$0.557	$0.043	$0.043	$0.043	$0.600	$0.600	$0.600
7										
8	**Rider 3 ESM**	($0.054)	($0.054)	($0.054)	($0.006)	($0.006)	($0.006)	($0.060)	($0.060)	($0.060)
9	**Rider 4 Lochburn Land Sale Rebate**	($0.009)	($0.009)	($0.009)	$0.000	$0.000	$0.000	($0.009)	($0.009)	($0.009)
10										
11										
12	Commodity Related Charges									
13	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$7.536	$7.536	$7.536	$0.000	$0.000	$0.000	$7.536	$7.536	$7.536
14	**Midstream Cost Recovery Charge per GJ**	$0.823	$0.812	$0.887	($0.153)	($0.168)	($0.167)	$0.670	$0.644	$0.720
15	Subtotal Commodity Related Charges per GJ	**$8.359**	**$8.348**	**$8.423**	**($0.153)**	**($0.168)**	**($0.167)**	**$8.206**	**$8.180**	**$8.256**
16										
17										
18										
19	Total Variable Cost per gigajoule	$8.853	$8.842	$8.917	($0.116)	($0.131)	($0.130)	$8.737	$8.711	$8.787

Line No.	RATE SCHEDULE 6: NGV - STATIONS Particulars	EXISTING OCTOBER 1, 2008 RATES Lower Mainland			DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES Lower Mainland			EFFECTIVE JANUARY 1, 2009 RATES Lower Mainland		
			Inland	Columbia		Inland	Columbia		Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$58.00	$58.00	$58.00	$4.00	$4.00	$4.00	$62.00	$62.00	$62.00
3										
4	**Delivery Charge per GJ**	$3.194	$3.194	$3.194	$0.247	$0.247	$0.247	$3.441	$3.441	$3.441
5										
6	**Rider 3 ESM**	($0.100)	($0.100)	($0.100)	($0.010)	($0.010)	($0.010)	($0.110)	($0.110)	($0.110)
7	**Rider 4 Lochburn Land Sale Rebate**	($0.020)	($0.020)	($0.020)	$0.000	$0.000	$0.000	($0.020)	($0.020)	($0.020)
8										
9										
10	Commodity Related Charges									
11	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$7.536	$7.536	$7.536	$0.000	$0.000	$0.000	$7.536	$7.536	$7.536
12	**Midstream Cost Recovery Charge per GJ**	$0.452	$0.431	$0.431	$0.019	$0.015	$0.015	$0.471	$0.446	$0.446
13	Subtotal Commodity Related Charges per GJ	**$7.988**	**$7.967**	**$7.967**	**$0.019**	**$0.015**	**$0.015**	**$8.007**	**$7.982**	**$7.982**
14										
15										
16	Total Variable Cost per gigajoule	$11.062	$11.041	$11.041	$0.256	$0.252	$0.252	$11.318	$11.293	$11.293

RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	EXISTING OCTOBER 1, 2008 RATES	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES	EFFECTIVE JANUARY 1, 2009 RATES
	(1)	(2)	(3)	(4)
1	**LOWER MAINLAND SERVICE AREA**			
2				
3	**Delivery Margin Related Charges**			
4	Basic Charge per month	$81.00	$6.00	$87.00
5				
6	Delivery Charge per GJ	$3.156	$0.244	$3.400
7	Rider 3 ESM	($0.100)	($0.010)	($0.110)
8	Rider 4 Lochburn Land Sale Rebate	($0.020)	$0.000	($0.020)
9				
10				
11	**Commodity Related Charges**			
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$7.536	$0.000	$7.536
13	Midstream Cost Recovery Charge per GJ	$0.452	$0.019	$0.471
14	Subtotal Commodity Related Charges per GJ	$7.988	$0.019	$8.007
15				
16	Compression Charge per gigajoule	$5.28	$0.00	$5.28
17				
18				
19	**Minimum Charges**	$125.00	$0.00	$125.00
20				
21				
22				
23	Total Variable Cost per gigajoule	$16.304	$0.253	$16.557

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Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES	EXISTING OCTOBER 1, 2008 RATES			DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES			EFFECTIVE JANUARY 1, 2009 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$827.00	$827.00	$827.00	$64.00	$64.00	$64.00	$891.00	$891.00	$891.00
3										
4	**Delivery Charge per GJ**	$0.931	$0.931	$0.931	$0.072	$0.072	$0.072	$1.003	$1.003	$1.003
5										
6	**Rider 3 ESM**	($0.034)	($0.034)	($0.034)	($0.002)	($0.002)	($0.002)	($0.036)	($0.036)	($0.036)
7	**Rider 4 Lochburn Land Sale Rebate**	($0.006)	($0.006)	($0.006)	$0.000	$0.000	$0.000	($0.006)	($0.006)	($0.006)
8										
9	Commodity Related Charges									
10	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$7.536	$7.536	$7.536	$0.000	$0.000	$0.000	$7.536	$7.536	$7.536
11	**Midstream Cost Recovery Charge per GJ**	$0.823	$0.812	$0.887	($0.153)	($0.168)	($0.167)	$0.670	$0.644	$0.720
12	Subtotal Commodity Related Charges per GJ	**$8.359**	**$8.348**	**$8.423**	**($0.153)**	**($0.168)**	**($0.167)**	**$8.206**	**$8.180**	**$8.256**
13										
14										
15										
16	Charges per gigajoule for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17										
18										
19										
20										
21										
22	Total Variable Cost per gigajoule	$9.250	$9.239	$9.314	($0.083)	($0.098)	($0.097)	$9.167	$9.141	$9.217

Line No.	**RATE SCHEDULE 22: LARGE INDUSTRIAL T-SERVICE** Particulars	**EXISTING OCTOBER 1, 2008 RATES** Lower Mainland			**DELIVERY MARGIN RELATED CHARGES CHANGES** Lower Mainland			**EFFECTIVE JANUARY 1, 2009 RATES** Lower Mainland		
		Lower Mainland	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$3,444.00	$3,444.00	$3,444.00	$266.00	$266.00	$266.00	$3,710.00	$3,710.00	$3,710.00
2										
3	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.689	$0.689	$0.689	$0.053	$0.053	$0.053	$0.742	$0.742	$0.742
4										
5	**Rider 3 ESM**	($0.024)	($0.024)	($0.024)	$0.001	$0.001	$0.001	($0.023)	($0.023)	($0.023)
6	**Rider 4 Lochburn Land Sale Rebate**	($0.004)	($0.004)	($0.004)	$0.000	$0.000	$0.000	($0.004)	($0.004)	($0.004)
7										
8		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
9	**Charges per gigajoule for UOR Gas**									
10										
11										
12	**Demand Surcharge per gigajoule**	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00	$17.00	$17.00	$17.00
13										
14										
15	**Balancing Service per gigajoule**									
16	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.30	n/a	$0.00	$0.00	n/a	$0.30	$0.30	n/a
17	(b) between and including Nov. 1 and Mar. 31	$1.10	$1.10	n/a	$0.00	$0.00	n/a	$1.10	$1.10	n/a
18										
19								Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
20	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.								
21										
22										
23										
24	**Administration Charge per Month**	$73.00	$73.00	$73.00	$6.00	$6.00	$6.00	$79.00	$79.00	$79.00
25										
26										
27										
28										
29	Total Variable Cost per gigajoule	$0.661	$0.661	$0.661	$0.054	$0.054	$0.054	$0.715	$0.715	$0.715

Line No.	**RATE SCHEDULE 22A: LARGE INDUSTRIAL T-SERVICE** Particulars	**EXISTING OCTOBER 1, 2008 RATES**	**DELIVERY MARGIN RELATED CHARGES CHANGES**	**EFFECTIVE JANUARY 1, 2009 RATES**
	(1)	(2)	(3)	(4)
1	**INLAND SERVICE AREA**			
2				
3	**Basic Charge per Month**	$4,522.00	$349.00	$4,871.00
4				
5	**Delivery Charge per gigajoule - Firm**			
6	(a) Firm DTQ	$11.060	$0.854	$11.914
7	(b) Firm MTQ	$0.077	$0.006	$0.083
8				
9	**Delivery Charge per gigajoule - Interr MTQ**	$0.883	$0.068	$0.951
10				
11	**Rider 3 ESM**	($0.020)	($0.002)	($0.022)
12	**Rider 4 Lochburn Land Sale Rebate**	($0.003)	$0.000	($0.003)
13				
14				
15	**Charges per gigajoule for UOR Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
16				
17				
18	**Demand Surchage per gigajoule**	$17.00	$0.00	$17.00
19				
20	**Balancing Service per gigajoule**			
21	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.00	$0.30
22	(b) between and including Nov. 1 and Mar. 31	$1.10	$0.00	$1.10
23				
24				
25	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
26				
27				
28	**Replacement Gas**	Sumas Daily Price		Sumas Daily Price
29		plus 20 Percent		plus 20 Percent
30				
31	**Administration Charge per Month**	$73.00	$6.00	$79.00
32				
33	Total Variable Cost per gigajoule			
34	(a) Firm MTQ	$0.054	$0.004	$0.058
35	(b) Interruptible MTQ	$0.860	$0.066	$0.926

Line No.	**RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE** Particulars	**EXISTING OCTOBER 1, 2008 RATES** Columbia Except Elkview	Elkview Coal	**DELIVERY MARGIN RELATED CHARGES CHANGES** Columbia Except Elkview	Elkview Coal	**EFFECTIVE JANUARY 1, 2009 RATES** Columbia Except Elkview	Elkview Coal
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**COLUMBIA SERVICE AREA**						
2							
3	**Basic Charge per Month**	$4,265.00	$4,265.00	$329.00	$329.00	$4,594.00	$4,594.00
4							
5	**Delivery Charge per gigajoule - Firm**						
6	(a) Firm DTQ	$7.047	$1.600	$0.544	$0.124	$7.591	$1.724
7	(b) Firm MTQ	$0.075	$0.075	$0.006	$0.006	$0.081	$0.081
8							
9	**Delivery Charge per gigajoule - Interr MTQ**						
10	(a) between and including Apr. 1 and Oct. 31	$0.702	$0.175	$0.054	$0.014	$0.756	$0.189
11	(b) between and including Nov. 1 and Mar.31	$1.012	$0.251	$0.078	$0.019	$1.090	$0.270
12							
13	**Rider 3 ESM**	($0.016)	($0.006)	($0.002)	($0.001)	($0.018)	($0.007)
14	**Rider 4 Lochburn Land Sale Rebate**	($0.003)	($0.002)	$0.000	$0.000	($0.003)	($0.002)
15							
16		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
17	**Charges per gigajoule for UOR Gas**						
18							
19							
20	**Demand Surchage per gigajoule**	$17.00	$17.00	$0.00	$0.00	$17.00	$17.00
21							
22		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
23	**Charges per gigajoule for Backstopping Gas**						
24							
25							
26	**Administration Charge per Month**	$73.00	$73.00	$6.00	$6.00	$79.00	$79.00
27							
28							
29	Total Variable Cost per gigajoule						
30	(a) Firm MTQ	$0.056	$0.067	$0.004	$0.005	$0.060	$0.072
31	(b) Interruptible MTQ - Summer	$0.683	$0.167	$0.052	$0.013	$0.735	$0.180
32	- Winter	$0.993	$0.243	$0.076	$0.018	$1.069	$0.261

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Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE Particulars	EXISTING OCTOBER 1, 2008 RATES Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	EFFECTIVE JANUARY 1, 2009 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$124.58	$124.58	$124.58	$9.62	$9.62	$9.62	$134.20	$134.20	$134.20
2										
3	**Delivery Charge per gigajoule**	$2.008	$2.008	$2.008	$0.155	$0.155	$0.155	$2.163	$2.163	$2.163
4										
5										
6	**Administration Charge per Month**	$73.00	$73.00	$73.00	$6.00	$6.00	$6.00	$79.00	$79.00	$79.00
7										
8	**Sales**									
9	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per gigajoule for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 3 ESM**	($0.075)	($0.075)	($0.075)	($0.004)	($0.004)	($0.004)	($0.079)	($0.079)	($0.079)
15	**Rider 4 Lochburn Land Sale Rebate**	($0.013)	($0.013)	($0.013)	$0.000	$0.000	$0.000	($0.013)	($0.013)	($0.013)
16	**Rider 5 RSAM**	$0.094	$0.094	$0.094	($0.093)	($0.093)	($0.093)	$0.001	$0.001	$0.001
17										
18										
19										
20	Total Variable Cost per gigajoule	$2.014	$2.014	$2.014	$0.058	$0.058	$0.058	$2.072	$2.072	$2.072

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Line No.	**RATE SCHEDULE 25 GENERAL FIRM T-SERVICE** Particulars	**EXISTING OCTOBER 1, 2008 RATES** Lower Mainland			**DELIVERY MARGIN RELATED CHARGES CHANGES** Lower Mainland			**EFFECTIVE JANUARY 1, 2009 RATES** Lower Mainland		
		Lower Mainland	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$551.00	$551.00	$551.00	$43.00	$43.00	$43.00	$594.00	$594.00	$594.00
2										
3	**Demand Charge per gigajoule**	$13.776	$13.776	$13.776	$1.064	$1.064	$1.064	$14.840	$14.840	$14.840
4										
5	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.557	$0.557	$0.557	$0.043	$0.043	$0.043	$0.600	$0.600	$0.600
6										
7	**Administration Charge per Month**	$73.00	$73.00	$73.00	$6.00	$6.00	$6.00	$79.00	$79.00	$79.00
8										
9										
10	**Sales**									
11	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per gigajoule for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per gigajoule for UOR Gas									
15										
16										
17	**Rider 3 ESM**	($0.054)	($0.054)	($0.054)	($0.006)	($0.006)	($0.006)	($0.060)	($0.060)	($0.060)
18	**Rider 4 Lochburn Land Sale Rebate**	($0.009)	($0.009)	($0.009)	$0.000	$0.000	$0.000	($0.009)	($0.009)	($0.009)
19										
20										
21										
22	Total Variable Cost per gigajoule	$0.494	$0.494	$0.494	$0.037	$0.037	$0.037	$0.531	$0.531	$0.531

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
EFFECTIVE JANUARY 1, 2009 RATES
BCUC ORDER NO. G-191-08

Line No.	RATE SCHEDULE 27: INTERRUPTIBLE T-SERVICE	EXISTING OCTOBER 1, 2008 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			EFFECTIVE JANUARY 1, 2009 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$827.00	$827.00	$827.00	$64.00	$64.00	$64.00	$891.00	$891.00	$891.00
2										
3										
4	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.931	$0.931	$0.931	$0.072	$0.072	$0.072	$1.003	$1.003	$1.003
5										
6	**Administration Charge per Month**	$73.00	$73.00	$73.00	$6.00	$6.00	$6.00	$79.00	$79.00	$79.00
7										
8										
9	**Sales**									
10	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
11	(b) Charge per gigajoule for Backstopping Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
17	**Rider 3 ESM**	($0.034)	($0.034)	($0.034)	($0.002)	($0.002)	($0.002)	($0.036)	($0.036)	($0.036)
18	**Rider 4 Lochburn Land Sale Rebate**	($0.006)	($0.006)	($0.006)	$0.000	$0.000	$0.000	($0.006)	($0.006)	($0.006)
19										
20										
21										
22	Total Variable Cost per gigajoule	$0.891	$0.891	$0.891	$0.070	$0.070	$0.070	$0.961	$0.961	$0.961

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
EFFECTIVE APRIL 1, 2009 RATES
BCUC ORDER NO. G-23-09 , G-24-09

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE Particulars	EXISTING JANUARY 1, 2009 RATES Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	EFFECTIVE APRIL 1, 2009 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$11.99**	**$11.99**	**$11.99**	**($0.15)**	**($0.15)**	**($0.15)**	**$11.84**	**$11.84**	**$11.84**
3										
4	Delivery Charge per GJ	$2.998	$2.998	$2.998	($0.037)	($0.037)	($0.037)	$2.961	$2.961	$2.961
5	Rider 3 ESM	($0.132)	($0.132)	($0.132)	$0.000	$0.000	$0.000	($0.132)	($0.132)	($0.132)
6	Rider 4 Delivery Rate Refund	($0.022)	($0.022)	($0.022)	($0.013)	($0.013)	($0.013)	($0.035)	($0.035)	($0.035)
7	Rider 5 RSAM	$0.001	$0.001	$0.001	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.845**	**$2.845**	**$2.845**	**($0.050)**	**($0.050)**	**($0.050)**	**$2.795**	**$2.795**	**$2.795**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$0.942	$0.903	$0.981	$0.000	$0.000	$0.000	$0.942	$0.903	$0.981
13	Rider 8 Unbundling Recovery	$0.073	$0.073	$0.073	$0.000	$0.000	$0.000	$0.073	$0.073	$0.073
14	Subtotal **Midstream Related Charges per GJ**	**$1.015**	**$0.976**	**$1.054**	**$0.000**	**$0.000**	**$0.000**	**$1.015**	**$0.976**	**$1.054**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$7.536**	**$7.536**	**$7.536**	**($1.574)**	**($1.574)**	**($1.574)**	**$5.962**	**$5.962**	**$5.962**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$5.201			($2.576)			$2.625	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$13.640**			**($4.150)**			**$9.490**	
23	per GJ (Includes Rider 1, excludes Riders 8)									

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
EFFECTIVE APRIL 1, 2009 RATES
BCUC ORDER NO. G-23-09 , G-24-09

Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE	EXISTING JANUARY 1, 2009 RATES			DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES			EFFECTIVE APRIL 1, 2009 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$25.15**	**$25.15**	**$25.15**	**($0.31)**	**($0.31)**	**($0.31)**	**$24.84**	**$24.84**	**$24.84**
3										
4	Delivery Charge per GJ	$2.510	$2.510	$2.510	($0.031)	($0.031)	($0.031)	$2.479	$2.479	$2.479
5	Rider 3 ESM	($0.100)	($0.100)	($0.100)	$0.000	$0.000	$0.000	($0.100)	($0.100)	($0.100)
6	Rider 4 Delivery Rate Refund	($0.017)	($0.017)	($0.017)	($0.012)	($0.012)	($0.012)	($0.029)	($0.029)	($0.029)
7	Rider 5 RSAM	$0.001	$0.001	$0.001	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.394**	**$2.394**	**$2.394**	**($0.043)**	**($0.043)**	**($0.043)**	**$2.351**	**$2.351**	**$2.351**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$0.947	$0.907	$0.986	$0.000	$0.000	$0.000	$0.947	$0.907	$0.986
13	Rider 8 Unbundling Recovery	($0.021)	($0.021)	($0.021)	$0.000	$0.000	$0.000	($0.021)	($0.021)	($0.021)
14	Subtotal **Midstream Related Charges per GJ**	**$0.926**	**$0.886**	**$0.965**	**$0.000**	**$0.000**	**$0.000**	**$0.926**	**$0.886**	**$0.965**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$7.536**	**$7.536**	**$7.536**	**($1.574)**	**($1.574)**	**($1.574)**	**$5.962**	**$5.962**	**$5.962**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$4.106			($2.576)			$1.530	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$12.549**			**($4.150)**			**$8.399**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

BCUC ORDER NO. G-23-09 , G-24-09

Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE Particulars	EXISTING JANUARY 1, 2009 RATES Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	EFFECTIVE APRIL 1, 2009 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$134.20**	**$134.20**	**$134.20**	**($1.68)**	**($1.68)**	**($1.68)**	**$132.52**	**$132.52**	**$132.52**
3										
4	Delivery Charge per GJ	$2.163	$2.163	$2.163	($0.027)	($0.027)	($0.027)	$2.136	$2.136	$2.136
5	Rider 3 ESM	($0.079)	($0.079)	($0.079)	$0.000	$0.000	$0.000	($0.079)	($0.079)	($0.079)
6	Rider 4 Delivery Rate Refund	($0.013)	($0.013)	($0.013)	($0.008)	($0.008)	($0.008)	($0.021)	($0.021)	($0.021)
7	Rider 5 RSAM	$0.001	$0.001	$0.001	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.072**	**$2.072**	**$2.072**	**($0.035)**	**($0.035)**	**($0.035)**	**$2.037**	**$2.037**	**$2.037**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$0.830	$0.796	$0.873	$0.000	$0.000	$0.000	$0.830	$0.796	$0.873
13	Rider 8 Unbundling Recovery	($0.021)	($0.021)	($0.021)	$0.000	$0.000	$0.000	($0.021)	($0.021)	($0.021)
14	Subtotal **Midstream Related Charges per GJ**	**$0.809**	**$0.775**	**$0.852**	**$0.000**	**$0.000**	**$0.000**	**$0.809**	**$0.775**	**$0.852**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$7.536**	**$7.536**	**$7.536**	**($1.574)**	**($1.574)**	**($1.574)**	**$5.962**	**$5.962**	**$5.962**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$4.217			($2.576)			$1.641	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$12.549**			**($4.150)**			**$8.399**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

BCUC ORDER NO. G-23-09

Line No.	RATE SCHEDULE 4: SEASONAL SERVICE Particulars	EXISTING JANUARY 1, 2009 RATES Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	EFFECTIVE APRIL 1, 2009 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$445.00	$445.00	$445.00	($6.00)	($6.00)	($6.00)	$439.00	$439.00	$439.00
3										
4	**Delivery Charge per GJ**									
5	(a) Off-Peak Period	$0.772	$0.772	$0.772	($0.010)	($0.010)	($0.010)	$0.762	$0.762	$0.762
6	(b) Extension Period	$1.558	$1.558	$1.558	($0.019)	($0.019)	($0.019)	$1.539	$1.539	$1.539
7										
8	**Rider 3 ESM**	($0.061)	($0.061)	($0.061)	$0.000	$0.000	$0.000	($0.061)	($0.061)	($0.061)
9	**Rider 4 Delivery Rate Refund**	($0.006)	($0.006)	($0.006)	$0.005	$0.005	$0.005	($0.001)	($0.001)	($0.001)
10										
11	Commodity Related Charges									
12	**Commodity Cost Recovery Charge**									
13	(a) Off-Peak Period	$7.536	$7.536	$7.536	($1.574)	($1.574)	($1.574)	$5.962	$5.962	$5.962
14	(b) Extension Period	$7.536	$7.536	$7.536	($1.574)	($1.574)	($1.574)	$5.962	$5.962	$5.962
15										
16	**Midstream Cost Recovery Charge per GJ**									
17	(a) Off-Peak Period	$0.670	$0.644	$0.720	$0.000	$0.000	$0.000	$0.670	$0.644	$0.720
18	(b) Extension Period	$0.670	$0.644	$0.720	$0.000	$0.000	$0.000	$0.670	$0.644	$0.720
19										
20										
21	Subtotal Off -Peak Commodity Related Charges per GJ									
22	(a) Off-Peak Period	$8.206	$8.180	$8.256	($1.574)	($1.574)	($1.574)	$6.632	$6.606	$6.682
23	(b) Extension Period	$8.206	$8.180	$8.256	($1.574)	($1.574)	($1.574)	$6.632	$6.606	$6.682
24										
25										
26										
27	Unauthorized Gas Charge per gigajoule	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
28	during peak period									
29										
30										
31	Total Variable Cost per gigajoule between									
32	(a) Off-Peak Period	$8.911	$8.885	$8.961	($1.579)	($1.579)	($1.579)	$7.332	$7.306	$7.382
33	(b) Extension Period	$9.697	$9.671	$9.747	($1.588)	($1.588)	($1.588)	$8.109	$8.083	$8.159

BCUC ORDER NO. G-23-09

Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE	EXISTING JANUARY 1, 2009 RATES			DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES			EFFECTIVE APRIL 1, 2009 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$594.00	$594.00	$594.00	($7.00)	($7.00)	($7.00)	$587.00	$587.00	$587.00
3										
4	**Demand Charge per gigajoule**	$14.840	$14.840	$14.840	($0.185)	($0.185)	($0.185)	$14.655	$14.655	$14.655
5										
6	**Delivery Charge per GJ**	$0.600	$0.600	$0.600	($0.007)	($0.007)	($0.007)	$0.593	$0.593	$0.593
7										
8	**Rider 3 ESM**	($0.060)	($0.060)	($0.060)	$0.000	$0.000	$0.000	($0.060)	($0.060)	($0.060)
9	**Rider 4 Delivery Rate Refund**	($0.009)	($0.009)	($0.009)	($0.009)	($0.009)	($0.009)	($0.018)	($0.018)	($0.018)
10										
11										
12	Commodity Related Charges									
13	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$7.536	$7.536	$7.536	($1.574)	($1.574)	($1.574)	$5.962	$5.962	$5.962
14	**Midstream Cost Recovery Charge per GJ**	$0.670	$0.644	$0.720	$0.000	$0.000	$0.000	$0.670	$0.644	$0.720
15	Subtotal Commodity Related Charges per GJ	**$8.206**	**$8.180**	**$8.256**	**($1.574)**	**($1.574)**	**($1.574)**	**$6.632**	**$6.606**	**$6.682**
16										
17										
18										
19	Total Variable Cost per gigajoule	$8.737	$8.711	$8.787	($1.590)	($1.590)	($1.590)	$7.147	$7.121	$7.197

BCUC ORDER NO. G-23-09

Line No.	RATE SCHEDULE 6: NGV - STATIONS	EXISTING JANUARY 1, 2009 RATES			DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES			EFFECTIVE APRIL 1, 2009 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$62.00	$62.00	$62.00	($1.00)	($1.00)	($1.00)	$61.00	$61.00	$61.00
3										
4	**Delivery Charge per GJ**	$3.441	$3.441	$3.441	($0.043)	($0.043)	($0.043)	$3.398	$3.398	$3.398
5										
6	**Rider 3 ESM**	($0.110)	($0.110)	($0.110)	$0.000	$0.000	$0.000	($0.110)	($0.110)	($0.110)
7	**Rider 4 Delivery Rate Refund**	($0.020)	($0.020)	($0.020)	$0.001	$0.001	$0.001	($0.019)	($0.019)	($0.019)
8										
9										
10	Commodity Related Charges									
11	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$7.536	$7.536	$7.536	($1.574)	($1.574)	($1.574)	$5.962	$5.962	$5.962
12	**Midstream Cost Recovery Charge per GJ**	$0.471	$0.446	$0.446	$0.000	$0.000	$0.000	$0.471	$0.446	$0.446
13	Subtotal Commodity Related Charges per GJ	**$8.007**	**$7.982**	**$7.982**	**($1.574)**	**($1.574)**	**($1.574)**	**$6.433**	**$6.408**	**$6.408**
14										
15										
16	Total Variable Cost per gigajoule	$11.318	$11.293	$11.293	($1.616)	($1.616)	($1.616)	$9.702	$9.677	$9.677

RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	EXISTING JANUARY 1, 2009 RATES	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES	EFFECTIVE APRIL 1, 2009 RATES
	(1)	(2)	(3)	(4)
1	**LOWER MAINLAND SERVICE AREA**			
2				
3	**Delivery Margin Related Charges**			
4	Basic Charge per month	$87.00	($1.00)	$86.00
5				
6	Delivery Charge per GJ	$3.400	($0.042)	$3.358
7	Rider 3 ESM	($0.110)	$0.000	($0.110)
8	Rider 4 Delivery Rate Refund	($0.020)	$0.001	($0.019)
9				
10				
11	**Commodity Related Charges**			
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$7.536	($1.574)	$5.962
13	Midstream Cost Recovery Charge per GJ	$0.471	$0.000	$0.471
14	Subtotal Commodity Related Charges per GJ	$8.007	($1.574)	$6.433
15				
16	Compression Charge per gigajoule	$5.28	$0.00	$5.28
17				
18				
19	**Minimum Charges**	$125.00	$0.00	$125.00
20				
21				
22				
23	Total Variable Cost per gigajoule	$16.557	($1.615)	$14.942

Line No.	**RATE SCHEDULE 7: INTERRUPTIBLE SALES**	**EXISTING JANUARY 1, 2009 RATES**			**DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES**			**EFFECTIVE APRIL 1, 2009 RATES**		
	Particulars	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$891.00	$891.00	$891.00	($11.00)	($11.00)	($11.00)	$880.00	$880.00	$880.00
3										
4	**Delivery Charge per GJ**	$1.003	$1.003	$1.003	($0.013)	($0.013)	($0.013)	$0.990	$0.990	$0.990
5										
6	**Rider 3 ESM**	($0.036)	($0.036)	($0.036)	$0.000	$0.000	$0.000	($0.036)	($0.036)	($0.036)
7	**Rider 4 Delivery Rate Refund**	($0.006)	($0.006)	($0.006)	$0.006	$0.006	$0.006	$0.000	$0.000	$0.000
8										
9	Commodity Related Charges									
10	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$7.536	$7.536	$7.536	($1.574)	($1.574)	($1.574)	$5.962	$5.962	$5.962
11	**Midstream Cost Recovery Charge per GJ**	$0.670	$0.644	$0.720	$0.000	$0.000	$0.000	$0.670	$0.644	$0.720
12	Subtotal Commodity Related Charges per GJ	**$8.206**	**$8.180**	**$8.256**	**($1.574)**	**($1.574)**	**($1.574)**	**$6.632**	**$6.606**	**$6.682**
13										
14										
15		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
16	Charges per gigajoule for UOR Gas									
17										
18										
19										
20										
21										
22	Total Variable Cost per gigajoule	$9.167	$9.141	$9.217	($1.581)	($1.581)	($1.581)	$7.586	$7.560	$7.636

BCUC ORDER NO. G-23-09

Line No.	RATE SCHEDULE 22: LARGE INDUSTRIAL T-SERVICE	EXISTING JANUARY 1, 2009 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			EFFECTIVE APRIL 1, 2009 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$3,710.00	$3,710.00	$3,710.00	($46.00)	($46.00)	($46.00)	$3,664.00	$3,664.00	$3,664.00
2										
3	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.742	$0.742	$0.742	($0.009)	($0.009)	($0.009)	$0.733	$0.733	$0.733
4										
5	**Rider 3 ESM**	($0.023)	($0.023)	($0.023)	$0.000	$0.000	$0.000	($0.023)	($0.023)	($0.023)
6	**Rider 4 Delivery Rate Refund**	($0.004)	($0.004)	($0.004)	($0.001)	($0.001)	($0.001)	($0.005)	($0.005)	($0.005)
7										
8		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
9	**Charges per gigajoule for UOR Gas**									
10										
11										
12	**Demand Surcharge per gigajoule**	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00	$17.00	$17.00	$17.00
13										
14										
15	**Balancing Service per gigajoule**									
16	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.30	n/a	$0.00	$0.00	n/a	$0.30	$0.30	n/a
17	(b) between and including Nov. 1 and Mar. 31	$1.10	$1.10	n/a	$0.00	$0.00	n/a	$1.10	$1.10	n/a
18										
19										
20	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
21										
22										
23										
24	**Administration Charge per Month**	$79.00	$79.00	$79.00	($1.00)	($1.00)	($1.00)	$78.00	$78.00	$78.00
25										
26										
27										
28										
29	Total Variable Cost per gigajoule	$0.715	$0.715	$0.715	($0.010)	($0.010)	($0.010)	$0.705	$0.705	$0.705

RATE SCHEDULE 22A:
LARGE INDUSTRIAL T-SERVICE

Line No.	Particulars	EXISTING JANUARY 1, 2009 RATES	DELIVERY MARGIN RELATED CHARGES CHANGES	EFFECTIVE APRIL 1, 2009 RATES
	(1)	(2)	(3)	(4)
1	**INLAND SERVICE AREA**			
2				
3	**Basic Charge per Month**	$4,871.00	($61.00)	$4,810.00
4				
5	**Delivery Charge per gigajoule - Firm**			
6	(a) Firm DTQ	$11.914	($0.149)	$11.765
7	(b) Firm MTQ	$0.083	($0.001)	$0.082
8				
9	**Delivery Charge per gigajoule - Interr MTQ**	$0.951	($0.012)	$0.939
10				
11	**Rider 3 ESM**	($0.022)	$0.000	($0.022)
12	**Rider 4 Delivery Rate Refund**	($0.003)	$0.000	($0.003)
13				
14				
15	**Charges per gigajoule for UOR Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
16				
17				
18	**Demand Surchage per gigajoule**	$17.00	$0.00	$17.00
19				
20	**Balancing Service per gigajoule**			
21	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.00	$0.30
22	(b) between and including Nov. 1 and Mar. 31	$1.10	$0.00	$1.10
23				
24				
25	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
26				
27				
28	**Replacement Gas**	Sumas Daily Price		Sumas Daily Price
29		plus 20 Percent		plus 20 Percent
30				
31	**Administration Charge per Month**	$79.00	($1.00)	$78.00
32				
33	Total Variable Cost per gigajoule			
34	(a) Firm MTQ	$0.058	($0.001)	$0.057
35	(b) Interruptible MTQ	$0.926	($0.012)	$0.914

RATE SCHEDULE 22B:
LARGE INDUSTRIAL T-SERVICE

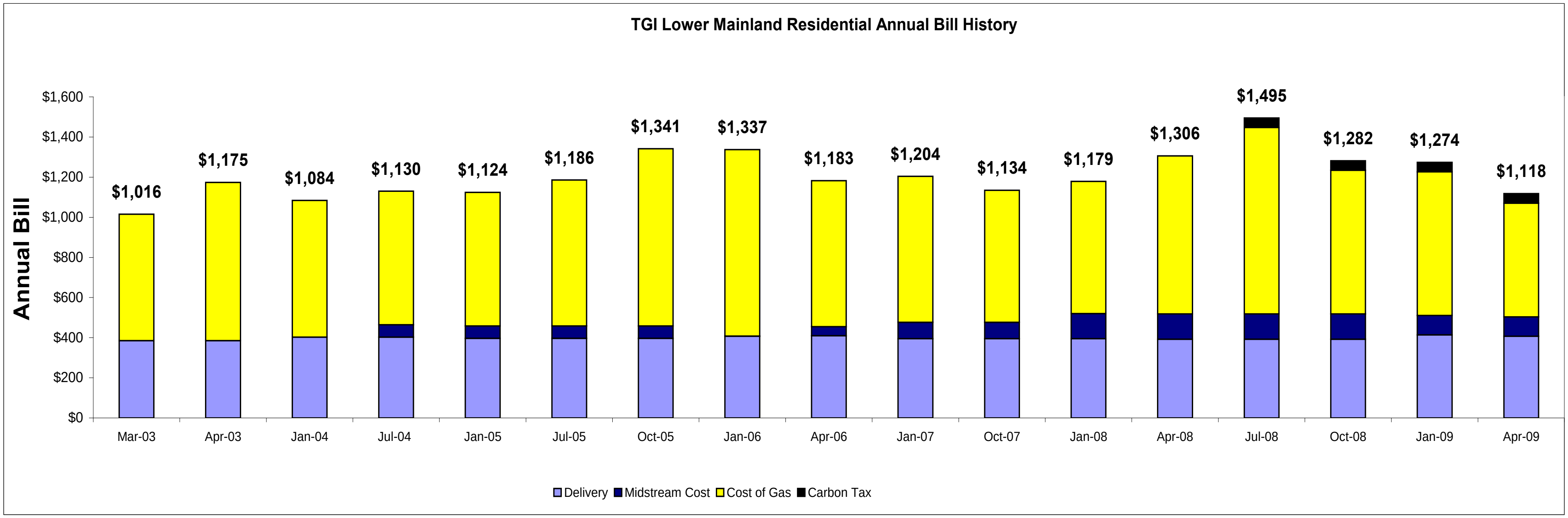
Line No.	Particulars	EXISTING JANUARY 1, 2009 RATES Columbia Except Elkview	Elkview Coal	DELIVERY MARGIN RELATED CHARGES CHANGES Columbia Except Elkview	Elkview Coal	EFFECTIVE APRIL 1, 2009 RATES Columbia Except Elkview	Elkview Coal
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**COLUMBIA SERVICE AREA**						
2							
3	**Basic Charge per Month**	$4,594.00	$4,594.00	($57.00)	($57.00)	$4,537.00	$4,537.00
4							
5	**Delivery Charge per gigajoule - Firm**						
6	(a) Firm DTQ	$7.591	$1.724	($0.095)	($0.022)	$7.496	$1.702
7	(b) Firm MTQ	$0.081	$0.081	($0.001)	($0.001)	$0.080	$0.080
8							
9	**Delivery Charge per gigajoule - Interr MTQ**						
10	(a) between and including Apr. 1 and Oct. 31	$0.756	$0.189	($0.009)	($0.002)	$0.747	$0.187
11	(b) between and including Nov. 1 and Mar.31	$1.090	$0.270	($0.014)	($0.003)	$1.076	$0.267
12							
13	**Rider 3 ESM**	($0.018)	($0.007)	$0.000	$0.000	($0.018)	($0.007)
14	**Rider 4 Delivery Rate Refund**	($0.003)	($0.002)	$0.000	($0.001)	($0.003)	($0.003)
15							
16		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
17	**Charges per gigajoule for UOR Gas**						
18							
19							
20	**Demand Surchage per gigajoule**	$17.00	$17.00	$0.00	$0.00	$17.00	$17.00
21							
22		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
23	**Charges per gigajoule for Backstopping Gas**						
24							
25							
26	**Administration Charge per Month**	$79.00	$79.00	($1.00)	($1.00)	$78.00	$78.00
27							
28							
29	Total Variable Cost per gigajoule						
30	(a) Firm MTQ	$0.060	$0.072	($0.001)	($0.002)	$0.059	$0.070
31	(b) Interruptible MTQ - Summer	$0.735	$0.180	($0.009)	($0.003)	$0.726	$0.177
32	- Winter	$1.069	$0.261	($0.014)	($0.004)	$1.055	$0.257

Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE Particulars	EXISTING JANUARY 1, 2009 RATES Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	EFFECTIVE APRIL 1, 2009 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$134.20	$134.20	$134.20	($1.68)	($1.68)	($1.68)	$132.52	$132.52	$132.52
2										
3	**Delivery Charge per gigajoule**	$2.163	$2.163	$2.163	($0.027)	($0.027)	($0.027)	$2.136	$2.136	$2.136
4										
5										
6	**Administration Charge per Month**	$79.00	$79.00	$79.00	($1.00)	($1.00)	($1.00)	$78.00	$78.00	$78.00
7										
8	**Sales**									
9	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per gigajoule for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 3 ESM**	($0.079)	($0.079)	($0.079)	$0.000	$0.000	$0.000	($0.079)	($0.079)	($0.079)
15	**Rider 4 Delivery Rate Refund**	($0.013)	($0.013)	($0.013)	($0.009)	($0.009)	($0.009)	($0.022)	($0.022)	($0.022)
16	**Rider 5 RSAM**	$0.001	$0.001	$0.001	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001
17										
18										
19										
20	Total Variable Cost per gigajoule	$2.072	$2.072	$2.072	($0.036)	($0.036)	($0.036)	$2.036	$2.036	$2.036

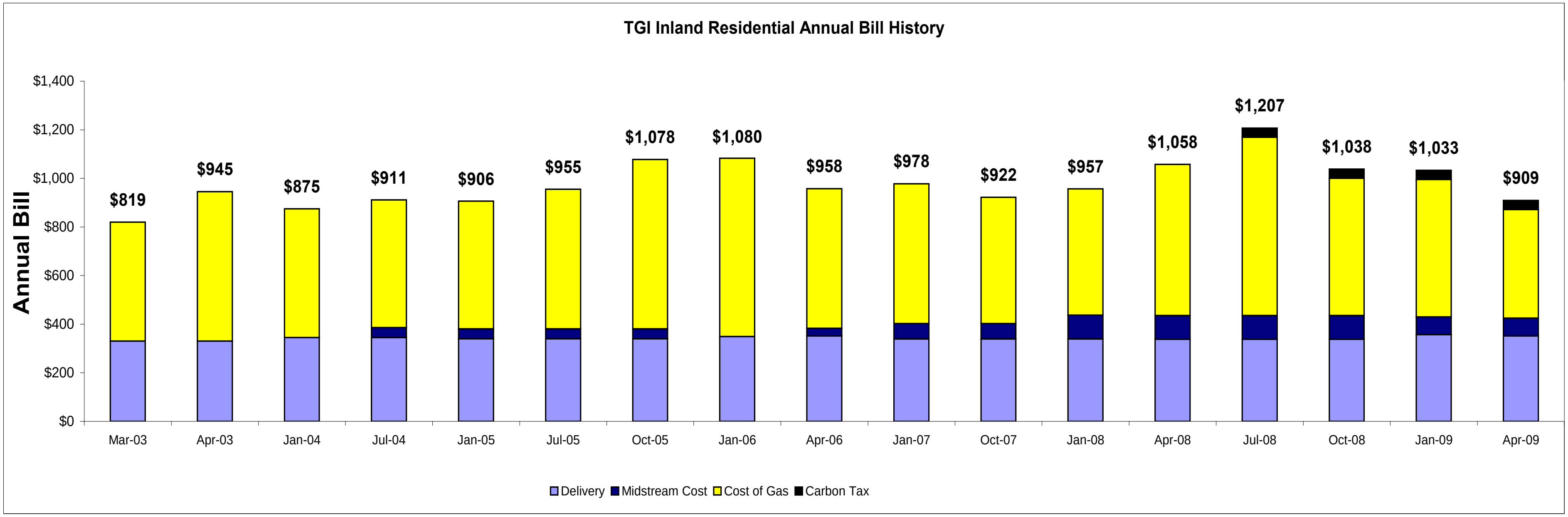
Line No.	RATE SCHEDULE 25 GENERAL FIRM T-SERVICE Particulars	EXISTING JANUARY 1, 2009 RATES Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	EFFECTIVE APRIL 1, 2009 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$594.00	$594.00	$594.00	($7.00)	($7.00)	($7.00)	$587.00	$587.00	$587.00
2										
3	**Demand Charge per gigajoule**	$14.840	$14.840	$14.840	($0.185)	($0.185)	($0.185)	$14.655	$14.655	$14.655
4										
5	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.600	$0.600	$0.600	($0.007)	($0.007)	($0.007)	$0.593	$0.593	$0.593
6										
7	**Administration Charge per Month**	$79.00	$79.00	$79.00	($1.00)	($1.00)	($1.00)	$78.00	$78.00	$78.00
8										
9										
10	**Sales**									
11	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per gigajoule for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per gigajoule for UOR Gas									
15										
16										
17	**Rider 3 ESM**	($0.060)	($0.060)	($0.060)	$0.000	$0.000	$0.000	($0.060)	($0.060)	($0.060)
18	**Rider 4 Delivery Rate Refund**	($0.009)	($0.009)	($0.009)	($0.003)	($0.003)	($0.003)	($0.012)	($0.012)	($0.012)
19										
20										
21										
22	Total Variable Cost per gigajoule	$0.531	$0.531	$0.531	($0.010)	($0.010)	($0.010)	$0.521	$0.521	$0.521

BCUC ORDER NO. G-23-09

Line No.	RATE SCHEDULE 27: INTERRUPTIBLE T-SERVICE	EXISTING JANUARY 1, 2009 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			EFFECTIVE APRIL 1, 2009 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$891.00	$891.00	$891.00	($11.00)	($11.00)	($11.00)	$880.00	$880.00	$880.00
2										
3										
4	**Delivery Charge per gigajoule (Interr. MTQ)**	$1.003	$1.003	$1.003	($0.013)	($0.013)	($0.013)	$0.990	$0.990	$0.990
5										
6	**Administration Charge per Month**	$79.00	$79.00	$79.00	($1.00)	($1.00)	($1.00)	$78.00	$78.00	$78.00
7										
8										
9	**Sales**									
10	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
11	(b) Charge per gigajoule for Backstopping Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
17	**Rider 3 ESM**	($0.036)	($0.036)	($0.036)	$0.000	$0.000	$0.000	($0.036)	($0.036)	($0.036)
18	**Rider 4 Delivery Rate Refund**	($0.006)	($0.006)	($0.006)	($0.002)	($0.002)	($0.002)	($0.008)	($0.008)	($0.008)
19										
20										
21										
22	Total Variable Cost per gigajoule	$0.961	$0.961	$0.961	($0.015)	($0.015)	($0.015)	$0.946	$0.946	$0.946



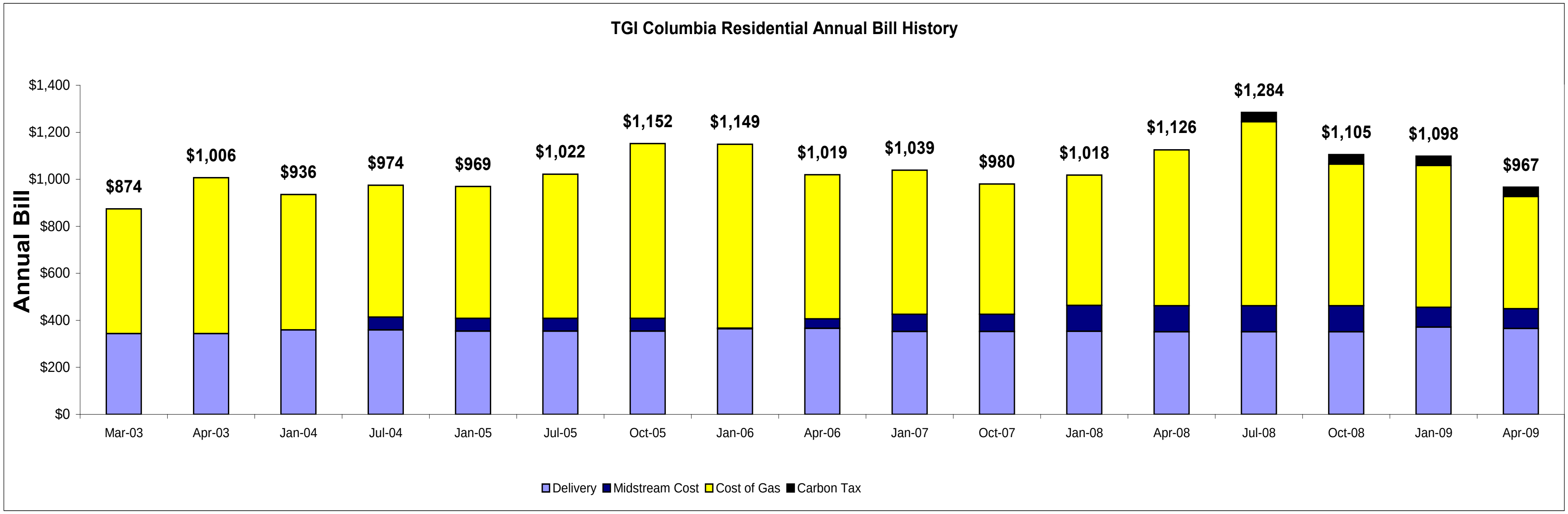
Assumes:
Natural gas use of 95 GJ
Terasen Gas amount includes the basic charge



Assumes:

Natural gas use of 75 GJ

Terasen Gas amount includes the basic charge



Assumes:
Natural gas use of 80 GJ
Terasen Gas amount includes the basic charge

Standard Fees and Charges Schedule

Application Fee		
Existing Installation	$25.00	
New Installation	$25.00	
New Installation - Manifold Meters	$25.00 per meter	R
New Installation - Vertical Subdivision	$25.00 per meter	
Service Line Cost Allowance		
Other than a duplex	$1,535.00	
Duplex	$3,070.00	

Administrative Charges

Late Payment Charge	1.5% per month (19.56% per annum) on outstanding balance	
Dishonoured Cheque Charge	$20.00	

Interest on Cash Security Deposits

Terasen Gas will pay interest on cash security deposits at Terasen Gas' prime interest rate minus 2%. Terasen Gas prime interest rate is defined as the floating annual rate of interest which is equal to the rate of interest declared from time to time by Terasen Gas' lead bank as its "prime rate" for loans in Canadian dollars.

Payment of interest will be credited to the Customer's account in January of each Year.

Metering Related Charges

Disputed Meter Testing Fees

Meters rated at less than or equal to 14.2 m^3/Hour	$60.00	A
Meters rated greater than 14.2 m^3/Hour	Actual Costs of Removal and Replacement	

Standard Fees and Charges Schedule

Application Fee		
Existing Installation	$25.00	
New Installation	$~~8~~25.00	
New Installation - Manifold Meters	$~~8~~25.00 per meter	
New Installation - Vertical Subdivision	$~~8~~25.00 per meter	
		O
Service Line Cost Allowance		
Other than a duplex	$1,535.00	A
Duplex	$3,070.00	

Administrative Charges

Late Payment Charge	1.5% per month (19.56% per annum) on outstanding balance
Dishonoured Cheque Charge	$20.00

Interest on Cash Security Deposits

Terasen Gas will pay interest on cash security deposits at Terasen Gas' prime interest rate minus 2%. Terasen Gas prime interest rate is defined as the floating annual rate of interest which is equal to the rate of interest declared from time to time by Terasen Gas' lead bank as its "prime rate" for loans in Canadian dollars.

Payment of interest will be credited to the Customer's account in January of each Year.

Metering Related Charges

Disputed Meter Testing Fees

Meters rated at less than or equal to 14.2 m^3/Hour	$~~3~~60.00
Meters rated greater than 14.2 m^3/Hour	Actual Costs of Removal and Replacement

12A. Alternative Energy Extensions

12A.1 **Sy stem Expansion** - Terasen Gas will make extensions to the Terasen Gas System using technology that produces alternative energy, in accordance with the provisions of this section. The alternative energy extensions include geo-exchange, solar-thermal and district energy systems which are described below:

Geo-exchange systems, also referred to as geo-thermal systems, earth exchange systems or ground and water source heat pumps, utilize the latent heat energy contained in near surface layers of the earth, ground water and surface water. A subsurface piping system contains a liquid that absorbs heat from the surrounding material and delivers it to a central heat exchanger. High efficiency heat pumps convert this latent energy into hot water or steam contained in a separate piping system that can then deliver the heat energy to where it is required for space heating and hot water uses. Centralized equipment is usually contained within specifically designed mechanical room that serves the entire development. The heat exchanger is reversed to provide space cooling, removing heat from the building(s) and returning it to the subsurface substrate.

Solar-thermal water heating systems, also called solar hybrid water heating systems, are a system of solar collection tubes and piping capture heat energy from the suns rays and deliver it to a central heat exchanger, where it is converted to domestic hot water and distributed in a manner similar to that described above for geo-exchange systems. The solar collection tubes are located outside the building or buildings, typically on the roof, while centralized equipment is again housed in a specifically designed mechanical room.

District energy systems employ a range of energy technologies and sources to deliver piped heating (steam or hot water) and/or cooling (cool water) to multiple buildings and customers within a neighbourhood from a central plant location or locations.

12A.2 **Ownership** - All alternative energy extensions will remain the property of Terasen Gas.

12A.3 **Cost of Service Model** - All applications by Customers for service using an alternative energy extension will be subject to review using a cost of service model. The cost of service model will determine the rate that a customer will pay for the service associated with the alternative energy extension. Service will be provided under the terms and conditions of the Service Agreement between Terasen Gas and the Customer.

12A.4 **Projected Energy Consumption/Number of Customers** - The projected energy consumption and number of customers to be used in the cost of service model will be determined by Terasen Gas by

(a) estimating the number of Customers to be served by the alternative energy extension;

(b) if applicable, establishing consumption estimates for each Customer; and

(c) projecting when the Customer will be connected to the alternative energy extension.

If applicable, the projection will take into consideration the estimated number and type of thermal appliances used and the effect variations in weather conditions throughout the applicable Service Area have on consumption. All Customers expected to connect to the alternative energy extension will be considered in the cost of service model.

12A.5 **Costs** - The total costs to be used in the cost of service model include, without limitation

(a) the full labour, material, and other costs necessary to serve the new Customers less any contributions in aid of construction by the Customers or third parties, grants, tax credits, or non-financial factors offsetting the full costs that are deemed to be acceptable by the British Columbia Utilities Commission;

(b) the appropriate allocation of Terasen Gas' overheads associated with the construction of the alternative energy extension;

(c) depreciation expense related to the capital equipment associated with the alternative energy extension; and

(d) the incremental operating and maintenance expenses necessary to serve the Customers.

In addition to the costs identified, the cost of service model will include applicable taxes and the appropriate return on investment as approved by the British Columbia Utilities Commission.

TERASEN GAS INC.

RATE SCHEDULE 26
NGV TRANSPORTATION SERVICE

Effective January 1, 2010

TABLE OF CONTENTS

Section **Page**

1. Definitions

1.1 **Definitions** - Except where the context requires otherwise all words and phrases defined below or in the General Terms and Conditions of Terasen Gas and used in this Rate Schedule or in a Transportation Agreement have the meanings set out below or in the General Terms and Conditions of Terasen Gas. Where any of the definitions set out below conflict with the definitions in the General Terms and Conditions of Terasen Gas, the definitions set out below govern.

(a) **Authorized Quantity** - means the quantity of energy (in Gigajoules) for each Day approved by the Transporter(s) for transportation service on the Transporter's pipeline system, based on the quantity requested pursuant to section 7.2 (Requested Quantity), adjusted as set out in section 7.3 (Adjustment of Requested Quantity) or the quantity of energy approved for sale by Terasen Gas under an applicable Rate Schedule, or any component or aggregate of these quantities, as the context requires.

(b) **Backstopping Gas** - means Gas made available by Terasen Gas as an interruptible backup supply if on any Day the Authorized Quantity is less than the Requested Quantity, adjusted as set out in section 7.3 (Adjustment of Requested Quantity).

(c) **Balancing Gas** - means any Gas taken during a Month which is in excess of the Authorized Quantity, subject to section 8.1 (Monthly Adjustments).

(d) **Business Day** - means a Day that commences on other than a Saturday, a Sunday, or a statutory holiday in the Province of British Columbia.

(e) **Capacity Factor** - means the Shipper's average daily use of Gas divided by the product of the average daily use of Gas for the Month of greatest use during the winter period (November 1 to March 31) multiplied by 1.25.

(f) **Commencement Date** - means the day specified as the Commencement Date in the Transportation Agreement.

(g) **Contract Year** - means a period of 12 consecutive Months commencing at the beginning of the 1st Day of November and ending at the beginning of the next succeeding 1st Day of November.

(h) **Day** - means, subject to section 1.2 (Change in Definition of "Day"), any period of twenty-four consecutive hours beginning and ending at 7:00 a.m. Pacific Standard Time.

(i) **Delivery Point** - means the point specified in a Transportation Agreement where Terasen Gas delivers Gas to a Shipper.

(j) **DTQ or Daily Transportation Quantity** - means the maximum quantity of Gas that Terasen Gas is obligated to transport for and deliver to a Shipper at the Delivery Point on any particular Day, which in the discretion of Terasen Gas reasonably reflects the Shipper's requirements and which is specified in a Transportation Agreement.

(k) **EKE** - means the East Kootenay Exchange, an Interconnection Point where the Terasen Gas System interconnects with the facilities of TransCanada PipeLines Limited, B.C. System.

(l) **Firm EKE Receipt Service** - means the firm receipt service by which the Shipper provides Gas to Terasen Gas at EKE for firm transportation to a Delivery Point in the Inland Service Area, as described in section 11.1.

(m) **Force Majeure** - means any acts of God, strikes, lockouts, or other industrial disturbances, civil disturbances, arrests and restraints of rulers or people, interruptions by government or court orders, present or future valid orders of any regulatory body having proper jurisdiction, acts of the public enemy, wars, riots, blackouts, insurrections, failure or inability to secure materials or labour by reason of regulations or orders of government, serious epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, explosions, breakage or accident to machinery or lines of pipes, or freezing of wells or pipelines, or the failure of gas supply, temporary or otherwise, from a Supplier of gas, which act of Force Majeure was not due to negligence of the party claiming Force Majeure. Further, Force Majeure will also include a declaration of force majeure by a Transporter that results in Gas being unavailable for delivery at the Interconnection Point.

(n) **Group** - means a group of Shippers who each transport Gas under a transportation Rate Schedule, have a common Shipper Agent, and who have each entered into a Transportation Agreement.

(o) **Interconnection Point** - means a point where the Terasen Gas System interconnects with the facilities of one of the Transporters of Terasen Gas, as specified in a Transportation Agreement.

(p) **Interruptible EKE Receipt Service** - means the interruptible receipt service by which the Shipper provides Gas to Terasen Gas at EKE for firm transportation to a Delivery Point in the Inland Service Area or the Lower Mainland Service Area, as described in section 11.2.

(q) **Month** - means, subject to any changes from time to time required by Terasen Gas, the period beginning at 7:00 a.m. Pacific Standard Time on the first day of the calendar month and ending at 7:00 a.m. Pacific Standard Time on the first day of the next succeeding calendar month.

(r) **Non-Bypass Shipper** - means a Shipper that receives service under Rate Schedule 23, 25 or 22A and pays rates as set out in the standard Table of Charges for the applicable Rate Schedule.

(s) **Pacific Clock Time** - means Pacific Standard Time or Daylight Savings Time as it applies in Surrey, British Columbia.

(t) **Peak Day Demand** - means the quantity of energy used for the purposes of determining the Peaking Gas and EKE Receipt Service available to a Non-Bypass Shipper, as calculated pursuant to section 10.4.

(u) **Peaking Gas** - means Gas which is provided to the Shipper by Terasen Gas in accordance with the provisions of section 10.

(v) **Peaking Gas Quantity** - means the Peaking Gas available to a Non-Bypass Shipper on a Day, determined pursuant to the provisions of section 10.5.

(w) **Rate Schedule 26 or this Rate Schedule** - means this Rate Schedule, including all rates, terms and conditions, and the Table of Charges, as amended from time to time by Terasen Gas with the consent of the British Columbia Utilities Commission.

(x) **Replacement Gas** - means Gas which is provided to a Shipper by Terasen Gas in the event the Shipper fails to return Peaking Gas Quantity pursuant to section 10.7.

(y) **Requested Quantity** - means the quantity of energy for each Day requested for firm transportation under this Rate Schedule.

(z) **Requested Peaking Gas Quantity** - means the quantity of energy for each Day requested as Peaking Gas under this Rate Schedule.

(aa) **Shipper** - means a person who enters into a Transportation Agreement with Terasen Gas who is also the consumer of the Gas transported.

(bb) **Shipper Agent** - means a person who enters into a Shipper Agent Agreement with Terasen Gas.

(cc) **Shipper Agent Agreement** - means an agreement between Terasen Gas and a Shipper Agent pursuant to which the Shipper Agent agrees to act as agent for a Group.

(dd) **Southern Crossing Pipeline** - means the pipeline and other facilities constructed by Terasen Gas from EKE to an interconnection with existing Terasen Gas facilities near Oliver that will enable Terasen Gas to transport Gas between EKE and the Delivery Point.

(ee) **Sumas Daily Price** - means the “NW Sumas” Daily Midpoint Price as set out in Gas Daily’s Daily Price Survey for Gas delivered to Northwest Pipeline Corporation at Sumas, converted to Canadian dollars using the noon exchange rate as quoted by the Bank of Canada, one business day prior to Gas flow date, for each Day. Energy units are converted from MMBtu to Gigajoule by application of a conversion factor equal to 1.055056 Gigajoule per MMBtu.

(ff) **Supplier** - means a party who sells Gas to a Shipper or Terasen Gas or has access to its own supplies of Gas.

(gg) **Table of Charges** - means the table of prices, fees and charges, as amended from time to time by Terasen Gas with the consent of the British Columbia Utilities Commission, appended to this Rate Schedule.

(hh) **Transportation Agreement** - means an agreement between Terasen Gas and a Shipper to provide service pursuant to a transportation Rate Schedule.

(ii) **Transporter** - means, in the case of the Columbia Service Area, TransCanada PipeLines Limited, B.C. System, and in the case of the Inland Service Area and Lower Mainland Service Area, Westcoast Energy Inc., Terasen Huntingdon Inc., TransCanada PipeLines Limited, B.C. System and any other gas pipeline transportation company connected to the facilities of Terasen Gas from which Terasen Gas receives Gas for the purposes of Gas transportation or resale.

(jj) **Transporter's Service Terms** - means the general terms and conditions of the applicable Transporter, as filed with and approved from time to time by the National Energy Board or other applicable governmental authority.

(kk) **Unauthorized Overrun Gas** - means any Gas taken on any Day in excess of the curtailed quantity specified in any notice, to interrupt or curtail a Shipper's take, or to interrupt or curtail a Group's take, and for greater certainty, Unauthorized Overrun Gas includes all Gas taken by a Shipper or a Group to the extent that the obligation of Terasen Gas to deliver such Gas is suspended by reason of Force Majeure.

1.2 **Change in Definition of "Day"** - Terasen Gas may amend the definition of "Day" from time to time to suitably align its operations with those of its Transporters. If Terasen Gas amends the definition of "Day", a pro-rata adjustment of quantities of Gas and charges to account for any Day of more or less than 24 Hours will be made and the term of the Transportation Agreement will be similarly adjusted.

2. Applicability

2.1 **Description of Applicability** - This Rate Schedule is applicable to Shippers with a normalized annual consumption at one Premises of greater than 2,000 Gigajoules of firm Gas. The Gas being shipped under this Rate Schedule must be used in fuel for vehicles.

2.2 **British Columbia Utilities Commission** - This Rate Schedule may be amended from time to time with the consent of the British Columbia Utilities Commission.

3. Conditions of Service

3.1 **Conditions** - Terasen Gas does not provide transportation service as a common carrier. Terasen Gas will only transport Gas under this Rate Schedule to Shippers in the territory served by Terasen Gas under the Terasen Gas tariff of which this Rate Schedule is a part if:

(a) the Shipper has entered into a Transportation Agreement,

(b) adequate capacity exists on the Terasen Gas System, and

(c) Terasen Gas has installed at the Delivery Point the facilities and equipment referred to in section 15.1 (Facilities and Equipment).

3.2 **Security** - In order to secure the prompt and orderly payment of the charges to be paid by the Shipper to Terasen Gas under the Transportation Agreement, Terasen Gas may require the Shipper to provide, and at all times maintain, an irrevocable letter of credit in favour of Terasen Gas issued by a financial institution acceptable to Terasen Gas in an amount equal to the estimated maximum amount payable by the Shipper under this Rate Schedule and the Transportation Agreement for a period of 90 Days. Where Terasen Gas requires a Shipper to provide a letter of credit and the Shipper is able to provide alternative security acceptable to Terasen Gas, Terasen Gas may accept such security in lieu of a letter of credit.

3.3 **Warning if Switching from Interruptible to Firm Transportation Service or Sales** - A Shipper wishing to switch from interruptible transportation or interruptible sales to firm transportation under this Rate Schedule must

(a) give 12 months prior notice to Terasen Gas of the Shipper's desire to do so, and

(b) after receiving an estimate from Terasen Gas of costs Terasen Gas will reasonably incur to provide such service, agree to reimburse Terasen Gas for any such costs.

Notwithstanding section 3.3(a), Terasen Gas will make reasonable efforts to accommodate a Shipper on less than 12 months prior notice if Terasen Gas is able, with such shorter notice, to arrange for firm transportation of Gas under this Rate Schedule.

3.4 **Right to Sell** - Customer will not sell Gas except as fuel for vehicles.

4. Tra nsportation

4.1 **Transportation of Gas** - Subject to section 13 of the General Terms and Conditions of Terasen Gas (Interruption of Service), and all of the terms and conditions of this Rate Schedule, Terasen Gas will on each Day transport for and deliver to the Shipper at the Delivery Point the Authorized Quantity, or the Shipper's portion of the Group's Authorized Quantity, received at the Interconnection Point from the Transporter up to the DTQ. On each Day, if the Shipper's Gas received at the Interconnection Point is not consumed by the Shipper or is not authorized for delivery to the Shipper, Terasen Gas will be entitled to utilize such Gas subject to all the terms of this Rate Schedule and the Transportation Agreement.

4.2 **Curtailment** - Consistent with the provisions of section 7.6 (Failure to Deliver to Interconnection Point), if at any time Terasen Gas, acting reasonably, determines that it is not able to provide Balancing Gas or Backstopping Gas, Terasen Gas may curtail the Shipper's take to the lesser of the Authorized Quantity or the DTQ.

4.3 **Notice of Curtailment** - Each notice from Terasen Gas to the Shipper with respect to the interruption or curtailment by Terasen Gas of deliveries of Gas to the Delivery Point will be by telephone and/or fax and will specify the quantity of Gas to which the Shipper is curtailed and the time at which such curtailment is to be made. Terasen Gas will make reasonable efforts to give the Shipper as much notice as possible with respect to such curtailment, not to be less than 8 Hours prior notice unless prevented by Force Majeure or unless the Transporter does not provide to Terasen Gas at least 8 Hours prior notice of reduced availability of gas.

4.4 **Default Regarding Curtailment** - The Shipper will comply with each notice to interrupt or curtail the Shipper's take. If the Shipper at any time fails or neglects to comply with a notice to interrupt or curtail the Shipper's take as set out in section 7.6 (Failure to Deliver to Interconnection Point), Terasen Gas may, in addition to any other remedy which it may then or thereafter have, at its option, without liability therefor and without any prior notice to the Shipper

(a) turn off the valve at the Delivery Point, or

(b) deliver such Gas and charge the Shipper for such Gas consumed on that Day the unauthorized overrun charge set out in the Table of Charges.

4.5 **Maximum Hourly Quantities** - Terasen Gas will not be obliged to receive or deliver in one Hour more than 5% of the quantity of Gas that the Shipper is authorized to receive on any Day.

4.6 **Gas Pressure** - Where specifically requested by the Shipper, Terasen Gas may agree to deliver Gas to the Shipper at the Delivery Point at a minimum pressure specified in the Shipper's Transportation Agreement. The Shipper will reimburse Terasen Gas for costs it reasonably incurs in maintaining such minimum pressure above that set out in the General Terms and Conditions of Terasen Gas. Terasen Gas' ability to maintain a minimum pressure at the Delivery Point is subject to Terasen Gas receiving Gas at the Interconnection Point at the pressure specified in the Transporter's Service Terms.

5. Ta ble of Charges

5.1 **Charges** - In respect of all quantities of Gas delivered to the Delivery Point pursuant to this Rate Schedule and the Transportation Agreement, the Shipper will pay to Terasen Gas all of the charges set out in the Table of Charges whether or not the Shipper is a member of a Group. The Shipper Agent may elect to pay to Terasen Gas the charges for the Backstopping Gas and the Balancing Gas taken, any Unauthorized Overrun Gas taken, any Replacement Gas incurred, and any Positive Imbalance and Negative Imbalance incurred under Rate Schedule 40 for members of its Group. In the event the Shipper Agent fails to make an election or withdraws an election to pay these charges for and on behalf of the Shippers which are members of its Group, Terasen Gas will bill the Shippers directly.

6. Unaut horized Gas Use

6.1 **Charges for Unauthorized Service** - On any Day a Shipper takes Unauthorized Overrun Gas, the Shipper will pay to Terasen Gas the unauthorized overrun charge set out in the Table of Charges. The Shipper Agent may elect to pay these charges for the members of its Group. In the event the Shipper Agent fails to make an election or withdraws an election to pay these charges for and on behalf of the Shippers which are members of its Group, Terasen Gas will bill the Shippers directly.

6.2 **Payments Not License** - Payments made to Terasen Gas for Unauthorized Overrun Gas neither give the right to take Unauthorized Overrun Gas, nor exclude or limit any other remedies available to Terasen Gas for the Shipper's taking of Unauthorized Overrun Gas.

6.3 **Demand Surcharge** - If the Shipper is a member of a Group which includes a Shipper under Rate Schedules 22, 22A or 22B then the Group and its members will be subject to Demand Surcharges under section 7 (Unauthorized Use) of Rate Schedule 22.

7. Nomination

7.1 **Capacity on Transporter Pipeline(s)** - The Shipper will on or before the Commencement Date notify Terasen Gas of the identity of the party holding capacity for the Shipper on the Transporter pipeline(s), and thereafter from time to time on a prompt basis when such party changes.

7.2 **Requested Quantity** - The Shipper will provide to Terasen Gas by fax or other method approved by Terasen Gas, prior to 7:30 a.m. Pacific Clock Time on each Day (or such other time as may be specified from time to time by Terasen Gas) such information as may be requested by Terasen Gas, which will include, but is not limited to, the Shipper's Requested Quantity for the Day commencing in approximately 24 Hours and the portion of the Requested Quantity to be delivered to Terasen Gas at each applicable Interconnection Point. If the Shipper does not notify Terasen Gas in accordance with the foregoing, then the Shipper's Requested Quantity for the Day commencing in approximately 24 Hours will be deemed to be the Shipper's Requested Quantity, adjusted as set out in section 7.3 (Adjustment of Requested Quantity), for the Day just commencing. The Shipper's Requested Quantity for each Day will equal the Shipper's best estimate, at the time of notification to Terasen Gas of the Requested Quantity, of the quantity of Gas the Shipper will actually consume on such Day.

7.3 **Adjustment of Requested Quantity** - Terasen Gas may adjust, in consultation with the Shipper, the Shipper's Requested Quantity, described in section 7.2 (Requested Quantity), when in the reasonable opinion of Terasen Gas such modification is required in order to minimize the Month end balancing quantity.

7.4 **Request to Transporter** - Terasen Gas will provide to the Transporter(s) the portion of the Shipper's Requested Quantity to be delivered to Terasen Gas at the Interconnection Point with the Transporter, adjusted as set out in section 7.3 (Adjustment of Requested Quantity).

7.5 **Delivery to Interconnection Point** - Each Day the Shipper will cause to be delivered to the applicable Interconnection Point a quantity of Gas at least equal to the portion of the Shipper's Requested Quantity from that Interconnection Point, adjusted as set out in section 7.3 (Adjustment of Requested Quantity).

7.6 **Failure to Deliver to Interconnection Point** - If on any Day the Authorized Quantity from a Transporter is less than the quantity requested from the Transporter pursuant to section 7.4 (Request to Transporter), Terasen Gas may, in its discretion, interrupt or curtail service hereunder to the lesser of such Authorized Quantity or the DTQ. Alternatively, Terasen Gas may deliver additional Gas to the Shipper at the subject Interconnection Point and charge the Shipper the charge for Backstopping Gas as set out in the Table of Charges. If Terasen Gas is unable to ascertain which Shipper's supply has caused a deficiency, Terasen Gas may, in its discretion, interrupt or curtail service to the Shippers on a prorata basis or another basis deemed equitable by Terasen Gas based on available information. Terasen Gas will reallocate the deficiency as soon as reasonable if it obtains information that allows it to determine responsibility and Terasen Gas will disclose to the Shippers how it allocated or reallocated the deficiency.

7.7 **Authorized Quantity** - Terasen Gas will take such action as is reasonable in all the circumstances to advise the Shipper or the Shipper Agent if the portion of the Authorized Quantity from a Transporter is less than the portion of the Requested Quantity to be delivered to Terasen Gas at the Interconnection Point with the Transporter.

7.8 **Determination of DTQ** - The Shipper will provide to Terasen Gas by fax or other method approved by Terasen Gas 30 Days prior to the Commencement Date of each Contract Year the Shipper's DTQ for the following Contract Year. If a Shipper appoints a Shipper Agent to act on its behalf, the Shipper authorizes the Shipper Agent to determine the DTQ set out in the Transportation Agreement, for each Contract Year. This authorization will remain in effect for the term of the Transportation Agreement or so long as the Shipper Agent acts as agent for the Shipper, whichever period is shorter.

8. Gas Balancing

8.1 **Monthly Adjustments** - With the exception of unreturned Peaking Gas, Terasen Gas will make adjustments at the end of each Month for the differences between the sum of the Authorized Quantities and the Shipper's actual consumption as measured daily by Terasen Gas as follows

(a) for overdeliveries (the sum of the Authorized Quantities is greater than the Shipper's actual monthly consumption) Terasen Gas will maintain an inventory account for the Shipper and will increase the balance in the inventory account by the excess amount received. Terasen Gas reserves the right to limit Gas quantities maintained in the Shipper's inventory account and will from time to time in consultation with the Shipper return excess inventory at no charge to the Shipper; this will not relieve the Shipper from its obligation to provide accurate nominations pursuant to section 7.2 (Requested Quantity) , and

(b) except in the case of Backstopping Gas and Unauthorized Overrun Gas, for underdeliveries (the sum of the Authorized Quantities is less than the Shipper's actual Monthly consumption as measured by Terasen Gas), Terasen Gas will sell to the Shipper the deficiency quantities at the Balancing Gas charge set out in the Table of Charges.

8.2 **Imbalance Following Termination** - If Terasen Gas has received a quantity of Gas in excess of the quantity delivered to the Shipper during the term of a Transportation Agreement, then the Shipper may request the excess quantity be returned within 90 Days following termination of the Transportation Agreement.

8.3 **Balancing of Peaking Gas** - Balancing of Peaking Gas is described in section 10.7.

9. Group Nominations and Balancing

9.1 **Group Nomination and Balancing** - If a Shipper appoints a Shipper Agent and becomes a member of a Group and if the Shipper and Shipper Agent have agreed to execute or have executed a Shipper Agent Agreement, and if the members of the Group are in the same Service Area of Terasen Gas and receive service under a transportation Rate Schedule, the Shipper Agent will nominate and balance on behalf of all members of the Group on an aggregate basis pursuant to sections 7 (Nomination), 8 (Gas Balancing), 10 (Peaking Gas) and 11 (EKE Receipt Service) of this Rate Schedule, as modified by this section, and the Shipper Agent will be the agent for each of the members of a Group for the purposes of any and all matters set out in sections 7 (Nomination), 8 (Gas Balancing), 10 (Peaking Gas) and 11 (EKE Receipt Service). Notwithstanding the foregoing, where a Shipper under Rate Schedules 22, 22A or 22B is a member of the Group, section 9 (Gas Balancing) and section 10 (Group Nomination and Balancing) of Rate Schedule 22 will apply to the Group on an aggregate basis. The Shipper Agent may also elect pursuant to the Shipper Agent Agreement, to pay some or all of the charges specified in sections 5.1 and 6.1 for and on behalf of the Shippers in its Group. The Shipper acknowledges and agrees that Terasen Gas may rely, for the purpose of payment allocations, on verbal notification form the Shipper Agent of such election as a basis for the Shipper Agent's authority to act on behalf of Shipper. Where the Shipper Agent fails to execute a Shipper Agent Agreement, the Shipper will be deemed to be and treated by Terasen Gas as an individual Group of one Shipper, except for the purposes of sections 9.5 and 13.1 hereunder, and will be deemed to have agreed to purchase Gas from Terasen Gas pursuant to the applicable transportation schedule and will accordingly be responsible for the payment of all charges thereunder, including any and all Balancing Gas and Unauthorized Overrun Gas charges attributable to that Shipper.

9.2 **Requested Quantity from Shipper Agent** - The Shipper Agent will notify Terasen Gas of the Shipper's Requested Quantity described in section 7.2 (Requested Quantity) on behalf of all members of a Group on an aggregate basis. If the Shipper Agent does not so notify Terasen Gas, then the Group's Requested Quantity for the Day commencing in approximately 24 Hours will be deemed to be the Group's quantity pursuant to section 8.2 (Requested Quantity) for the Day just commencing.

9.3 **Determination of Charges** - The charges for Backstopping Gas, Balancing Gas, Unauthorized Overrun Gas and Replacement Gas set out in the Table of Charges, and Demand Surcharges as set out in the Rate Schedule 22 Table of Charges, will be determined based on the quantities transported on behalf of all members of the Group on an aggregate basis. The charges for Unauthorized Transportation Service will be determined based on the quantities delivered to each Shipper.

9.4 **Security** - Terasen Gas may require the Shipper Agent to provide security, as set out in section 3.2 (Security), with necessary changes, for the performance of the Shipper Agent's obligations under the Shipper Agent Agreement.

9.5 **Notices To and From Shipper Agents** - If the Shipper is a member of a Group then:

(a) communications regarding curtailments or interruptions arising from Gas supply constraints and limitations, quantities of Gas requested and quantities of Gas authorized will be between the Shipper Agent for the Group and Terasen Gas; and

(b) notices from Terasen Gas with respect to interruption or curtailment pursuant to section 4.3 (Notice of Curtailment) arising from Gas supply constraints or limitations will be to the Shipper Agent for the Group and will specify the quantity of Gas to which the Group is curtailed and the time at which such curtailment is to be made; it will be the responsibility of the Shipper Agent to notify Shippers which are members of the Group of interruptions or curtailments.

10. Peaking Gas Service

10.1 **Applicability** - In each Contract Year, Peaking Gas Service is available only to Non-Bypass Shippers for Gas which is delivered to a Delivery Point in the Inland Service Area, Lower Mainland Service Area or Columbia Service Area and for which the Transportation Agreement was in effect on the 1st Day of November of the subject Contract Year.

10.2 **15-Day Maximum** - A Non-Bypass Shipper may request Peaking Gas for a maximum of 15 Days during each Contract Year. Any Day for which any portion of the Shipper's Peaking Gas Quantity is requested and authorized will be considered one of the 15 Days of Peaking Gas entitlement even if the quantity of authorized Peaking Gas is not used or only partially used.

10.3 **Peak Day Demand** - For purposes of determining the Peaking Gas Quantity available to a Non-Bypass Shipper on a Day, the Peak Day Demand of a Rate Schedule 26 Shipper is equal to 1.25 times the Shipper's highest average daily consumption of any month in the winter period from November through March of the preceding Contract Year. In instances respecting which it is agreed by Terasen Gas and Shipper that a Shipper's Gas consumption during the preceding Contract Year is not indicative of prospective consumption, Terasen Gas will set the Peak Day Demand of that Shipper after consultation with that Shipper.

10.4 **Peaking Gas Quantity** - The quantity of Peaking Gas available on a Day to a Non-Bypass Shipper ("Peaking Gas Quantity") will be a percentage of that Shipper's Peak Day Demand. The Peaking Gas Quantity available to Non-Bypass Shippers for the next Contract Year will be determined by Terasen Gas, and Terasen Gas will in writing notify each Non-Bypass Shipper of that Shipper's Peaking Gas Quantity, at least 30 days prior to the commencement of each Contract Year. The Peaking Gas Quantity available to a Non-Bypass Shipper in a Contract Year will be:

(a) $$\frac{\text{Total Non-Bypass Transport Demand}}{\text{Forecast Sales Demand} + \text{Non-Bypass Transport Demand}} = \text{Peaking Gas Factor}$$

(b) Peaking Gas Factor * SCP Peaking Gas = Non-Bypass Transport Volume

(c) $$\frac{\text{Non-Bypass Transport Volume}}{\text{Non-Bypass Transport Demand}} = \text{Peaking Gas Percentage}$$

(d) Peaking Gas Percentage * a Non-Bypass Shipper's Peak Day Demand = Peaking Gas Quantity

Where:

"Non-Bypass Transport Demand" is the aggregate Peak Day Demand of all Non-Bypass Shippers for the Contract Year commencing the next November 1; "Forecast Sales Demand" is the Terasen Gas forecast of the aggregate peak day demand for the Year commencing the next November 1 for all Gas sales Customers of Terasen Gas excluding those in the Fort Nelson Service Area; and "SCP Peaking Gas" is the quantity of peaking gas available to Terasen Gas in the Year commencing the next November 1 due to the operation of the Southern Crossing Pipeline.

10.5 **Requested Peaking Gas Quantity** - Shipper will notify Terasen Gas of its Requested Peaking Gas Quantity pursuant to nomination procedures described in section 7.2 except as otherwise described in section 10.6 (a) and 10.6 (b) below. The Requested Peaking Gas Quantity must be explicitly stated on the nomination and may be less than but may not exceed the Shipper's Peaking Gas Quantity described in section 10.5.

(a) **Prior Day Notices of Curtailment** - On a Day when Terasen Gas has given notice of curtailment for the next or subsequent Day, a Shipper may notify Terasen Gas of its Requested Peaking Gas Quantity for the next Day up until one Hour prior to the evening nomination cycle on the day preceding the Day for which notice of curtailment has been given.

(b) **Same Day Notices of Curtailment** - On a Day when Terasen Gas has given notice of curtailment to be effective during that Day, a Shipper may notify Terasen Gas of its Requested Peaking Gas Quantity up until one Hour after the notice of curtailment has been given by Terasen Gas; provided that Terasen Gas has usable nomination cycles available during that Day with the Transporter(s). Requests for Requested Peaking Gas Quantity received after the time when Terasen Gas has usable nomination cycles available during that Day will be authorized only on an as available basis. If notice of Requested Peaking Gas Quantity is given to Terasen Gas during the Day for which Peaking Gas is being requested then the Peaking Gas Quantity available to Shipper on that Day will be reduced consistent with the elapsed pro-rata practices of applicable Transporter(s).

(c) **Non-Curtailment Days** - On Days for which Terasen Gas has not given notice of curtailment, requests for Peaking Gas Quantity shall be made in accordance with the provisions described in section 7.2.

10.6 **Return of Peaking Gas Quantity** - Terasen Gas will, within 4 business days following the date for which Peaking Gas is authorized, provide to the Shipper a statement indicating the amount of Peaking Gas authorized and used, and this will be the statement used for the purposes of tracking the authorization and use of Peaking Gas. Peaking Gas must be returned to Terasen Gas within 6 Business Days of the Day in respect of which it was authorized. Shipper must notify Terasen Gas that it is returning Peaking Gas Quantity with its nomination for Requested Quantity described in section 7.2. Peaking Gas returned will be applied against the earliest Peaking Gas Quantity authorized and not yet returned. Shipper has option to elect to return Peaking Gas from the Peaking Gas inventory which is kept for this purpose. If Peaking Gas is not returned to Terasen Gas within 6 Business Days, Terasen Gas will provide Shipper with an equivalent quantity of Replacement Gas. The charge for Replacement Gas will be as set out in the Table of Charges.

10.7 **Last Gas Ordered** - Peaking Gas Quantity will be considered the last Gas ordered and taken during the Day.

10.8 **Transport of Peaking Gas Quantity** - Peaking Gas Quantity will be deemed to be provided to the Shipper at the Interconnection Point, and the volumes consumed by the Shipper will be included in the Shipper's monthly transport volume for the purposes of calculating monthly transport charges.

11. Access to East Kootenay Exchange (EKE) Interconnection Point

11.1 Firm EKE Receipt Service

(a) **Applicability** - Firm receipt service access from the EKE Interconnection Point ("Firm EKE Receipt Transport") is available to Non-Bypass Shippers for Gas which is delivered to a Delivery Point in the Inland Service Area and for which the Shipper has a Transportation Agreement which is effective on the August 1st preceding the subject Contract Year ("Inland Non-Bypass Shippers").

(b) **Availability** - The total quantity of Firm EKE Receipt Service available in aggregate to Inland Non-Bypass Shippers ("EKE Transport Volume") will be determined by Terasen Gas for each Contract Year. Terasen Gas shall publish the EKE Transport Volume which is available for the next Contract Year by July 31 of each Year. The EKE Transport Volume shall be determined as follows:

$$\frac{\text{Inland Non-Bypass Transport Demand}}{\text{Forecast Inland Sales Demand} + \text{Inland Non-Bypass Transport Demand}} * \text{ITS Constraint} = \text{EKE Transport Volume}$$

Where:

"Inland Non-Bypass Transport Demand" is the aggregate Peak Day Demand of all Non-Bypass Shippers in the Inland Service Area for the Contract Year commencing the next November 1; "Forecast Inland Sales Demand" is the Terasen Gas forecast of the aggregate peak day demand for the Year commencing the next November 1 for all firm Gas sales Customers of Terasen Gas in the Inland Service Area; and "ITS Constraint" is the capacity of the Terasen Gas Interior transmission system available to flow Gas from Oliver in a northbound direction during periods of peak demand.

(c) **Election** - Annual elections for Firm EKE Receipt Service for the next Contract Year must be submitted in writing by Shippers to Terasen Gas within 5 Business Days of the date on which Terasen Gas publishes the EKE Transport Volume. The election must indicate the quantity of Firm EKE Receipt Service requested. The quantity requested must not exceed the Shipper's Peak Day Demand. Terasen Gas will pro-rate the Firm EKE Receipt Service requests based on the requested quantities if aggregate Firm EKE Receipt Service requests exceed the available EKE Transport Volume. Terasen Gas will notify Shippers of the Shippers' quantity of Firm EKE Receipt Service within 10 Business Days of the date on which Terasen Gas publishes the EKE Transport Volume.

11.2 **Interruptible EKE Receipt Service**

(a) **Applicability** - Interruptible receipt service access to the EKE Interconnection Point ("Interruptible EKE Receipt Service") is available only to Non-Bypass Shippers for which Gas is delivered to a Delivery Point in the Inland Service Area and Lower Mainland Service Area ("Eligible Interruptible Non-Bypass Shippers").

(b) **Quantity Available** - The quantity of Interruptible EKE Receipt Service available to Eligible Interruptible Non-Bypass Shippers will be determined by Terasen Gas. In determining the quantity of Interruptible EKE Receipt Service available Terasen Gas will take into account system delivery constraints including the requirement to flow Gas from the facilities of Westcoast Energy Inc. into the Inland Service Area, and the quantity of Firm EKE Receipt Service not utilized. The quantity of Interruptible EKE Receipt Service available to Eligible Interruptible Non-Bypass Shippers will be a pro-rata portion of the aggregate available demands of all firm Gas sales Customers and all firm transportation Customers in the Inland and Lower Mainland Service Areas.

(c) **Maximum Nomination** - A Shipper may not request Interruptible EKE Receipt Service in excess of the Shipper's Peak Day Demand less the Firm EKE Receipt Service of the Shipper. If Terasen Gas receives requests for Interruptible EKE Receipt Service in excess of the aggregate available Interruptible EKE Receipt Service available for the Day (as determined in 11.2 (b), Terasen Gas will apportion the available Interruptible EKE Receipt Service on a pro-rata basis of requested Interruptible EKE Receipt Service.

(d) **Incremental Costs** - Shippers will be responsible for incremental costs associated with transportation on the facilities of Westcoast Energy Inc. from the Inland Service Area to the Lower Mainland Service Area (if applicable).

12. Term of Transportation Agreement

12.1 **Term** - The initial term of the Transportation Agreement will begin on the Commencement Date and will expire at 7:00 a.m. Pacific Standard Time on the November 1st next following, provided that if the foregoing results in an initial term of less than one year, then the initial term will instead expire at the end of one further Contract Year.

12.2 **Automatic Renewal** - Except as specified in the Transportation Agreement, the term of the Transportation Agreement will continue from year to year after the expiry of the initial term unless cancelled by either Terasen Gas or the Shipper, subject to section 3.3, (Warning if Switching from Interruptible to Firm Transportation Service or Sales) upon not less than 2 months notice prior to the end of the Contract Year then in effect.

12.3 **Early Termination** - The term of the Transportation Agreement is subject to early termination in accordance with section 18 (Default or Bankruptcy).

12.4 **Survival of Covenants** - Upon the termination of the Transportation Agreement, whether pursuant to section 18 (Default or Bankruptcy) or otherwise,

(a) all claims, causes of action or other outstanding obligations remaining or being unfulfilled as at the date of termination, and,

(b) all of the provisions in this Rate Schedule and in the Transportation Agreement relating to the obligation of any of the parties to account to or indemnify the other and to pay to the other any monies owing as at the date of termination in connection with the Transportation Agreement, will survive such termination.

13. Statements and Payments

13.1 **Statements to be Provided** - Terasen Gas will, on or about the 15^{th} day of each month, deliver to the Shipper, a statement for the preceding month showing the Gas quantities delivered to the Shipper and the amount due. If the Shipper is a member of a Group then the statement and the calculation of the amount due from the Shipper will be based on information supplied by the Shipper Agent, or based on other information available to Terasen Gas, as set out in the Shipper Agent Agreement. Terasen Gas will, on or about the 45^{th} day after the end of a Contract Year, deliver to the Shipper a separate statement for the preceding Contract Year showing the amount required from the Shipper in respect of any indemnity due under this Rate Schedule or a Transportation Agreement. Any errors in any statement will be promptly reported to the other party as provided hereunder, and statements will be final and binding unless questioned within one year after the date of the statement.

13.2 **Payment and Late Payment Charge** - Payment for the full amount of the statement, including federal, provincial and municipal taxes or fees applicable thereon, will be made to Terasen Gas at its Vancouver, British Columbia office, or such other place in Canada as it will designate, on or before the 1st business day after the 21st calendar day following the billing date. If the Shipper fails or neglects to make any payment required under this Rate Schedule, or any portion thereof, to Terasen Gas when due, Terasen Gas will include in the next bill to the Shipper a late payment charge of 1.5% per month (19.56% per annum) on the outstanding amount.

13.3 **Examination of Records** - Each of Terasen Gas and the Shipper will have the right to examine at reasonable times the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, charge, computation or demand made pursuant to any provisions of this Rate Schedule or the Transportation Agreement.

14. Quality

14.1 **Minimum Standards** - All Gas delivered to an Interconnection Point by or on behalf of the Shipper and all Gas delivered to the Delivery Point will conform to the quality specifications set out in the applicable Transporter's Service Terms.

15. Me asuring Equipment

15.1 **Facilities and Equipment** - Terasen Gas will, at the cost to the Shipper, install, maintain and operate at the Delivery Point such metering and communications facilities and equipment as Terasen Gas determines are necessary or desirable for measuring the quantity of Gas delivered pursuant to this Rate Schedule to the Shipper and the Shipper will permit Terasen Gas, without cost to Terasen Gas, to use the Shipper's communications lines and power for the purpose of installing, maintaining and operating the measuring equipment of Terasen Gas.

15.2 **Measuring Site** - If Terasen Gas reasonably determines that it is necessary to install the facilities and equipment referred to in section 15.1 (Facilities and Equipment) on the Shipper's property, the Shipper will, without charge, provide a suitable site along with utilities and enclosures for the installation of the facilities and equipment of Terasen Gas. Terasen Gas will at all times have clear access to the site and to all of its facilities and equipment. All facilities and equipment installed by Terasen Gas on the Shipper's property will remain the property of Terasen Gas and may be removed by Terasen Gas upon termination of the Transportation Agreement.

15.3 **Calibration and Test of Measuring Equipment** - The accuracy of the measuring equipment of Terasen Gas will be verified by standard tests and methods at regular intervals and at other times at the initiative of Terasen Gas or upon the reasonable request of the Shipper. Notice of the time and nature of each test conducted in response to communications with or at the request of the Shipper will be given by Terasen Gas to the Shipper sufficiently in advance to permit a representative of the Shipper to be present. If during a test the measuring equipment is found to be registering inaccurately, it will be adjusted at once to read as accurately as possible. The results of each test and adjustment, if any, made by Terasen Gas, whether or not the Shipper is present for such test, will be accepted until the next test. All tests of such measuring equipment of Terasen Gas will be made at the expense of Terasen Gas, except that the Shipper will bear the expense of tests made at its request if the measuring equipment is found to be inaccurate by an amount equal to 2% or less.

15.4 **Inaccuracy Exceeding 2%** - If upon any test the measuring equipment is found to be inaccurate by an amount exceeding 2%, any previous readings of such equipment will be corrected to zero error for any period during which it is definitely known or is agreed upon that the error existed. If the period is not definitely known or is not agreed upon, such correction will be for a period covering the last half of the time elapsed since the date of the last test. Provided that under no circumstances will an adjustment be made for a period of more than the preceding 12 months.

15.5 **Correction of Measuring Errors** - If the measuring equipment is out of service or out of repair so that the quantity of Gas delivered cannot be correctly determined by the reading thereof, the Gas delivered during the period such measuring equipment is out of service or out of repair will be estimated on the basis of the best available data, using the first of the following methods which is feasible

(a) by correcting the error if the percentage of error is ascertained by calibration test or mathematical calculation,

(b) by using the registration of any check measuring equipment if installed and accurately registering, and

(c) by estimating the quantity of Gas delivered to the Shipper during the preceding periods under similar conditions when the meter was registering accurately.

15.6 **Shipper's Equipment** - The Shipper may at its own expense install, maintain and operate its own measuring equipment for the purposes of monitoring or checking the measuring equipment of Terasen Gas, provided that the Shipper will install such equipment so as not to interfere with the operation of the measuring equipment of Terasen Gas.

15.7 **Right to be Present** - Terasen Gas and the Shipper will have the right to inspect all equipment installed or furnished by the other and the charts and other measurement or test data of the other at all times during business hours, and to be present at the time of any installing, testing, cleaning, changing, repairing, calibrating or adjusting done in connection with the measuring equipment of the other party, but all such activities will be performed by the party furnishing the measuring equipment.

15.8 **Preservation of Records** - Both parties will cause to be preserved each test datum, chart and other record of Gas measurement for a period of 2 years.

16. Measurement

16.1 **Unit of Volume** - The unit of volume of Gas for all purposes hereunder will be 1 cubic metre at a temperature of 15^{o} Celsius and an absolute pressure of 101.325 kilopascals.

16.2 **Determination of Volume** - Gas delivered hereunder will be metered using metering apparatus approved by the Standards Division, Industry Canada, Office of Consumer Affairs and the determination of standard volumes delivered hereunder will be in accordance with terms and conditions pursuant to the *Electricity and Gas Inspection Act* of Canada.

16.3 **Conversion to Energy Units** - In accordance with the *Electricity and Gas Inspection Act* of Canada, volumes of Gas delivered each Day will be converted to energy units by multiplying the standard volume by the Heat Content of each unit of Gas. Volumes will be specified in 10^3m^3 rounded to two decimal places and energy will be specified in Gigajoules rounded to one decimal place.

17. Representations, Warranties and Covenants

17.1 **Title** - The Shipper represents and warrants with Terasen Gas that the Shipper will have good title to all Gas to be delivered to Terasen Gas at the Interconnection Point on behalf of the Shipper from Suppliers other than Terasen Gas, free and clear of all liens, encumbrances and claims.

17.2 **Title Not That of Terasen Gas** - Terasen Gas agrees that title to all Gas transported pursuant to the Transportation Agreement remains with the Shipper.

17.3 **Acknowledgement** - The Shipper acknowledges that the Gas transported under the Transportation Agreement will be commingled with Gas within the Terasen Gas System.

18. Default or Bankruptcy

18.1 **Default** - If the Shipper at any time fails or neglects

(a) to make any payment due to Terasen Gas or to any other person under this Rate Schedule or the Transportation Agreement within 30 days after payment is due, or

(b) to correct any default of any of the other terms, covenants, agreements, conditions or obligations imposed upon it under this Rate Schedule or the Transportation Agreement, within 30 days after Terasen Gas gives to the Shipper notice of such default or, in the case of a default that cannot with due diligence be corrected within a period of 30 days, the Shipper fails to proceed promptly after the giving of such notice with due diligence to correct the same and thereafter to prosecute the correcting of such default with all due diligence,

then Terasen Gas may in addition to any other remedy that it has, including the rights of Terasen Gas set out in section 4.4 (Default Regarding Curtailment), and 6 (Unauthorized Gas Use), at its option and without liability therefore

(a) suspend further transportation service to the Shipper and may refuse to deliver Gas to the Shipper until the default has been fully remedied, and no such suspension or refusal will relieve the Shipper from any obligation under this Rate Schedule or the Transportation Agreement, or

(b) terminate the Transportation Agreement, and no such termination of the Transportation Agreement pursuant hereto will exclude the right of Terasen Gas to collect any amount due to it from the Shipper for what would otherwise have been the remainder of the term of the Transportation Agreement.

18.2 **Bankruptcy or Insolvency** - If the Shipper becomes bankrupt or insolvent or commits or suffers an act of bankruptcy or insolvency or a receiver is appointed pursuant to a statute or under a debt instrument or the Shipper seeks protection from the demands of its creditors pursuant to any legislation enacted for that purpose, Terasen Gas will have the right, at its sole discretion, to terminate the Transportation Agreement by giving notice in writing to the Shipper and thereupon Terasen Gas may cease further delivery of Gas to the Shipper and the amount then outstanding for Gas provided under the Transportation Agreement will immediately be due and payable by the Shipper.

19. Notice

19.1 **Notice** - Any notice, request, statement or bill that is required to be given or that may be given under this Rate Schedule or under the Transportation Agreement will, unless otherwise specified, be in writing and will be considered as fully delivered when mailed, personally delivered or sent by fax to the other in accordance with the following:

if to Terasen Gas	TERASEN GAS INC.	
MAILING ADDRESS:	16705 Fraser Highway Surrey, B.C. V4N 0E8	
NOMINATIONS AND FORCE MAJEURE:	Attention: Telephone: Fax:	Marketing Services Representative (604) 592-7788 (604) 592-7892
BILLING AND PAYMENT:	Attention: Telephone: Fax:	Industrial Billing (604) 663-3677 (604) 663-3683
CUSTOMER RELATIONS:	Attention: Telephone: Fax:	Key Account Manager (604) 592-7843 (604) 592-7894

LEGAL AND OTHER:	Attention:	Vice President & General Counsel; Corporate Secretary
	Telephone:	(604) 443-6531
	Fax:	(604) 443-6540

If to the Shipper, then as set out in the Transportation Agreement.

If to the Shipper Agent, then as set out in the Shipper Agent Agreement.

19.2 **Specific Notices** - Notwithstanding section 19.1 (Notice), notices with respect to Force Majeure will be sufficient if:

(a) given by Terasen Gas in writing by fax, or orally in person, or by telephone (to be confirmed in writing) to the person or persons designated from time to time by the Shipper as authorized to receive such notices, or

(b) given by the Shipper by telephone (to be confirmed by fax) in the following manner:

To claim Force Majeure…"Please be advised that (name of company and location of plant) has (reason for claiming Force Majeure as provided in section 21) and hereby claims suspension by reason of Force Majeure in accordance with the terms of Rate Schedule 26 effective 7:00 a.m. Pacific Standard Time (date Force Majeure suspension to become effective, but not to be retroactive)."

To terminate Force Majeure…"Please be advised that (name of company and location of plant) requests a return to normal natural gas service in accordance with Rate Schedule 26 and the Transportation Agreement effective 7:00 a.m. Pacific Standard Time (date of Force Majeure suspension to end, but not to be retroactive) whereby the suspension by reason of Force Majeure currently in force will be terminated."

20. Indemnity and Limitation on Liability

20.1 **Limitation on Liability** - Terasen Gas, its employees, contractors or agents are not responsible or liable for any loss or damages for or on account of any interruption or curtailment of transportation service permitted under the General Terms and Conditions of Terasen Gas, or this Rate Schedule.

20.2 **Indemnity** - The Shipper will indemnify and hold harmless each of Terasen Gas, its employees, contractors and agents from and against any and all adverse claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) arising from or out of each of the following

(a) any defect in title to any Gas delivered to Terasen Gas at the Interconnection Point on behalf of the Shipper from Suppliers other than Terasen Gas, or arising from any charges that are applicable to the Gas delivered to Terasen Gas,

(b) Franchise Fees not otherwise collected by Terasen Gas under the Table of Charges,

(c) nominations made in accordance with sections 7 or 9 of this Rate Schedule by Terasen Gas to the Transporter with respect to the Shipper's transportation volumes, whether or not the Shipper is a member of a Group,

(d) Gas delivered by the Transporter or Shipper to Terasen Gas failing to meet the quality specifications set out in section 14.1 of this Rate Schedule, and

(e) all federal, provincial, municipal taxes (or payments made in lieu thereof) and royalties, whether payable on the delivery of Gas to Terasen Gas by the Shipper or on the delivery of Gas to the Shipper by Terasen Gas, or on any other service provided by Terasen Gas to the Shipper.

20.3 **Principal Obligant** - If the Shipper is a member of a Group, the obligations of each of the Shipper Agent (acting for and on behalf of the Shippers that are members of the Group) and the Shipper (in the event of the failure of the Shipper Agent to make such payments and limited to the charges related to that Shipper) to pay to, or to the order of, Terasen Gas, the charges for Backstopping Gas, Balancing Gas, Replacement Gas, unauthorized overruns set out in the Table of Charges, and Demand Surcharges set out in the Rate Schedule 22 Table of Charges, are those of principal obligant and not of surety and are independent of the respective obligations of the Shipper Agent and the Shipper towards each other pursuant to the Shipper Agent Agreement.

21. For ce Majeure

21.1 **Force Majeure** - Subject to the other provisions of this section 21, if either party is unable or fails by reason of Force Majeure to perform in whole or in part any obligation or covenant set out in this Rate Schedule under which service is rendered or in the Transportation Agreement, the obligations of both Terasen Gas and the Shipper will be suspended to the extent necessary for the period of the Force Majeure condition.

21.2 **Curtailment Notice** - If Terasen Gas claims suspension pursuant to this section 21, Terasen Gas will be deemed to have issued to the Shipper a notice of curtailment.

21.3 **Exceptions** - Neither party will be entitled to the benefit of the provisions of section 21.1 under any of the following circumstances

(a) to the extent that the failure was caused by the negligence or contributory negligence of the party claiming suspension,

(b) to the extent that the failure was caused by the party claiming suspension having failed to diligently attempt to remedy the condition and to resume the performance of the covenants or obligations with reasonable dispatch, or

(c) unless as soon as possible after the happening of the occurrence relied on or as soon as possible after determining that the occurrence was in the nature of Force Majeure and would affect the claiming party's ability to observe or perform any of its covenants or obligations under the Rate Schedule or the Transportation Agreement, the party claiming suspension will have given to the other party notice to the effect that the party is unable by reason of Force Majeure (the nature of which will be specified) to perform the particular covenants or obligations.

21.4 **Notice to Resume** - The party claiming suspension will likewise give notice, as soon as possible after the Force Majeure condition has been remedied, to the effect that it has been remedied and that the party has resumed, or is then in a position to resume, the performance of the covenants or obligations.

21.5 **Settlement of Labour Disputes** - Notwithstanding any of the provisions of this section 21, the settlement of labour disputes or industrial disturbances will be entirely within the discretion of the particular party involved and the party may make settlement of it at the time and on terms and conditions as it may deem to be advisable and no delay in making settlement will deprive the party of the benefit of section 21.1.

21.6 **No Exemption for Payments** - Notwithstanding any of the provisions of this section 21, Force Majeure will not relieve or release either party from its obligations to make payments to the other.

21.7 **Periodic Repair by Terasen Gas** - Terasen Gas may temporarily shut off the delivery of Gas for the purpose of repairing or replacing a portion of the Terasen Gas System or its equipment and Terasen Gas will make reasonable efforts to give the Shipper as much notice as possible with respect to such interruption, not to be less than 8 hours' prior notice except when prevented by Force Majeure. Terasen Gas will make reasonable efforts to schedule repairs or replacements to minimize interruptible or curtailment of transportation service to the Shipper, and to restore service as quickly as possible.

21.8 **Shipper's Gas** - If Terasen Gas curtails or interrupts transportation of Gas by reason of Force Majeure the Shipper will make its supply of Gas available to Terasen Gas, to the extent required by Terasen Gas, to maintain service priority to those customers or classes of customers which Terasen Gas determines should be served. Terasen Gas, in its sole discretion, will either increase the balance in the Shipper's inventory account by the amount taken by Terasen Gas and return an equivalent quantity of Gas to the Shipper as soon as reasonable, or pay the Shipper an amount equal to either Terasen Gas' average Gas cost, or the Shipper's average Gas cost, for the Day(s) during which such Gas was taken, whichever Gas cost the Shipper, in its sole discretion, elects.

21.9 **Alteration of Facilities** - The Shipper will pay to Terasen Gas all reasonable costs associated with the alteration of facilities made at the discretion of Terasen Gas to measure quantities reduced by reason of Force Majeure claimed by the Shipper and to restore such facilities after the Force Majeure condition ends.

22. Disput e Resolution

22.1 **Mediation** - Where any dispute arises out of or in connection with this Rate Schedule or the service provided under it, Terasen Gas and the Shipper agree to try to resolve the dispute by participating in a structured mediation conference with a mediator under the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution.

22.2 **Arbitration** - If Terasen Gas and the Shipper fail to resolve the dispute through mediation, the unresolved dispute shall be referred to, and finally resolved or determined by arbitration under the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution. Unless Terasen Gas and the Shipper agree otherwise the arbitration will be conducted by a single arbitrator.

22.3 **Written Award** - The arbitrator shall issue a written award that sets forth the essential findings and conclusions on which the award is based. The arbitrator will allow discovery as required by law in arbitration proceedings.

22.4 **Failure to Render a Decision** - If the arbitrator fails to render a decision within thirty (30) days following the final hearing of the arbitration, any party to the arbitration may terminate the appointment of the arbitrator and a new arbitrator shall be appointed in accordance with these provisions. If Terasen Gas and the Shipper are unable to agree on an arbitrator or if the appointment of an arbitrator is terminated in the manner provided for above, then either Terasen Gas or the Shipper shall be entitled to apply to a judge of the British Columbia Supreme Court to appoint an arbitrator and the arbitrator so appointed shall proceed to determine the matter mutatis mutandis in accordance with the provisions of this section.

22.5 **Award** - The arbitrator shall have the authority to award

(a) money damages;

(b) interest on unpaid amounts from the date due;

(c) specific performance; and

(d) permanent relief.

22.6 **Costs** - The costs and expenses of the arbitration, but not those incurred by the parties, shall be shared equally, unless the arbitrator determines that a specific party prevailed. In such a case, the non-prevailing party shall pay all costs and expenses of the arbitration, but not those of the prevailing party.

22.7 **Obligations Continue** - The parties will continue to fulfill their respective obligations pursuant to this Rate Schedule and the Transportation Agreement during the resolution of any dispute in accordance with this section 22.

23. Interpretation

23.1 **Interpretation** - Except where the context requires otherwise or except as otherwise expressly provided, in this Rate Schedule or in a Transportation Agreement

(a) all references to a designated section are to the designated section of this Rate Schedule unless otherwise specifically stated,

(b) the singular of any term includes the plural, and vice versa, and the use of any term is equally applicable to any gender and, where applicable, body corporate,

(c) any reference to a corporate entity includes and is also a reference to any corporate entity that is a successor to such entity,

(d) all words, phrases and expressions used in this Rate Schedule or in a Transportation Agreement that have a common usage in the gas industry and that are not defined in the General Terms and Conditions of Terasen Gas, the Definitions or in the Transportation Agreement have the meanings commonly ascribed thereto in the gas industry, and

(e) the headings of the sections set out in this Rate Schedule or in the Transportation Agreement are for convenience of reference only and will not be considered in any interpretation of this Rate Schedule or the Transportation Agreement.

24. Miscellaneous

24.1 **Waiver** - No waiver by either Terasen Gas or the Shipper of any default by the other in the performance of any of the provisions of this Rate Schedule or the Transportation Agreement will operate or be construed as a waiver of any other or future default or defaults, whether of a like or different character.

24.2 **Enurement** - The Transportation Agreement will enure to the benefit of and be binding upon the parties and their respective successors and permitted assigns, including without limitation successors by merger, amalgamation or consolidation.

24.3 **Assignment** - The Shipper will not assign the Transportation Agreement or any of its rights or obligations thereunder without the prior written consent of Terasen Gas which consent will not be unreasonably withheld or delayed. No assignment will release the Shipper from its obligations under this Rate Schedule or under the Transportation Agreement that existed prior to the date on which the assignment takes effect. This provision applies to every proposed assignment by the Shipper.

24.4 **Amendments to be in Writing** - Except as set out in this Rate Schedule, no amendment or variation of the Transportation Agreement will be effective or binding upon the parties unless such amendment or variation is set out in writing and duly executed by the parties.

24.5 **Proper Law** - The Transportation Agreement will be construed and interpreted in accordance with the laws of the Province of British Columbia and the laws of Canada applicable therein.

24.6 **Time is of Essence** - Time is of the essence of this Rate Schedule, the Transportation Agreement and of the terms and conditions thereof.

24.7 **Subject to Legislation** - Notwithstanding any other provision hereof, this Rate Schedule and the Transportation Agreement and the rights and obligations of Terasen Gas and the Shipper under this Rate Schedule and the Transportation Agreement are subject to all present and future laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction over Terasen Gas or the Shipper.

24.8 **Further Assurances** - Each of Terasen Gas and the Shipper will, on demand by the other, execute and deliver or cause to be executed and delivered all such further documents and instruments and do all such further acts and things as the other may reasonably require to evidence, carry out and give full effect to the terms, conditions, intent and meaning of this Rate Schedule and the Transportation Agreement and to assure the completion of the transactions contemplated hereby.

24.9 **Form of Payments** - All payments required to be made under statements and invoices rendered pursuant to this Rate Schedule or the Transportation Agreement will be made by wire transfer to, or cheque or bank cashier's cheque drawn on a Canadian chartered bank or trust company, payable in lawful money of Canada at par in immediately available funds in Vancouver, British Columbia.

Table of Charges

	Lower Mainland Service Area	Inland Service Area	Columbia Service area
1. **Transportation**			
(a) Basic Charge per Month	$ xxx.xx	$ xxx.xx	$ xxx.xx
(b) Delivery Charge per Gigajoule	$ x.xxx	$ x.xxx	$ x.xxx
(c) Administration Charge per Month	$ xx.xx	$ xx.xx	$ xx.xx
2. **Sales**			
(a) Charge per Gigajoule of Balancing Gas supplied	Sumas Daily Price[1] Average for the Month	Sumas Daily Price[1] Average for the Month	Sumas Daily Price[1] Average for the Month
(b) Charges for Backstopping Gas	Sumas Daily Price[1]	Sumas Daily Price[1]	Sumas Daily Price[1]
(c) Replacement Gas[2]	Sumas Daily Price[1] plus 20 Percent	Sumas Daily Price[1] plus 20 Percent	Sumas Daily Price[1] plus 20 Percent
(d) Unauthorized Overrun Charges			
(i) Per Gigajoule on first 5 percent of specified quantity	Sumas Daily Price[1]	Sumas Daily Price[1]	Sumas Daily Price[1]
(ii) Per Gigajoule on all Gas over 5 percent of specified quantity	The greater of $20.00/GJ or 1.5 x the Sumas Daily Price[1]	The greater of $20.00/GJ or 1.5 x the Sumas Daily Price[1]	The greater of $20.00/GJ or 1.5 x the Sumas Daily Price[1]
3. **Rider 3** per Gigajoule	$ (x.xxx)	$ (x.xxx)	$ (x.xxx)
4. **Rider 4** per Gigajoule	$ (x.xxx)	$ (x.xxx)	$ (x.xxx)
5. **Rider 5** per Gigajoule	$ x.xxx	$ x.xxx	$ x.xxx

Rider 1 **Propane Surcharge** - Not applicable.

Rider 2 (Reserved for future use.)

Rider 3 **Earnings Sharing Mechanism** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers for the Year ending December 31, 2010.

Rider 4 **Delivery Rate Refund** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers for the period of April 1, 2009 to December 31, 2010.

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers for the Year ending December 31, 2010.

Franchise Fee Charge of 3.09% of the aggregate of the above charges, is payable (in addition to the above charges) if the facilities to which Gas is delivered under this Rate Schedule are located within the municipal boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which Terasen Gas pays Franchise Fees.

Minimum Charge per month - The minimum charge per month will be the aggregate of the Basic Charge, the transportation administration charge and the Franchise Fee charge.

Special Conditions

Terasen Gas may, in its sole discretion, reduce the Charge per Gigajoule to any Customer where such reduction is necessary to encourage expansion of the NGV market. Any reduction in the Charge will be specified in the Transportation Agreement.

Terasen Gas may make a promotional grant towards the cost to purchase a factory-built NGV vehicle, or the cost to convert a vehicle to natural gas to meet requirements as set by the Government of Canada, provided that such vehicles will obtain Gas from refueling facilities in a Terasen Gas service area. The amount of the grant would not exceed $10 per GJ, based on estimated consumption over a one year period, up to a maximum total grant by vehicle type as listed in the table below:

It is a condition of the grant that the Customer be provided Service under this Rate Schedule.

Factory Built NGV Incentive Grants		
Vehicle Description	GVW (#)	Maximum Grant
Light Duty	< 10,000	$ 2,500
Medium Duty	< 17,000	$ 5,000
Heavy Duty	> 17,000	$ 10,000

The amount of each grant will not exceed the 5-year projected net revenue to Terasen Gas from each corresponding vehicle.

Terasen Gas may also fund Special Demonstration project grants, tied to an individual vehicle purchased by a customer. The amount of the Special Demonstration grant will not exceed the premium cost for the natural gas option for the vehicle. The total funds paid out under the Special Demonstration project grants will not exceed $100,000 in any one year.

Notes:

1. As defined under section 1.1, the Sumas Daily Price quoted each Day will apply to gas consumed on that gas day.

2. The Sumas Daily Price for the sixth Business Day following the Day for which the Peaking Gas was authorized plus 20 percent.

TRANSPORTATION AGREEMENT FOR
RATE SCHEDULES 22, 22A, 22B, 23, 25, 26 AND 27

This Agreement is dated _______________, 20___, between Terasen Gas Inc. ("Terasen Gas") and ____ (the "Shipper").

WHEREAS:

A. Terasen Gas owns and operates the Terasen Gas System; and

B. The Shipper has requested that Terasen Gas arrange for the transportation of Gas on a firm and/or interruptible basis through the Terasen Gas System to ___________________ located in or near ___________________________ British Columbia in accordance with a transportation Rate Schedule as set out below and the terms set out herein.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the terms, conditions and limitations contained herein, the parties agree as follows:

1. Specific Information

Applicable Rate Schedule:	☐ 22 ☐ 22A ☐ 22B ☐ 23 ☐ 25 ☐ 26 ☐ 27
Type of Service:	☐ Firm ☐ Interruptible ☐ Firm and Interruptible
Firm DTQ / DTQ:	_________________ Gigajoules per day
Shipper Agent and / or Group, if applicable:	_____________________________________
Commencement Date:	_____________________________________
Expiry Date:	_____________________________________ (only specify expiry date if term not automatically renewed as set out in the Automatic Renewal section of the applicable transportation Rate Schedule)
Delivery Point:	_____________________________________
Pressure at the Delivery Point:	_____________________________________ (only specify where applicable as set out in the Gas Pressure section of the applicable transportation Rate Schedule)
Service Address:	_____________________________________
Account Number:	_____________________________________

Interconnection Point: The point at (________ km-post ________) where the Transporter's pipeline system in British Columbia interconnection with the Terasen Gas System

Address of Shipper for receiving notices:

______________________ (name of Shipper)	Attention: ______________________
______________________ (address of Shipper)	Telephone: ______________________
______________________	Fax: ______________________
______________________	Email: ______________________
______________________	

The information set out above is hereby approved by the parties and each reference in either this agreement or the applicable transportation Rate Schedule to any such information is to the information set out above.

2. Rate Schedule 22 / 22A / 22B / 23 / 25 / 26 / 27

2.1 **Additional Terms** - All rates, terms and conditions set out in the applicable transportation Rate Schedule (22, 22A, 22B, 23, 25, 26 or 27) and the General Terms and Conditions of Terasen Gas, as any of them may be amended by Terasen Gas and approved from time to time by the British Columbia Utilities Commission, are in addition to the terms and conditions contained in this Transportation Agreement and form part of this Transportation Agreement and bind Terasen Gas and the Shipper as if set out in this Transportation Agreement.

2.2 **Payment of Amounts** - Without limiting the generality of the foregoing, the Shipper will pay to Terasen Gas all of the amounts set out in the applicable transportation Rate Schedule for the services provided under such Rate Schedule and this Transportation Agreement.

2.3 **Conflict** - Where anything in either the applicable transportation Rate Schedule or the General Terms and Conditions of Terasen Gas conflicts with any of the terms and conditions set out in this Transportation Agreement, this Transportation Agreement governs. Where anything in the applicable transportation Rate Schedule conflicts with any of the rates, terms and conditions set out in the General Terms and Conditions of Terasen Gas, the Rate Schedule governs.

2.4 **Member of a Group** - Where the Shipper will be a member of a Group which has a Shipper Agent acting as agent for the members of the Group, Shipper must complete Appendix "A" attached to this Transportation Agreement and Shipper thereby agrees that the terms and conditions of Appendix "A" form part of this Transportation Agreement and bind the Shipper as if set out in this Transportation Agreement.

2.5 **Acknowledgement** - The Shipper acknowledges receiving and reading a copy of the applicable transportation Rate Schedule (22, 22A, 22B, 23, 25, 26 or 27) and the General Terms and Conditions of Terasen Gas and agrees to comply with and be bound by all terms and conditions set out therein. Without limiting the generality of the foregoing, where the transportation service is interruptible, the Shipper acknowledges that it is able to accommodate such interruption or curtailment and releases Terasen Gas from any liability for the Shipper's inability to accommodate such interruption or curtailment of transportation service.

IN WITNESS WHEREOF the parties hereto have executed this Transportation Agreement.

TERASEN GAS INC.	______________________ (here insert name of Shipper)
BY: ______________________ (Signature)	BY: ______________________ (Signature)
______________________ (Title)	______________________ (Title)
______________________ (Name – Please Print)	______________________ (Name – Please Print)
DATE: ______________________	DATE: ______________________

APPENDIX A

NOTICE OF APPOINTMENT OF SHIPPER AGENT

1. ______________________________ (Shipper) hereby gives notice to Terasen Gas that
(Name of Shipper)
Shipper has appointed ____________________________ (the Shipper Agent) to act as
(Name of Shipper Agent)
agent for Shipper in all matters relating to gas supply and to transportation service on the Terasen Gas System. Shipper also gives notice to Terasen Gas that Shipper wishes to be a member of a Group, and the Shipper will cause the Shipper Agent to enter into a Shipper Agent Agreement or other agreement with Terasen Gas that binds the Shipper Agent to pay the charges which the Shipper Agent elects to pay for and on behalf of the Shipper.

2. Shipper acknowledges and agrees that the Shipper Agent will provide aggregate nominations for the Group to Terasen Gas.

3. Shipper acknowledges and agrees that if the Group includes a member which is a Shipper under Rate Schedule 22, 22A, or 22B then section 10 (Group Nominations and Balancing) of Rate Schedule 22 will apply to the Group on an aggregate basis, and the Group and its members will be subject to the Demand Surcharge provisions of Rate Schedule 22.

4. Shipper acknowledges and agrees that when there are constraints or limitations of Gas supply Terasen Gas will notify the Shipper Agent and it will then be the responsibility of the Shipper Agent to notify Shipper of any curtailment or interruption arising from the constraint or limitation of Gas supply.

5. Shipper acknowledges and agrees that the Shipper Agent will provide Gas supply priority schedules to Terasen Gas which will advise Terasen Gas of the allocation of Gas supply amongst members of the Group during constraints or limitations of Gas supply.

6. Shipper acknowledges and agrees that the Shipper Agent will provide Terasen Gas with information which will be used by Terasen Gas to bill Shipper for Backstopping Gas, Balancing Gas, unauthorized overrun charges and Demand Surcharges.

7. Shipper acknowledges that Terasen Gas will bill Shipper on the basis of information provided to Terasen Gas by the Shipper Agent. Shipper agrees that it is bound by the information supplied to Terasen Gas by the Shipper Agent and Shipper agrees that it will not dispute the information provided to Terasen Gas by the Shipper Agent. Shipper agrees that the Shipper Agent may elect to pay some or all of the charges for Gas identified in section 3.8 of the standard form Shipper Agent Agreement and Shipper acknowledges that if the Shipper Agent fails to provide information to Terasen Gas then notwithstanding any election that has been made by the Shipper Agent to pay some or all of the charges for Gas identified in section 3.8 of the standard form Shipper Agent Agreement, Terasen Gas will bill Shipper directly on the bases set out in section 3.9 of the standard form Shipper Agent Agreement of Terasen Gas. Shipper agrees to pay Terasen Gas as billed, and if Shipper disagrees with any of the billing information used by Terasen Gas the Shipper will deal with the Shipper Agent to resolve that disagreement. Disputes between the Shipper and the Shipper Agent shall not constitute a basis for non-payment by Shipper to Terasen Gas of the amounts billed.

8. Shipper will use its best efforts to provide Terasen Gas with at least 30 days notice if Shipper wishes to leave the Group.

9. Shipper acknowledges and agrees that Terasen Gas may disband the Group pursuant to section 10 of the standard form Shipper Agent Agreement.

10. Shipper will indemnify and hold harmless each of Terasen Gas, its employees, contractors and agents from and against any and all adverse claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) arising from any act or omission of the Shipper Agent related to the agency created by the Shipper Agent Agreement.

11. Shipper acknowledges receiving a copy of the standard form Shipper Agent Agreement of Terasen Gas.

____
(here insert name of Shipper)

BY: ______________________________
(Signature)

____
(Title)

____
(Name - Please Print)

DATE: ____________________________

SHIPPER AGENT AGREEMENT

This Agreement is dated _______________, 20___, between Terasen Gas Inc. ("Terasen Gas") and ____ (the "Shipper Agent").

WHEREAS:

1.0 The Shipper Agent wishes to act as agent on behalf of all members of a Group in respect of transportation service on the Terasen Gas System; and

2.0 The Shippers who are members of the Group have entered into Transportation Agreements with Terasen Gas.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the terms, conditions and limitations contained herein, the parties agree as follows:

1. Specific Information

Members of Group:
(if space is insufficient, continue list on an additional page)

Commencement Date of this agreement:

____

Expiry Date of this agreement:

____
(no expiry date need be specified)

Address of Shipper Agent for receiving notices:

____
(name of Shipper Agent)

____
(address of Shipper Agent)

____

____

Attention: _________________________

Telephone: ________________________

Fax: ____________________________

Alternate Tel(s): ____________________

____

The information set out above is hereby approved by the parties and each reference in either this agreement or the applicable Transportation Rate Schedules to any such information is to the information set out above.

2. Definitions

2.1 **Definitions in Rate Schedule 26** - Except where the context requires otherwise or except as otherwise expressly provided in this agreement, all words and phrases defined in Rate Schedule 26 or in the General Terms or Conditions of Terasen Gas have the meanings set out in the Rate Schedule 26 and in the General Terms and Conditions of Terasen Gas.

3. Shipper Agent Obligations

3.1 **Management of Balancing Gas** - The Shipper Agent is responsible for the management of all Balancing Gas for the Group and its members.

3.2 **Management of Backstopping Gas** - The Shipper Agent is responsible for the management of all Backstopping Gas supplied by Terasen Gas to the Group and its members.

3.3 **Management of Peaking Gas Service** - The Shipper Agent is responsible for the management of all Peaking Gas supplied by Terasen Gas to the Group and its members as well as the return of Peaking Gas Quantities and any Replacement Gas.

3.4 **Management of West to East SCP Transportation Service Imbalances** - The Shipper Agent is responsible for the management of Positive Imbalances and Negative Imbalances for West to East SCP Transportation Service under Rate Schedule 40 supplied by Terasen Gas to the Group and its members.

3.5 **Group Nominations and Balancing** - The Shipper Agent will provide Group nomination and balancing to Terasen Gas in accordance with the sections of the applicable transportation Rate Schedules except where a Shipper under Rate Schedules 22, 22A or 22B is a members of the Group, in which case section 9 (Gas Balancing) and section 10 (Group Nomination and Balancing) of Rate Schedule 22 will apply to the Group on an aggregate basis.

3.6 **Standard Gas Supply Priority Schedule (Standard Priority Schedule)** - Before the Commencement Date of this agreement and before the commencement of each Contract Year the Shipper Agent will provide to Terasen Gas a Standard Priority Schedule which will advise Terasen Gas of the priority between members of the Group if a constraint or limitation of Gas supply occurs. The Shipper Agent may provide to Terasen Gas a revised Standard Priority Schedule from time to time and will provide to Terasen Gas a revised Standard Priority Schedule if there is a change in membership of the Group.

3.7 **Gas Supply Constraints or Limitations** - Upon receipt of a notice from Terasen Gas of curtailment or interruptions pursuant to section 4.4 (Notice of Gas Supply Constraint or Limitation) Shipper Agent will determine the allocation of Gas supply between members of the Group and will notify the Shippers which are members of the Group of the curtailment or interruption. Within two hours of receipt of notice from Terasen Gas pursuant to section 4.4, or such longer period as Terasen Gas considers reasonable in the circumstances, the Shipper Agent will provide to Terasen Gas a schedule setting out the Gas supply allocation for the Group to apply during that curtailment or interruption. If the Shipper Agent fails to provide a schedule setting out the Gas supply allocation for the Group to apply during the curtailment or interruption then Terasen Gas will curtail Shippers on the basis set out in the Standard Priority Schedule.

3.8 **Monthly Billing Information** - At the end of each month, and within two business days of Terasen Gas providing to the Shipper Agent a schedule pursuant to section 4.2 (Monthly Provision of Data), the Shipper Agent will provide to Terasen Gas an allocation schedule setting out the daily Gas takes of each member of the Group and identifying for each member of the Group, the Backstopping Gas and the Balancing Gas taken, any Unauthorized Overrun Gas taken, any Replacement Gas incurred, and any Positive Imbalance and Negative Imbalance incurred under Rate Schedule 40. The Shipper Agent will also notify Terasen Gas which charges the Shipper Agent elects to pay on behalf of the members of the Group and, if notice is not received, Terasen Gas will bill the Shippers directly.

3.9 **Lack of Allocation Information** - If, at the end of a month, the Shipper Agent fails to provide to Terasen Gas the monthly allocation schedule pursuant to section 3.8 (Monthly Billing Information) then Terasen Gas will bill on the basis of the best available information. For Balancing Gas Terasen Gas will bill on a basis proportional to the actual takes of the Shippers during the month. For Backstopping Gas Terasen Gas will bill on a basis proportional to the actual Day-to-Day takes of the Shippers during the Days when Backstopping Gas was supplied. For Unauthorized Overrun Gas Terasen Gas will bill on the basis of the schedule(s) setting out the Gas supply allocation for the Group provided to Terasen Gas pursuant to section 3.8, or if the Shipper Agent fails to provide a schedule pursuant to section 3.8, then on the basis of the applicable Standard Priority Schedule provided by the Shipper Agent pursuant to section 3.6. For Replacement Gas Terasen Gas will bill on a basis proportional to actual Day-to-Day takes of the Non-Bypass Shippers during the Day for which the Peaking Gas Quantities were not returned. For Positive Imbalances and Negative Imbalances for West to East SCP Transportation Service Terasen Gas will bill on a basis proportional to the Peak Day Demand of the Non-Bypass Shippers. If further information becomes available, Terasen Gas will adjust the billings on the basis of the further information.

3.10 **Lack of Gas Supply or Nomination** - If the Shipper Agent becomes aware that a Supplier has ceased, or will cease, to supply Gas to a member of the Group; or if the Shipper Agent provides to Terasen Gas a Requested Quantity for the Group which does not include a quantity for a member of the Group, due to a lack of Gas supply to the member of the Group or due to concerns about a possible lack of Gas supply to the member of the Group, then the Shipper Agent will immediately notify Terasen Gas. If the Shipper Agent fails to so notify Terasen Gas then the Shipper Agent is liable to Terasen Gas for the price of any Gas which Terasen Gas delivers to that member of the Group after the time when the Shipper Agent should have provided notice to Terasen Gas.

3.11 **Charges for Extra Services** - If Terasen Gas incurs extra expenses from a Shipper Agent failing to provide information, or failing to provide information in a timely manner, or failing to provide correct information, or otherwise failing to meet its obligations under this agreement, then Terasen Gas may charge the Shipper Agent for such extra expenses and the Shipper Agent agrees to pay Terasen Gas the reasonable extra expenses incurred as a result of such failure.

4. Terasen Gas Obligations

4.1 **Weekly Provision of Data** - Twice a week Terasen Gas will provide to the Shipper Agent a schedule setting out Terasen Gas' best available data on the daily takes of the Group.

4.2 **Monthly Provision of Data** - Within 10 working days after the end of each month Terasen Gas will provide to the Shipper Agent a schedule setting out the daily takes of each member of the Group.

4.3 **Capacity Constraints** - If Terasen Gas, acting reasonably, determines that it does not have capacity on the Terasen Gas System to accommodate interruptible transportation service to any member of the Group then Terasen Gas will directly notify that Shipper pursuant to Notice of Curtailment section of the applicable Rate Schedule and will deal directly with the Shipper if the Shipper takes Unauthorized Overrun Gas or Unauthorized Transportation Service.

4.4 **Notice of Gas Supply Constraint or Limitation** - If Gas supply constraints or limitations occur; either due to a constraint or limitation of supply from Terasen Gas of Backstopping Gas or Balancing Gas, or a constraint or limitation of supply from another Supplier; Terasen Gas will notify the Shipper Agent of any curtailment or interruption, will specify the quantity of Gas to which the Group in aggregate is curtailed and the time at which time such curtailment is to be made. Terasen Gas will make reasonable efforts to give the Shipper Agent as much notice as possible with respect to such curtailment or interruption, not to be less than 4 hours prior notice unless prevented by Force Majeure.

5. Changes to Group

5.1 **Amendments to Group** - Schedule "A" sets out the Shippers who are the members of the Group represented by the Shipper Agent to this agreement. No additions or deletions may be made to the Group without the Shipper Agent providing notice to Terasen Gas of such additions and deletions through provision to Terasen Gas of an amended Schedule "A" showing such additions and deletions and the effective dates of such additions and deletions in accordance with section 5 of this agreement.

5.2 **Deletions From Group** - If the Shipper Agent wishes to cease acting as agent for a Shipper and a Shipper wishes to cease being a member of the Group, upon receipt by Terasen Gas of not less than 30 days prior written notice from both the Shipper and Shipper Agent and provided that the Shipper Agent has provided to Terasen Gas an amended Schedule "A" showing the effective date of deletion of the Shipper from the Group, such Shipper shall be deleted from the Group upon the effective date specified in the amended Schedule "A". A Shipper will be deleted from a Group effective November 1 of a Year if Terasen Gas receives not less than 30 days prior written notice from either the Shipper or Shipper Agent.

5.3 **Additions To Group** - If the Shipper Agent wishes to add a Shipper to a Group and the Shipper wishes to be added to the Group, and the Shipper has entered into a Transportation Agreement and completed an Appendix "A" - Notice of Appointment of Shipper Agent, and both the Shipper and the Shipper Agent have given to Terasen Gas not less than 30 days prior written notice of such addition and provided that the Shipper Agent has provided to Terasen Gas an amended Schedule "A" showing the effective date of the addition of the Shipper to the Group, such Shipper shall be added to the Group upon the effective date specified in Schedule "A".

6. Statements and Payments

6.1 **Statements to be Provided** - If the Shipper Agent elects to pay some or all of the charges for Gas taken by the Shippers as described in section 3.8, Terasen Gas will, on or about the 15th day of each month, deliver to the Shipper Agent a statement for the preceding month showing the Gas quantities, and the applicable charges for which the Shipper Agent is responsible and the amount due. Any errors in any statement will be promptly reported to the other party as provided hereunder, and statements will be final and binding unless questioned within one year after the date of the statement.

6.2 **Payment and Interest** - Payment for the full amount of the statement, including federal, provincial and municipal taxes or fees applicable thereon, will be made to, or to the order of, Terasen Gas at its Surrey, British Columbia office (mailing address: P.O. Box 48230 Bentall Centre, Vancouver, B.C., V7X 1N8), or such other place in Canada as it will designate, on or before the 1st business day after the 10th calendar day following the billing date. If the Shipper Agent or Shipper fails or neglects to make any payment required under this Shipper Agent Agreement, or any portion thereof, to or to the order of Terasen Gas when due, interest on the outstanding amount will accrue, at the rate of interest declared by the chartered bank in Canada principally used by Terasen Gas, for loans in Canadian dollars to its most creditworthy commercial borrowers payable on demand and commonly referred to as its "prime rate", plus

(a) 2% from the date when such payment was due for the first 30 days that such payment remains unpaid and 5% thereafter until the same is paid where the Shipper Agent or Shipper has not, during the immediately preceding 6 month period, failed to make any payment when due hereunder; or

(b) 5% from the date when such payment was due to and including the date the same is paid where the Shipper Agent or Shipper has, during the immediately preceding 6 month period, failed to make any payment when due hereunder.

7. Term

7.1 **Term** - The term of this agreement will commence on the commencement date specified in section 1 of this agreement and will expire either

(a) 30 days following notice from the Shipper Agent that the Shipper Agent wishes to cease to nominate for transportation service and balancing on behalf of the Group, or

(b) the expiry or termination of the Transportation Agreements of all of the members of the Group, or

(c) the expiry date specified in section 1 of this agreement, or

(d) 5 days following notice from Terasen Gas to the Shipper Agent, and to the Shippers which are members of the Group, under section 10.1 (Failure to Provide Information or Default).

whichever date is earlier.

7.2 **Survival of Covenants** - Upon the termination of this agreement,

(a) all claims, causes of action or other outstanding obligations remaining or being unfulfilled as at the date of termination, and,

(b) all of the provisions in this agreement relating to the obligation of either of the parties to provide information to the other in connection with this agreement,

will survive such termination.

8. Representations, Warranties and Covenants

8.1 **Representations and Warranties** - The Shipper Agent represents and warrants to and covenants with Terasen Gas as follows

(a) the members of the Group are listed in section 1 of this agreement,

(b) the Shipper Agent is the agent of each of the members of the Group and has the authority of each of the members of the Group for the purposes of any and all matters set out in the applicable transportation Rate Schedule and this agreement, and

(c) Terasen Gas may rely on any act or thing done, or document executed, by the Shipper Agent in connection with of any and all matters set out in the applicable transportation Rate Schedule and this agreement.

9. Limitation on Liability and Indemnity

9.1 **Limitation on Liability** - Neither Terasen Gas, its employees, contractors or agents will be liable in damages for or on account of any interruption or curtailment of transportation service or Gas supply.

9.2 **Indemnity** - The Shipper Agent will indemnify and hold harmless each of Terasen Gas, its employees, contractors and agents from and against any and all adverse claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) arising from any act or omission of the Shipper Agent related to the agency created by the Shipper Agent Agreement.

10. Disbanding of the Group

10.1 **Failure to Provide Information** - If the Shipper Agent fails to provide Terasen Gas with the information or schedules which the Shipper Agent is required to provide to Terasen Gas pursuant to this agreement or is otherwise in breach of this agreement then, acting reasonably in the circumstances and on 5 days notice to the Shipper Agent and to the members of the Group, Terasen Gas may disband the Group and deal directly with the Shippers which were members of the Group.

10.2 **Default** - If any Shipper which is a member of the Group is in default under the Default or Bankruptcy section of the applicable Rate Schedule or becomes bankrupt or insolvent, then that Shipper will cease to be a member of the Group.

11. Disput e Resolution

11.1 **Mediation** -Where any dispute arises out of or in connection with this Rate Schedule or the service provided under it, Terasen Gas and the Shipper agree to try to resolve the dispute by participating in a structured mediation conference with a mediator under the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution.

11.2 **Arbitration** - If Terasen Gas and the Shipper fail to resolve the dispute through mediation, the unresolved dispute shall be referred to, and finally resolved or determined by arbitration under the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution. Unless Terasen Gas and the Shipper agree otherwise the arbitration will be conducted by a single arbitrator.

11.3 **Written Award** - The arbitrator shall issue a written award that sets forth the essential findings and conclusions on which the award is based. The arbitrator will allow discovery as required by law in arbitration proceedings.

11.4 **Failure to Render a Decision** - If the arbitrator fails to render a decision within thirty (30) days following the final hearing of the arbitration, any party to the arbitration may terminate the appointment of the arbitrator and a new arbitrator shall be appointed in accordance with these provisions. If Terasen Gas and the Shipper are unable to agree on an arbitrator or if the appointment of an arbitrator is terminated in the manner provided for above, then either Terasen Gas or the Shipper shall be entitled to apply to a judge of the British Columbia Supreme Court to appoint an arbitrator and the arbitrator so appointed shall proceed to determine the matter mutatis mutandis in accordance with the provisions of this Section.

11.5 **Award** - The arbitrator shall have the authority to award:

(a) money damages;

(b) interest on unpaid amounts from the date due;

(c) specific performance; and

(d) permanent relief.

11.6 **Costs** - The costs and expenses of the arbitration, but not those incurred by the parties, shall be shared equally, unless the arbitrator determines that a specific party prevailed. In such a case, the non-prevailing party shall pay all costs and expenses of the arbitration, but not those of the prevailing party.

11.7 **Obligations Continue** - The parties will continue to fulfill their respective obligations pursuant to this Rate Schedule and the Transportation Agreement during the resolution of any dispute in accordance with this section 22.

12. Notice

12.1 **Notice** - Any notice, request, statement or bill that is required to be given or that may be given under this agreement will, unless otherwise specified, be in writing and will be considered as fully delivered when mailed, personally delivered or sent by fax to the other party.

13. Acknowl edgement

13.1 **Acknowledgement** - The Shipper Agent acknowledges receiving and reading a copy of Rate Schedules 22, 22A, 22B, 23, 25, 26 or 27 and the General Terms and Conditions of Terasen Gas and will comply with and be bound by all terms and conditions set out therein.

IN WITNESS WHEREOF the parties hereto have executed this agreement.

TERASEN GAS INC.	______________________________ (here insert name of Shipper Agent)
BY: ______________________________ (Signature)	BY: ______________________________ (Signature)
______________________________ (Title)	______________________________ (Title)
______________________________ (Name – Please Print)	______________________________ (Name – Please Print)
DATE: ______________________________	DATE: ______________________________

TERASEN GAS INC.

RATE SCHEDULE 6A

O

Pages R-6A i to R-6A.5 are cancelled and reserved for future use.

TERASEN GAS INC.

RATE SCHEDULE 6A

~~**GENERAL SERVICE – VEHICLE REFUELLING SERVICE**~~

Pages R-6A i to R-6A.5 are cancelled and reserved for future use.

TERASEN GAS INC.

RATE SCHEDULE 6C
COMPRESSION and REFUELING SERVICE

Effective: January 1, 2010

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Section **Page**

1. Applicability

1.1 **Description of Applicability** - This Rate Schedule applies to the sale of Compression and Refueling services to operate natural gas vehicles.

1.2 **Service Agreement** - Terasen Gas will only sell Compression and Refueling Services pursuant to an executed Service Agreement which may be amended from time to time with the consent of the British Columbia Utilities Commission.

1.3 **British Columbia Utilities Commission** - This Rate Schedule may be amended from time to time with the consent of the British Columbia Utilities Commission.

2. Conditions of Service

2.1 **Conditions** - This Rate Schedule is available in all territory served by Terasen Gas under the tariff of which this Rate Schedule is a part if the Customer has entered into a service agreement with Terasen Gas to purchase Gas under another Rate Schedule.

2.2 **Security** - In order to secure the prompt and orderly payment of the charges to be paid by the Customer to Terasen Gas under the Service Agreement Terasen Gas may require the Customer to provide, and at all times maintain, an irrevocable letter of credit in favour of Terasen Gas issued by a financial institution acceptable to Terasen Gas in an amount equal to the maximum amount payable by the Customer under this Rate Schedule and the Service Agreement for a period of 90 days. Where Terasen Gas requires a Customer to provide a letter of credit and the Customer is able to provide alternative security acceptable to Terasen Gas, Terasen Gas may accept such security in lieu of a letter of credit.

3. Ec onomic Test

3.1 **Economic Test** - All applications for Compression and Refueling Service will be subject to an economic test approved by the British Columbia Utilities Commission. The economic test will be a discounted cash flow analysis of the projected revenue and costs associated with the Compression and Refueling Service. The Compression and Refueling Service will be deemed to be economic and will be supplied if the results of the economic test indicate a Profitability Index of 1.0 or greater for an individual Compression and Refueling Service.

3.2 **Revenue** - The projected revenue to be used in the economic test will be determined by Terasen Gas by establishing consumption estimate for each Customer over the Term.

3.3 **Costs** - The total costs to be used in the economic test include, without limitation:

(a) the full labour, material, and other costs necessary to provide Compression and Refueling Service;

(b) the incremental operating and maintenance expenses necessary to provide Compression and Refueling Service; and

(c) the appropriate allocation of Terasen Gas' overheads.

In addition to the costs identified, the economic test will include applicable taxes and the appropriate return on investment as approved by the British Columbia Utilities Commission.

3.4 **Contributions in Aid of Installation** - If the economic test results indicate a Profitability Index of less than 1.0, the Compression and Refueling Service may proceed provided that the shortfall in revenue is eliminated by contributions in aid of installation by the Customer.

Terasen Gas may finance the contributions in aid of installation for Customers. Contributions of less than $100 per Customer may be waived by Terasen Gas.

3.5 **Contributions Paid by the Customer** - The total required contribution will be paid by the Customer utilizing the Compression and Refueling Service. Terasen Gas will collect a contribution from the Customer prior to service.

4. Compression and Refueling Services

4.1 **Compression and Refueling Service** - Terasen Gas will provide such Compression and Refueling Service as it, in its sole discretion, believes will meet the anticipated load of the Customer, based on information provided by the Customer to it.

4.2 **Substitution of Services** - Terasen Gas reserves the right to substitute any or all of the Compression and Refueling Services at its sole discretion at any time during the term of this Service Agreement.

4.3 **Installation** - Terasen Gas will be responsible for the purchase, delivery, off-loading, hook-up and commissioning of the Compression and Refueling Equipment. Upon the expiration or earlier termination of this Service Agreement for any reason, Terasen Gas will, in consultation with the Customer, commence removal of its facilities and equipment from the Premises and will complete such removal within 90 days of such commencement. Upon the removal of the equipment at the expiration or earlier termination of this Service Agreement, Terasen Gas will return the Premises, to the extent that is reasonably possible, to their condition prior to the installation of the equipment, with the exception that all underground constructions such as foundations, piping, electrical conduits and cables may be left in place at the discretion of Terasen Gas.

4.4 **Ownership** - Terasen Gas will retain ownership of the Compression and Refueling Equipment whether or not such equipment is affixed to the land on which it is located. The Customer shall have no right, title or interest in the Compression and Refueling Equipment other than the right to operate and use the Compression and Refueling Equipment in accordance with section 4.5 of this Service Agreement. The Customer agrees to grant Terasen Gas, in a form acceptable to Terasen Gas and upon Terasen Gas' request, a statutory right of way over the land over which the equipment is located giving Terasen Gas the right to install and maintain the Compression and Refueling Equipment on the land. The Customer will not, without the prior written consent of Terasen Gas, remove the Compression and Refueling Equipment from the Premises.

4.5 **Operations** - The Customer will dispense NGV from the Compression and Refueling Equipment and agrees to abide by the dispensing operating instructions provided by Terasen Gas, as amended from time to time. The Customer will also provide suitable protection and security for the Compression and Refueling Equipment, satisfactory to Terasen Gas.

4.6 **Electrical Energy** - The Customer agrees to provide, at its own expense, the electrical energy required to operate the Compression and Refueling Equipment. The Customer is responsible for providing back up emergency power service if it deems such to be necessary.

4.7 **Maintenance** - Terasen Gas will maintain the Compression and Refueling Equipment in good working order during the term of this Service Agreement. The cost of providing this maintenance is included as part of the service charge specified in section 5.1. Terasen Gas undertakes to provide maintenance for the Compression and Refueling Equipment on a commercially reasonable efforts basis and will not be liable or responsible for any loss or damage arising from delay or loss of service hereunder. Terasen Gas will, upon reasonable notice, have clear access to the Premises and to all of its Compression and Refueling Equipment.

4.8 **Damage** - The Customer is responsible for damage to or abuse of the Compression and Refueling Equipment including but not limited to hoses, nozzle, dispenser, and drive-aways (vehicle drive-aways with the nozzle still connected that damage the equipment). Terasen Gas will repair the damage and charge all costs back to the Customer.

5. Ta ble of Charges

5.1 **Charges** - In respect of the Compression and Refueling Service provided by Terasen Gas to the Customer under this Rate Schedule and the Service Agreement, the Customer will pay to Terasen Gas all of the charges set out in the Table of Charges.

5.2 **Payment on Termination** - Upon expiration of the Service Agreement at the end of the term or upon early termination by Terasen Gas, the Customer shall immediately pay to Terasen Gas any difference between the Gas consumption estimate for such Customer used in the calculation of the economic test and the actual Gas consumption of such Customer until the date of termination multiplied by the compression charge per Gigajoule set out in the Table of Charges.

6. Term of Service Agreement

6.1 **Term** - The initial term of a Service Agreement for Compression and Refueling Service will begin on the Commencement Date and will expire at 7:00 a.m. Pacific Standard Time five years from the Commencement Date.

6.2 **Automatic Renewal** - Except as specified in the Service Agreement, the term of the Service Agreement will continue on a year to year basis until cancelled by either Terasen Gas or the Customer upon not less than 6 Months notice prior to the end of the term then in effect.

6.3 **Early Termination** - The term of the Service Agreement is subject to early termination in accordance with section 8 (Default or Bankruptcy).

6.4 **Survival of Covenants** - Upon the termination of the Service Agreement, whether pursuant to section 8 (Default or Bankruptcy) or otherwise,

(a) all claims, causes of action or other outstanding obligations remaining or being unfulfilled as at the date of termination, and

(b) all of the provisions in this Rate Schedule and in the Service Agreement relating to the obligation of any of the parties to account to or indemnify the other and to pay to the other any monies owing as at the date of termination in connection with the Service Agreement,

will survive such termination.

7. Statement and Payments

7.1 **Statements to be Provided** - Terasen Gas will, each month, deliver to the Customer a statement for the preceding month showing the payment due. Any errors in any statement will be promptly reported to the other party as provided hereunder, and statements will be final and binding unless questioned within one year after the date of the statement.

7.2 **Payment and Late Payment Charge** - Payment for the full amount of the statement, including federal, provincial and municipal taxes or fees applicable thereon, will be made to Terasen Gas at its Vancouver, British Columbia office, or such other place in Canada as it will designate, on or before the 1st business day after the 21st calendar day following the billing date. If the Customer fails or neglects to make any payment required under this Rate Schedule, or any portion thereof, to Terasen Gas when due, Terasen Gas may include in the next bill to the Customer a late payment charge in accordance with Terasen Gas' standard fees and charges.

8. Default or Bankruptcy

8.1 **Default** - If the Customer at any time fails or neglects

(a) to make any payment due to Terasen Gas or to any other person under this Rate Schedule or the Service Agreement within 30 days after payment is due, or

(b) to cure any default of any of the other terms, covenants, agreements, conditions or obligations imposed upon it under this Rate Schedule or the Service Agreement, within 30 Days after Terasen Gas gives to the Customer notice of such default or, in the case of a default that cannot with due diligence be cured within a period of 30 Days, the Customer fails to proceed promptly after the giving of such notice with due diligence to cure the same and thereafter to prosecute the curing of such default with all due diligence,

then Terasen Gas may in addition to any other remedy that it has, at its option and without liability therefore

(a) suspend further service to the Customer, including lock off or removal of the Compression and Refueling Equipment until the default has been fully remedied, and no such suspension or refusal will relieve the Customer from any obligation under this Rate Schedule or the Service Agreement; or

(b) terminate the Service Agreement, and no such termination of the Service Agreement pursuant hereto will exclude the right of Terasen Gas to collect any amount due to it from the Customer for what would otherwise have been the remainder of the term of the Service Agreement.

8.2 **Bankruptcy or Insolvency** - If the Customer becomes bankrupt or insolvent or commits or suffers an act of bankruptcy or insolvency or a receiver is appointed pursuant to a statute or under a debt instrument or the Customer seeks protection from the demands of its creditors pursuant to any legislation enacted for that purpose, Terasen Gas will have the right, at its sole discretion, to terminate the Service Agreement by giving notice in writing to the Customer and thereupon Terasen Gas may cease further delivery of Gas to the Customer and the amount then outstanding for Gas provided under the Service Agreement will immediately be due and payable by the Customer.

9. No tice

9.1 **Notice** - Any notice, request, statement or bill that is required to be given or that may be given under this Rate Schedule or under the Service Agreement will, unless otherwise specified, be in writing and will be considered as fully delivered when mailed, personally delivered or sent by fax to the other in accordance with the following:

<u>if to Terasen Gas</u>	TERASEN GAS INC.	
MAILING ADDRESS:	16705 Fraser Highway Surrey, B.C. V4N 0E8	
BILLING AND PAYMENT:	Attention: Telephone: Fax:	Industrial Billing (604) 663-3677 (604) 663-3683
CUSTOMER RELATIONS:	Attention: Telephone: Fax:	Commercial Industrial Account Manager (604) 592-7843 (604) 592-7894

<u>If to the Customer</u>, then as set out in the Service Agreement.

9.2 **Specific Notices** - Notwithstanding section 9.1 (Notice), notices with respect to suspension of Compression and Refueling Services by Terasen Gas for reasons of Force Majeure will be sufficient if given by Terasen Gas in accordance with section 13.3 of the General Terms and Conditions.

10. Insurance

10.1 **Insurance for Compression and Refueling Equipment** - The Customer shall carry and maintain in force during the term of the Service Agreement primary all risks insurance coverage (including coverage for the rupture of any pressure vessel, electrical arcing and mechanical failure) for loss of or damage to the Compression and Refueling Equipment in an amount not less than the full replacement value of the Compression and Refueling Equipment. The policy will include a requirement that the insurer provide Terasen Gas with 30 days written notice prior to the effective date of any cancellation or material change to the insurance. Such insurance will name Terasen Gas as an additional named insured with respect to the loss of or damage to the Compression and Refueling Equipment. Such insurance will be primary coverage with respect to all insureds.

10.2 **Third Party Liability Insurance** - The Customer shall carry and maintain in force during the term of this Service Agreement separate commercial general liability (bodily injury and property damage) insurance policies with a limit not less than $5,000.00. The policy shall include a Sudden and Accidental Pollution Endorsement and a requirement that the insurer provide Terasen Gas with 30 days written notice prior to the effective date of any cancellation or material change to the insurance.

10.3 **Certificate of Insurance** - Upon the reasonable request of Terasen Gas, the Customer shall provide a certificate of insurance evidencing the existence of the insurance policies to be maintained by the Customer under sections 10.1 and 10.2.

11. Indemnities

11.1 **Indemnity** - Customer will indemnify, defend and hold harmless each of Terasen Gas, its directors, officers, shareholders, employees, contractors, agents, successors and permitted assigns from and against any and all liability, adverse claims, losses, suits, actions, judgments, demands, debt accounts, damages, costs, penalties and expense of every kind and nature for

(a) injury to or death of any and all persons;

(b) damage, destruction or loss, consequential or otherwise, to or of any and all property, real or personal resulting directly or indirectly from the Compression and Refueling Services supplied by Terasen Gas to the Customer and caused by negligent or intentional acts or omissions of the Customer;

(c) any breach of or non compliance with the representations contained in section 13 by the Customer; and

(d) connected with the presence, any release or alleged release of any Contaminants at or from the Premises unless and only to the extent that the Property is determined to be a contaminated site as a result of the activities of Terasen Gas, its employees, agents, successors or permitted assigns.

11.2 **Survival** - The indemnity specified in section11.1 will survive the termination of this Service Agreement.

12. For ce Majeure

12.1 **Force Majeure** - Subject to the other provisions of this section 12, if either party is unable or fails by reason of Force Majeure to perform in whole or in part any obligation or covenant set out in this Service Agreement, the obligations of both Terasen Gas and the Customer will be suspended to the extent necessary for the period of the Force Majeure condition.

12.2 **Exceptions** - Neither party will be entitled to the benefit of the provisions of section 12.1 of this Service Agreement under any of the following circumstances:

(a) to the extent that the failure was caused by the negligence or contributory negligence of the party claiming suspension;

(b) to the extent that the failure was caused by the party claiming suspension having failed to diligently attempt to remedy the condition and to resume the performance of the covenants or obligations with reasonable dispatch; or

(c) unless as soon as possible after the happening of the occurrence relied on or as soon as possible after determining that the occurrence was in the nature of Force Majeure and would affect the claiming party's ability to observe or perform any of its covenants or obligations under this Service Agreement , the party claiming suspension will have given to the other party notice to the effect that the party is unable by reason of Force Majeure (the nature of which will be specified) to perform the particular covenants or obligations.

12.3 **Notice to Resume** - The party claiming suspension will likewise give notice, as soon as possible after the Force Majeure conditions has been remedied, to the effect that it has been remedied and that the party has resumed, or is then in a position to resume, the performance of the covenants or obligations.

12.4 **Settlement of Labour Disputes** - Notwithstanding any of the provisions of this section 12, the settlement of labour disputes or industrial disturbances will be entirely within the discretion of the particular party involved and the party may make settlement of it at the time and on terms and conditions as it may deem to be advisable and no delay in making settlement will deprive the party of the benefit of section 12.1 of this Service Agreement.

12.5 **No Exemption for Payments** - Notwithstanding any of the provisions of this section12, Force Majeure will not relieve or release either party from its obligations to make payments to the other.

12.6 **Periodic Repair by Terasen Gas** - Terasen Gas may temporarily shut off the delivery of Gas or NGV for the purpose of repairing or replacing a portion of the Compression and Refueling Equipment and Terasen Gas will endeavor to give the Customer as much notice as possible with respect to such interruption, not to be less than 8 hours prior notice except when prevented by Force Majeure or in the case of emergency repairs.

13. Environmental Representations

13.1 **Customer's Representations and Warranties** - The Customer represents and warrants to Terasen Gas that as of the date of this Service Agreement the Premises are free of Contaminants, except in amounts which are permissible under Environmental Laws.

13.2 **Customer's Covenants** - The Customer covenants and agrees as follows

(a) not to use or permit the Premises to be used for the sale, storage, manufacture, disposal, handling, treatment, use or any other dealing with any Contaminants, except in compliance with Environmental Laws; and

(b) to comply with Environmental Laws in respect to the Premises.

14. Disputes

14.1 **Mediation** - Where any dispute arises out of or in connection with the Compression and Refueling Service, Terasen Gas and the Customer agree to try to resolve the dispute by participating in a structured mediation conference with a mediator under the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution.

14.2 **Arbitration** - If Terasen Gas and the Customer fail to resolve the dispute through mediation, the unresolved dispute shall be referred to, and finally resolved or determined by arbitration under the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution. Unless Terasen Gas and the Customer agree otherwise the arbitration will be conducted by a single arbitrator.

14.3 **Written Award** - The arbitrator shall issue a written award that sets forth the essential findings and conclusions on which the award is based. The arbitrator will allow discovery as required by law in arbitration proceedings.

14.4 **Failure to Render a Decision** - If the arbitrator fails to render a decision within thirty (30) days following the final hearing of the arbitration, any party to the arbitration may terminate the appointment of the arbitrator and a new arbitrator shall be appointed in accordance with these provisions. If Terasen Gas and the Customer are unable to agree on an arbitrator or if the appointment of an arbitrator is terminated in the manner provided for above, then either Terasen Gas or the Customer shall be entitled to apply to a judge of the British Columbia Supreme Court to appoint an arbitrator and the arbitrator so appointed shall proceed to determine the matter mutatis mutandis in accordance with the provisions of this section.

14.5 **Award** - The arbitrator shall have the authority to award

(a) money damages;

(b) interest on unpaid amounts from the date due;

(c) specific performance; and

(d) permanent relief.

14.6 **Costs** - The costs and expenses of the arbitration, but not those incurred by the parties, shall be shared equally, unless the arbitrator determines that a specific party prevailed. In such a case, the non-prevailing party shall pay all costs and expenses of the arbitration, but not those of the prevailing party.

14.7 **Obligations Continue** - The parties will continue to fulfill their respective obligations pursuant to this Rate Schedule 6C and the Service Agreement during the resolution of any dispute in accordance with this section 14.

15. Interpretation

15.1 **Definitions in General Terms and Conditions of Terasen Gas** - Except where the context requires otherwise or except as otherwise expressly provided in this Rate Schedule, all words and phrases defined in the General Terms and Conditions and used in this Rate Schedule or in a Service Agreement have the meanings set out in the General Terms and Conditions.

15.2 **Further Definitions** - Additionally, except where the context requires otherwise, each of the words and phrases described in the Definitions have the meanings as set out in the Definitions.

15.3 **Interpretation** - Except where the context requires otherwise or except as otherwise expressly provided, in this Rate Schedule or in a Service Agreement

(a) all references to a designated section are to the designated section of this Rate Schedule unless otherwise specifically stated;

(b) the singular of any term includes the plural, and vice versa, and the use of any term is equally applicable to any gender and, where applicable, body corporate;

(c) any reference to a corporate entity includes and is also a reference to any corporate entity that is a successor to such entity;

(d) all words, phrases and expressions used in this Rate Schedule or in a Service Agreement that have a common usage in the gas industry and that are not defined in the General Terms and Conditions of Terasen Gas, the Definitions or in the Service Agreement have the meanings commonly ascribed thereto in the gas industry; and

(e) the headings of the sections set out in this Rate Schedule or in the Service Agreement are for convenience of reference only and will not be considered in any interpretation of this Rate Schedule or the Service Agreement.

16. Miscellaneous

16.1 **Waiver** - No waiver by either Terasen Gas or the Customer of any default by the other in the performance of any of the provisions of this Rate Schedule or the Service Agreement will operate or be construed as a waiver of any other or future default or defaults, whether of a like or different character.

16.2 **Enurement** - The Service Agreement will enure to the benefit and be binding upon the parties and their respective successors and permitted assigns, including without limitation successors by merger, amalgamation or consolidation.

16.3 **Assignment** - The Customer will not assign the Service Agreement or any of its rights or obligations thereunder without the prior written consent of Terasen Gas which consent will not be unreasonably withheld or delayed. No assignment will release the Customer from its obligations under this Rate Schedule or under the Service Agreement that existed prior to the date on which the assignment takes effect. This provision applies to every proposed assignment by the Customer.

16.4 **Amendments to be in Writing** - Except as set out in this Rate Schedule, no amendment or variation of the Service Agreement will be effective or binding upon the parties unless such amendment or variation is set forth in writing and duly executed by the parties.

16.5 **Proper Law** - The Service Agreement will be construed and interpreted in accordance with the laws of the Province of British Columbia and the laws of Canada applicable therein.

16.6 **Time is of Essence** - Time is of the essence of this Rate Schedule, the Service Agreement and of the terms and conditions thereof.

16.7 **Subject to Legislation** - Notwithstanding any other provision hereof, this Rate Schedule and the Service Agreement and the rights and obligations of Terasen Gas and the Customer under this Rate Schedule and the Service Agreement are subject to all present and future laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction over Terasen Gas or the Customer.

16.8 **Further Assurances** - Each of Terasen Gas and the Customer will, on demand by the other, execute and deliver or cause to be executed and delivered all such further documents and instruments and do all such further acts and things as the other may reasonably require to evidence, carry out and give full effect to the terms, conditions, intent and meaning of this Rate Schedule and the Service Agreement and to assure the completion of the transactions contemplated hereby.

16.9 **Form of Payments** - All payments required to be made under statements and invoices rendered pursuant to this Rate Schedule or the Service Agreement will be made by telegraphic transfer to, or cheque or bank cashier's cheque drawn on, a Canadian chartered bank or trust company, payable in lawful money of Canada at par in immediately available funds in Vancouver, British Columbia.

Definitions

(a) **Commencement Date** - means the Day specified as the Commencement Date in the Service Agreement.

(b) **Compression and Refueling Equipment** - means the compressors, storage and dispensers installed by Terasen Gas on the Customer's Premises and as may be substituted from time to time at the sole discretion of Terasen Gas, together with such other ancillary parts, additions, and equipment as may be necessary to put the compressors, storage and dispensers into operation.

(c) **Consumption Units** - means the total number of units of NGV, expressed in Gigajoules consumed from time to time by the Compression and Refueling Equipment according to the Terasen Gas' records.

(d) **Contaminants** - means any radioactive materials, asbestos materials, urea formaldehyde, underground or aboveground tanks, pollutants, contaminants, deleterious substances, dangerous substances or goods, hazardous, corrosive or toxic substances, special waste or waste of any kind or any other substance the storage, manufacture, disposal, handling, treatment, generation, use, transport, remediation or release into the environment of which is now or hereafter prohibited, controlled or regulated under Environmental Laws.

(e) **Customer** - means a person who enters into a Service Agreement with Terasen Gas.

(f) **Environmental Laws** - means any and all statutes, laws, regulations, orders, bylaws, standards, guidelines, permits and other lawful requirements of any federal, provincial, municipal or other governmental authority having jurisdiction over the Premises now or hereafter in force with respect in any way to the environment, health, occupational health and safety, product liability or transportation of dangerous goods, including the principles of common law and equity.

(g) **Force Majeure** - means any acts of God, strikes, lockouts, or other industrial disturbances, civil disturbances, arrests and restraints of rulers or people, interruptions by government or court orders, present or future valid orders of any regulatory body having proper jurisdiction, acts of the public enemy, wars, riots, blackouts, insurrections, failure or inability to secure materials or labour by reason of priority, regulations or orders of government, serious epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, explosions, breakage or accident to the Compression and Refueling Equipment, which act of Force Majeure was not due to negligence of the party claiming Force Majeure.

(h) **General Terms and Conditions** - means the general terms and conditions of Terasen Gas from time to time approved by the British Columbia Utilities Commission.

(i) **NGV** - means natural gas for vehicles.

(j) **Rate Schedule 6C or this Rate Schedule** - means this Rate Schedule, including all rates, terms and conditions, Definitions and the Table of Charges, as amended from time to time by Terasen Gas with the consent of the British Columbia Utilities Commission.

(k) **Service Agreement** - means an agreement between Terasen Gas and a Customer to provide service pursuant to this Rate Schedule.

(l) **Table of Charges** - means the table of prices, fees and charges, as amended from time to time by Terasen Gas with the consent of the British Columbia Utilities Commission, appended to this Rate Schedule.

Table of Charges

Compression Charge per Gigajoule	**$ 5.00/GJ**

AGREEMENT FOR COMPRESSION AND REFUELING SERVICES FOR NATURAL GAS VEHICLES

This Service Agreement for Compression and Refueling Services for Natural Gas Vehicles ("Service Agreement") dated the ____ day of _____________, 20___ ("Commencement Date") between Terasen Gas Inc. ("Terasen Gas") and _____________________________ (the "Customer").

WHEREAS:

A. Terasen Gas has entered into a Service Agreement with the Customer under Rate Schedule 6 or Rate Schedule 26 to provide the Customer with natural gas;

B. Terasen Gas wishes to provide the Customer with natural gas Compression and Refueling Services under Rate Schedule 6C at _________________________________ [location] (the "Premises") in the Province of British Columbia, from which the Customer desires to dispense NGV; and

C. The Customer desires to receive Customer Compression and Refueling Services in accordance with the provisions of this Service Agreement and Rate Schedule 6C.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the terms, conditions and limitations contained herein, the parties agree as follows:

1. Specific Information:

Estimated Maximum Consumption:	____________________ Gigajoules per day (maximum Day Delivery)
	and ________________ Gigajoules per hour
Commencement Date:	____________________________________
Expiry Date of First Contract Term:	Five years after commencement date
Automatic Contract Extension:	Year to year
Service Address:	____________________________________
Account Number:	____________________________________

Address of Customer for receiving notices:

______________________________ Attention: ______________________
(Name of Customer)

______________________________ Telephone: ______________________
(Address of Customer)

______________________________ Fax: ______________________

______________________________ Email: ______________________

____

2. Compre ssion and Refueling Services

2.1 Terasen Gas will provide such Compression and Refueling Service as it, in its sole discretion, believes will meet the anticipated load of the Customer, based on information provided by the Customer to it.

Without limiting the foregoing and for greater certainty, Compression and Refueling Services will include the following (check off each box as appropriate)

	Yes	No
Electric service to Premises		
Fencing		
Land and buildings (other than compressor enclosure)		
Foundations		
Landscaping		
Engineering drawings		

3. Rate Schedule 6C

3.1 **Additional Terms** - All rates, terms and conditions set out in Rate Schedule 6C of the General Terms and Conditions, as either of them may be amended by Terasen Gas and approved from time to time by the British Columbia Utilities Commission, are in addition to the rates, terms and conditions contained in this Service Agreement and form part of this Service Agreement and bind Terasen Gas and the Customer as set out herein.

3.2 **Payment of Amounts** - Without limiting the generality of the foregoing and except as specified in the Service Agreement, the Customer will pay to Terasen Gas all the amounts set out in Rate Schedule 6C for the services provided under Rate Schedule 6C and this Service Agreement.

3.3 **Conflict** - Where anything in either this Rate Schedule 6C or the General Terms and Conditions of Terasen Gas conflict with any of the rates, terms and conditions set out in this Service Agreement, this Service Agreement governs. Where anything in Rate Schedule 6C conflicts with any of the rates, terms and conditions set out in the General Terms and Conditions of Terasen Gas, Rate Schedule 6C governs.

IN WITNESS WHEREOF the parties hereto have executed this Service Agreement.

TERASEN GAS INC.	______________________________ (here insert name of Customer)
BY: ______________________________ (Signature)	BY: ______________________________ (Signature)
______________________________ (Title)	______________________________ (Title)
______________________________ (Name – Please Print)	______________________________ (Name – Please Print Title)
DATE: ______________________________	DATE: ______________________________

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE	EXISTING JULY 1, 2009 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2010 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$11.84**	**$11.84**	**$11.84**	**$0.00**	**$0.00**	**$0.00**	**$11.84**	**$11.84**	**$11.84**
3										
4	Delivery Charge per GJ	$2.961	$2.961	$2.961	$0.252	$0.252	$0.252	$3.213	$3.213	$3.213
5	Rider 3 ESM	($0.132)	($0.132)	($0.132)	$0.092	$0.092	$0.092	($0.040)	($0.040)	($0.040)
6	Rider 4 Delivery Rate Refund	($0.035)	($0.035)	($0.035)	$0.035	$0.035	$0.035	$0.000	$0.000	$0.000
7	Rider 5 RSAM	$0.001	$0.001	$0.001	($0.054)	($0.054)	($0.054)	($0.053)	($0.053)	($0.053)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.795**	**$2.795**	**$2.795**	**$0.325**	**$0.325**	**$0.325**	**$3.120**	**$3.120**	**$3.120**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$0.942	$0.903	$0.981	$0.000	$0.000	$0.000	$0.942	$0.903	$0.981
13	Rider 8 Unbundling Recovery	$0.073	$0.073	$0.073	$0.000	$0.000	$0.000	$0.073	$0.073	$0.073
14	Subtotal **Midstream Related Charges per GJ**	**$1.015**	**$0.976**	**$1.054**	**$0.000**	**$0.000**	**$0.000**	**$1.015**	**$0.976**	**$1.054**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$5.962**	**$5.962**	**$5.962**	**$0.000**	**$0.000**	**$0.000**	**$5.962**	**$5.962**	**$5.962**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$5.231			$0.000			$5.231	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$12.096**			**$0.000**			**$12.096**	
23	per GJ (Includes Rider 1, excludes Riders 8)									

Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE	EXISTING JULY 1, 2009 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2010 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$24.84**	**$24.84**	**$24.84**	**$0.00**	**$0.00**	**$0.00**	**$24.84**	**$24.84**	**$24.84**
3										
4	Delivery Charge per GJ	$2.479	$2.479	$2.479	$0.188	$0.188	$0.188	$2.667	$2.667	$2.667
5	Rider 3 ESM	($0.100)	($0.100)	($0.100)	$0.071	$0.071	$0.071	($0.029)	($0.029)	($0.029)
6	Rider 4 Delivery Rate Refund	($0.029)	($0.029)	($0.029)	$0.029	$0.029	$0.029	$0.000	$0.000	$0.000
7	Rider 5 RSAM	$0.001	$0.001	$0.001	($0.054)	($0.054)	($0.054)	($0.053)	($0.053)	($0.053)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.351**	**$2.351**	**$2.351**	**$0.234**	**$0.234**	**$0.234**	**$2.585**	**$2.585**	**$2.585**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$0.947	$0.907	$0.986	$0.000	$0.000	$0.000	$0.947	$0.907	$0.986
13	Rider 8 Unbundling Recovery	($0.021)	($0.021)	($0.021)	$0.000	$0.000	$0.000	($0.021)	($0.021)	($0.021)
14	Subtotal **Midstream Related Charges per GJ**	**$0.926**	**$0.886**	**$0.965**	**$0.000**	**$0.000**	**$0.000**	**$0.926**	**$0.886**	**$0.965**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$5.962**	**$5.962**	**$5.962**	**$0.000**	**$0.000**	**$0.000**	**$5.962**	**$5.962**	**$5.962**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$4.136			$0.000			$4.136	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$11.005**			**$0.000**			**$11.005**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE Particulars	EXISTING JULY 1, 2009 RATES Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2010 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$132.52**	**$132.52**	**$132.52**	**$0.00**	**$0.00**	**$0.00**	**$132.52**	**$132.52**	**$132.52**
3										
4	Delivery Charge per GJ	$2.136	$2.136	$2.136	$0.146	$0.146	$0.146	$2.282	$2.282	$2.282
5	Rider 3 ESM	($0.079)	($0.079)	($0.079)	$0.056	$0.056	$0.056	($0.023)	($0.023)	($0.023)
6	Rider 4 Delivery Rate Refund	($0.021)	($0.021)	($0.021)	$0.021	$0.021	$0.021	$0.000	$0.000	$0.000
7	Rider 5 RSAM	$0.001	$0.001	$0.001	($0.054)	($0.054)	($0.054)	($0.053)	($0.053)	($0.053)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.037**	**$2.037**	**$2.037**	**$0.169**	**$0.169**	**$0.169**	**$2.206**	**$2.206**	**$2.206**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$0.830	$0.796	$0.873	$0.000	$0.000	$0.000	$0.830	$0.796	$0.873
13	Rider 8 Unbundling Recovery	($0.021)	($0.021)	($0.021)	$0.000	$0.000	$0.000	($0.021)	($0.021)	($0.021)
14	Subtotal **Midstream Related Charges per GJ**	**$0.809**	**$0.775**	**$0.852**	**$0.000**	**$0.000**	**$0.000**	**$0.809**	**$0.775**	**$0.852**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$5.962**	**$5.962**	**$5.962**	**$0.000**	**$0.000**	**$0.000**	**$5.962**	**$5.962**	**$5.962**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$4.247			$0.000			$4.247	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$11.005**			**$0.000**			**$11.005**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

Line No.	RATE SCHEDULE 4: SEASONAL SERVICE	EFFECTIVE APRIL 1, 2009			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2010 RATES		
	Particulars	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$439.00	$439.00	$439.00	$0.00	$0.00	$0.00	$439.00	$439.00	$439.00
3										
4	**Delivery Charge per GJ**									
5	(a) Off-Peak Period	$0.762	$0.762	$0.762	$0.076	$0.076	$0.076	$0.838	$0.838	$0.838
6	(b) Extension Period	$1.539	$1.539	$1.539	$0.076	$0.076	$0.076	$1.615	$1.615	$1.615
7										
8	**Rider 3 ESM**	($0.061)	($0.061)	($0.061)	$0.050	$0.050	$0.050	($0.011)	($0.011)	($0.011)
9	**Rider 4 Delivery Rate Refund**	($0.001)	($0.001)	($0.001)	$0.001	$0.001	$0.001	$0.000	$0.000	$0.000
10										
11	Commodity Related Charges									
12	**Commodity Cost Recovery Charge**									
13	(a) Off-Peak Period	$5.962	$5.962	$5.962	$0.000	$0.000	$0.000	$5.962	$5.962	$5.962
14	(b) Extension Period	$5.962	$5.962	$5.962	$0.000	$0.000	$0.000	$5.962	$5.962	$5.962
15										
16	**Midstream Cost Recovery Charge per GJ**									
17	(a) Off-Peak Period	$0.670	$0.644	$0.720	$0.000	$0.000	$0.000	$0.670	$0.644	$0.720
18	(b) Extension Period	$0.670	$0.644	$0.720	$0.000	$0.000	$0.000	$0.670	$0.644	$0.720
19										
20										
21	Subtotal Off -Peak Commodity Related Charges per GJ									
22	(a) Off-Peak Period	$6.632	$6.606	$6.682	$0.000	$0.000	$0.000	$6.632	$6.606	$6.682
23	(b) Extension Period	$6.632	$6.606	$6.682	$0.000	$0.000	$0.000	$6.632	$6.606	$6.682
24										
25										
26										
27	Unauthorized Gas Charge per gigajoule	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
28	during peak period									
29										
30										
31	Total Variable Cost per gigajoule between									
32	(a) Off-Peak Period	$7.332	$7.306	$7.382	$0.127	$0.127	$0.127	$7.459	$7.433	$7.509
33	(b) Extension Period	$8.109	$8.083	$8.159	$0.127	$0.127	$0.127	$8.236	$8.210	$8.286

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2010 RATES
BCUC ORDER NO. G-xx-09

Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE Particulars	EFFECTIVE APRIL 1, 2009 Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	PROPOSED JANUARY 1, 2010 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$587.00	$587.00	$587.00	$0.00	$0.00	$0.00	$587.00	$587.00	$587.00
3										
4	**Demand Charge per gigajoule**	$14.655	$14.655	$14.655	$1.035	$1.035	$1.035	$15.690	$15.690	$15.690
5										
6	**Delivery Charge per GJ**	$0.593	$0.593	$0.593	$0.042	$0.042	$0.042	$0.635	$0.635	$0.635
7										
8	**Rider 3 ESM**	($0.060)	($0.060)	($0.060)	$0.043	$0.043	$0.043	($0.017)	($0.017)	($0.017)
9	**Rider 4 Delivery Rate Refund**	($0.018)	($0.018)	($0.018)	$0.018	$0.018	$0.018	$0.000	$0.000	$0.000
10										
11										
12	Commodity Related Charges									
13	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$5.962	$5.962	$5.962	$0.000	$0.000	$0.000	$5.962	$5.962	$5.962
14	**Midstream Cost Recovery Charge per GJ**	$0.670	$0.644	$0.720	$0.000	$0.000	$0.000	$0.670	$0.644	$0.720
15	Subtotal Commodity Related Charges per GJ	**$6.632**	**$6.606**	**$6.682**	**$0.000**	**$0.000**	**$0.000**	**$6.632**	**$6.606**	**$6.682**
16										
17										
18										
19	Total Variable Cost per gigajoule	$7.147	$7.121	$7.197	$0.103	$0.103	$0.103	$7.250	$7.224	$7.300

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2010 RATES
BCUC ORDER NO. G-xx-09

Line No.	RATE SCHEDULE 6: NGV - STATIONS Particulars	EFFECTIVE APRIL 1, 2009 Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2010 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$61.00	$61.00	$61.00	$0.00	$0.00	$0.00	$61.00	$61.00	$61.00
3										
4	**Delivery Charge per GJ**	$3.398	$3.398	$3.398	$0.202	$0.202	$0.202	$3.600	$3.600	$3.600
5										
6	**Rider 3 ESM**	($0.110)	($0.110)	($0.110)	$0.086	$0.086	$0.086	($0.024)	($0.024)	($0.024)
7	**Rider 4 Delivery Rate Refund**	($0.019)	($0.019)	($0.019)	$0.019	$0.019	$0.019	$0.000	$0.000	$0.000
8										
9										
10	Commodity Related Charges									
11	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$5.962	$5.962	$5.962	$0.000	$0.000	$0.000	$5.962	$5.962	$5.962
12	**Midstream Cost Recovery Charge per GJ**	$0.471	$0.446	$0.446	$0.000	$0.000	$0.000	$0.471	$0.446	$0.446
13	Subtotal Commodity Related Charges per GJ	**$6.433**	**$6.408**	**$6.408**	**$0.000**	**$0.000**	**$0.000**	**$6.433**	**$6.408**	**$6.408**
14										
15										
16	Total Variable Cost per gigajoule	$9.702	$9.677	$9.677	$0.307	$0.307	$0.307	$10.009	$9.984	$9.984

Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES	EFFECTIVE APRIL 1, 2009			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2010 RATES		
	Particulars	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$880.00	$880.00	$880.00	$0.00	$0.00	$0.00	$880.00	$880.00	$880.00
3										
4	**Delivery Charge per GJ**	$0.990	$0.990	$0.990	$0.067	$0.067	$0.067	$1.057	$1.057	$1.057
5										
6	**Rider 3 ESM**	($0.036)	($0.036)	($0.036)	$0.026	$0.026	$0.026	($0.010)	($0.010)	($0.010)
7	**Rider 4 Delivery Rate Refund**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
8										
9	Commodity Related Charges									
10	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$5.962	$5.962	$5.962	$0.000	$0.000	$0.000	$5.962	$5.962	$5.962
11	**Midstream Cost Recovery Charge per GJ**	$0.670	$0.644	$0.720	$0.000	$0.000	$0.000	$0.670	$0.644	$0.720
12	Subtotal Commodity Related Charges per GJ	**$6.632**	**$6.606**	**$6.682**	**$0.000**	**$0.000**	**$0.000**	**$6.632**	**$6.606**	**$6.682**
13										
14										
15										
16	Charges per gigajoule for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17										
18										
19										
20										
21										
22	Total Variable Cost per gigajoule	$7.586	$7.560	$7.636	$0.093	$0.093	$0.093	$7.679	$7.653	$7.729

Line No.	RATE SCHEDULE 22: LARGE INDUSTRIAL T-SERVICE	EFFECTIVE APRIL 1, 2009			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2010 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$3,664.00	$3,664.00	$3,664.00	$0.00	$0.00	$0.00	$3,664.00	$3,664.00	$3,664.00
2										
3	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.733	$0.733	$0.733	$0.045	$0.045	$0.045	$0.778	$0.778	$0.778
4										
5	**Rider 3 ESM**	($0.023)	($0.023)	($0.023)	$0.016	$0.016	$0.016	($0.007)	($0.007)	($0.007)
6	**Rider 4 Delivery Rate Refund**	($0.005)	($0.005)	($0.005)	$0.005	$0.005	$0.005	$0.000	$0.000	$0.000
7										
8		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
9	**Charges per gigajoule for UOR Gas**									
10										
11										
12	**Demand Surcharge per gigajoule**	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00	$17.00	$17.00	$17.00
13										
14										
15	**Balancing Service per gigajoule**									
16	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.30	n/a	$0.00	$0.00	n/a	$0.30	$0.30	n/a
17	(b) between and including Nov. 1 and Mar. 31	$1.10	$1.10	n/a	$0.00	$0.00	n/a	$1.10	$1.10	n/a
18										
19										
20	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
21										
22										
23										
24	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
25										
26										
27										
28										
29	Total Variable Cost per gigajoule	$0.705	$0.705	$0.705	$0.066	$0.066	$0.066	$0.771	$0.771	$0.771

RATE SCHEDULE 22A:
LARGE INDUSTRIAL T-SERVICE

Line No.	Particulars	EFFECTIVE APRIL 1, 2009	DELIVERY MARGIN RELATED CHARGES CHANGES	PROPOSED JANUARY 1, 2010 RATES
	(1)	(2)	(3)	(4)
1	**INLAND SERVICE AREA**			
2				
3	**Basic Charge per Month**	$4,810.00	$0.00	$4,810.00
4				
5	**Delivery Charge per gigajoule - Firm**			
6	(a) Firm DTQ	$11.765	$0.731	$12.496
7	(b) Firm MTQ	$0.082	$0.005	$0.087
8				
9	**Delivery Charge per gigajoule - Interr MTQ**	$0.939	$0.052	$0.991
10				
11	**Rider 3 ESM**	($0.022)	$0.015	($0.007)
12	**Rider 4 Delivery Rate Refund**	($0.003)	$0.003	$0.000
13				
14		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
15	**Charges per gigajoule for UOR Gas**			
16				
17				
18	**Demand Surchage per gigajoule**	$17.00	$0.00	$17.00
19				
20	**Balancing Service per gigajoule**			
21	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.00	$0.30
22	(b) between and including Nov. 1 and Mar. 31	$1.10	$0.00	$1.10
23				
24				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
25	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
26				
27				
28	**Replacement Gas**	Sumas Daily Price		Sumas Daily Price
29		plus 20 Percent		plus 20 Percent
30				
31	**Administration Charge per Month**	$78.00	$0.00	$78.00
32				
33	Total Variable Cost per gigajoule			
34	(a) Firm MTQ	$0.057	$0.023	$0.080
35	(b) Interruptible MTQ	$0.914	$0.070	$0.984

Line No.	RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE — Particulars	EFFECTIVE APRIL 1, 2009 Columbia Except Elkview	EFFECTIVE APRIL 1, 2009 Elkview Coal	DELIVERY MARGIN RELATED CHARGES CHANGES Columbia Except Elkview	DELIVERY MARGIN RELATED CHARGES CHANGES Elkview Coal	PROPOSED JANUARY 1, 2010 RATES Columbia Except Elkview	PROPOSED JANUARY 1, 2010 RATES Elkview Coal
	(1)	-2	(3)	(4)	(5)	-6	-7
1	**COLUMBIA SERVICE AREA**						
2							
3	**Basic Charge per Month**	$4,537.00	$4,537.00	$0.00	$0.00	$4,537.00	$4,537.00
4							
5	**Delivery Charge per gigajoule - Firm**						
6	(a) Firm DTQ	$7.496	$1.702	$0.450	$0.102	$7.946	$1.804
7	(b) Firm MTQ	$0.080	$0.080	$0.005	$0.005	$0.085	$0.085
8							
9	**Delivery Charge per gigajoule - Interr MTQ**						
10	(a) between and including Apr. 1 and Oct. 31	$0.747	$0.187	$0.045	$0.011	$0.792	$0.198
11	(b) between and including Nov. 1 and Mar.31	$1.076	$0.267	$0.065	$0.016	$1.141	$0.283
12							
13	**Rider 3 ESM**	($0.018)	($0.007)	$0.013	$0.007	($0.005)	$0.000
14	**Rider 4 Delivery Rate Refund**	($0.003)	($0.003)	$0.003	$0.003	$0.000	$0.000
15							
16		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
17	**Charges per gigajoule for UOR Gas**						
18							
19							
20	**Demand Surchage per gigajoule**	$17.00	$17.00	$0.00	$0.00	$17.00	$17.00
21							
22		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
23	**Charges per gigajoule for Backstopping Gas**						
24							
25							
26	**Administration Charge per Month**	$78.00	$78.00	$0.00	$0.00	$78.00	$78.00
27							
28							
29	Total Variable Cost per gigajoule						
30	(a) Firm MTQ	$0.059	$0.070	$0.021	$0.015	$0.080	$0.085
31	(b) Interruptible MTQ - Summer	$0.726	$0.177	$0.061	$0.021	$0.787	$0.198
32	- Winter	$1.055	$0.257	$0.081	$0.026	$1.136	$0.283

Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE	EFFECTIVE APRIL 1, 2009			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2010 RATES		
	Particulars	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$132.52	$132.52	$132.52	$0.00	$0.00	$0.00	$132.52	$132.52	$132.52
2										
3	**Delivery Charge per gigajoule**	$2.136	$2.136	$2.136	$0.146	$0.146	$0.146	$2.282	$2.282	$2.282
4										
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8	**Sales**									
9	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per gigajoule for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 3 ESM**	($0.079)	($0.079)	($0.079)	$0.056	$0.056	$0.056	($0.023)	($0.023)	($0.023)
15	**Rider 4 Delivery Rate Refund**	($0.022)	($0.022)	($0.022)	$0.022	$0.022	$0.022	$0.000	$0.000	$0.000
16	**Rider 5 RSAM**	$0.001	$0.001	$0.001	($0.054)	($0.054)	($0.054)	($0.053)	($0.053)	($0.053)
17										
18										
19										
20	Total Variable Cost per gigajoule	$2.036	$2.036	$2.036	$0.170	$0.170	$0.170	$2.206	$2.206	$2.206

Line No.	RATE SCHEDULE 25 GENERAL FIRM T-SERVICE	EFFECTIVE APRIL 1, 2009			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2010 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$587.00	$587.00	$587.00	$0.00	$0.00	$0.00	$587.00	$587.00	$587.00
2										
3	**Demand Charge per gigajoule**	$14.655	$14.655	$14.655	$1.035	$1.035	$1.035	$15.690	$15.690	$15.690
4										
5	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.593	$0.593	$0.593	$0.042	$0.042	$0.042	$0.635	$0.635	$0.635
6										
7	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
8										
9										
10	**Sales**									
11	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per gigajoule for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per gigajoule for UOR Gas									
15										
16										
17	**Rider 3 ESM**	($0.060)	($0.060)	($0.060)	$0.043	$0.043	$0.043	($0.017)	($0.017)	($0.017)
18	**Rider 4 Delivery Rate Refund**	($0.012)	($0.012)	($0.012)	$0.012	$0.012	$0.012	$0.000	$0.000	$0.000
19										
20										
21										
22	Total Variable Cost per gigajoule	$0.521	$0.521	$0.521	$0.097	$0.097	$0.097	$0.618	$0.618	$0.618

Line No.	**RATE SCHEDULE 27: INTERRUPTIBLE T-SERVICE** Particulars	**EFFECTIVE APRIL 1, 2009** Lower Mainland			**DELIVERY MARGIN RELATED CHARGES CHANGES** Lower Mainland			**PROPOSED JANUARY 1, 2010 RATES** Lower Mainland		
		Lower Mainland	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$880.00	$880.00	$880.00	$0.00	$0.00	$0.00	$880.00	$880.00	$880.00
2										
3										
4	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.990	$0.990	$0.990	$0.067	$0.067	$0.067	$1.057	$1.057	$1.057
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8										
9	**Sales**									
10	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
11	(b) Charge per gigajoule for Backstopping Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
17	**Rider 3 ESM**	($0.036)	($0.036)	($0.036)	$0.026	$0.026	$0.026	($0.010)	($0.010)	($0.010)
18	**Rider 4 Delivery Rate Refund**	($0.008)	($0.008)	($0.008)	$0.008	$0.008	$0.008	$0.000	$0.000	$0.000
19										
20										
21										
22	Total Variable Cost per gigajoule	$0.946	$0.946	$0.946	$0.101	$0.101	$0.101	$1.047	$1.047	$1.047

TERASEN GAS INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO. G-xx-09

RATE SCHEDULE 1 - RESIDENTIAL SERVICE

Line No.	Particular	EXISTING JULY 1, 2009 RATES			PROPOSED JANUARY 1, 2010 RATES			Annual Increase/Decrease		
		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bil
1	**LOWER MAINLAND SERVICE AREA**									
2	Delivery Margin Related Charges									
3	Basic Charge	12 months x	$11.84 =	$142.08	12 months x	$11.84 =	$142.08	$0.00	$0.00	0.00%
4										
5	Delivery Charge	95.0 GJ x	$2.961 =	281.2950	95.0 GJ x	$3.213 =	305.2350	$0.252	23.9400	2.24%
6	Rider 3 ESM	95.0 GJ x	($0.132) =	(12.5400)	95.0 GJ x	($0.040) =	(3.8000)	$0.092	8.7400	0.82%
7	Rider 4 Delivery Rate Refund	95.0 GJ x	($0.035) =	(3.3250)	95.0 GJ x	$0.000 =	0.00	$0.035	3.3250	0.31%
8	Rider 5 RSAM	95.0 GJ x	$0.001 =	0.0950	95.0 GJ x	($0.053) =	(5.0350)	($0.054)	(5.1300)	-0.48%
9	Subtotal Delivery Margin Related Charges			**$407.61**			**$438.48**		**$30.87**	**2.88%**
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge	95.0 GJ x	$0.942 =	$89.4900	95.0 GJ x	$0.942 =	$89.4900	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	95.0 GJ x	$0.073 =	6.9350	95.0 GJ x	$0.073 =	6.9350	$0.000	0.0000	0.00%
14	Midstream Related Charges Subtotal			$96.43			$96.43		$0.00	0.00%
15										
16	Cost of Gas (Commodity Cost Recovery Charge)	95.0 GJ x	$5.962 =	$566.39	95.0 GJ x	$5.962 =	$566.39	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges			**$662.82**			**$662.82**		**$0.00**	**0.00%**
18										
19	Total *(with effective $/GJ rate)*	95.0	*$11.268*	**$1,070.43**	95.0	*$11.593*	**$1,101.30**	*$0.325*	**$30.87**	**2.88%**
20										
21	**INLAND SERVICE AREA**									
22	Delivery Margin Related Charges									
23	Basic Charge	12 months x	$11.84 =	$142.08	12 months x	$11.84 =	$142.08	$0.00	$0.00	0.00%
24										
25	Delivery Charge	75.0 GJ x	$2.961 =	222.0750	75.0 GJ x	$3.213 =	240.9750	$0.252	18.9000	2.17%
26	Rider 3 ESM	75.0 GJ x	($0.132) =	(9.9000)	75.0 GJ x	($0.040) =	(3.0000)	$0.092	6.9000	0.79%
27	Rider 4 Delivery Rate Refund	75.0 GJ x	($0.035) =	(2.6250)	75.0 GJ x	$0.000 =	0.00	$0.035	2.6250	0.30%
28	Rider 5 RSAM	75.0 GJ x	$0.001 =	0.0750	75.0 GJ x	($0.053) =	(3.9750)	($0.054)	(4.0500)	-0.46%
29	Subtotal Delivery Margin Related Charges			**$351.71**			**$376.08**		**$24.37**	**2.79%**
30										
31	Commodity Related Charges									
32	Midstream Cost Recovery Charge	75.0 GJ x	$0.903 =	$67.7250	75.0 GJ x	$0.903 =	$67.7250	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	75.0 GJ x	$0.073 =	5.4750	75.0 GJ x	$0.073 =	5.4750	$0.000	0.0000	0.00%
34	Midstream Related Charges Subtotal			$73.20			$73.20		$0.00	0.00%
35										
36	Cost of Gas (Commodity Cost Recovery Charge)	75.0 GJ x	$5.962 =	$447.15	75.0 GJ x	$5.962 =	$447.15	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges			**$520.35**			**$520.35**		**$0.00**	**0.00%**
38										
39	Total *(with effective $/GJ rate)*	75.0	*$11.627*	**$872.06**	75.0	*$11.952*	**$896.43**	*$0.325*	**$24.37**	**2.79%**
40										
41	**COLUMBIA SERVICE AREA**									
42	Delivery Margin Related Charges									
43	Basic Charge	12 months x	$11.84 =	$142.08	12 months x	$11.84 =	$142.08	$0.00	$0.00	0.00%
44										
44	Delivery Charge	80.0 GJ x	$2.961 =	236.8800	80.0 GJ x	$3.213 =	257.0400	$0.252	20.1600	2.17%
45	Rider 3 ESM	80.0 GJ x	($0.132) =	(10.5600)	80.0 GJ x	($0.040) =	(3.2000)	$0.092	7.3600	0.79%
46	Rider 4 Delivery Rate Refund	80.0 GJ x	($0.035) =	(2.8000)	80.0 GJ x	$0.000 =	0.00	$0.035	2.8000	0.30%
47	Rider 5 RSAM	80.0 GJ x	$0.001 =	0.0800	80.0 GJ x	($0.053) =	(4.2400)	($0.054)	(4.3200)	-0.47%
48	Subtotal Delivery Margin Related Charges			**$365.68**			**$391.68**		**$26.00**	**2.80%**
49										
50	Commodity Related Charges									
51	Midstream Cost Recovery Charge	80.0 GJ x	$0.981 =	$78.4800	80.0 GJ x	$0.981 =	$78.4800	$0.000	$0.0000	0.00%
52	Rider 8 Unbundling Recovery	80.0 GJ x	$0.073 =	5.8400	80.0 GJ x	$0.073 =	5.8400	$0.000	0.0000	0.00%
53	Midstream Related Charges Subtotal			$84.32			$84.32		$0.00	0.00%
54										
55	Cost of Gas (Commodity Cost Recovery Charge)	80.0 GJ x	$5.962	$476.96	80.0 GJ x	$5.962 =	$476.96	$0.000	$0.00	0.00%
56	Subtotal Commodity Related Charges			**$561.28**	80.0		**$561.28**		**$0.00**	**0.00%**
57										
58	Total *(with effective $/GJ rate)*	80.0	*$11.587*	**$926.96**	80.0	*$11.912*	**$952.96**	*$0.325*	**$26.00**	**2.80%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

RATE SCHEDULE 2 -SMALL COMMERCIAL SERVICE

Line No.	Particular	EXISTING JULY 1, 2009 RATES			PROPOSED JANUARY 1, 2010 RATES			Annual Increase/Decrease		
		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**									
2	Delivery Margin Related Charges									
3	Basic Charge	12 months x	$24.84 =	$298.08	12 months x	$24.84 =	$298.08	$0.00	$0.00	0.00%
4										
5	Delivery Charge	300.0 GJ x	$2.479 =	743.7000	300.0 GJ x	$2.667 =	800.1000	$0.188	56.4000	1.84%
6	Rider 3 ESM	300.0 GJ x	($0.100) =	(30.0000)	300.0 GJ x	($0.029) =	(8.7000)	$0.071	21.3000	0.69%
7	Rider 4 Delivery Rate Refund	300.0 GJ x	($0.029) =	(8.7000)	300.0 GJ x	$0.000 =	0.00	$0.029	8.7000	0.28%
8	Rider 5 RSAM	300.0 GJ x	$0.001 =	0.3000	300.0 GJ x	($0.053) =	(15.9000)	($0.054)	(16.2000)	-0.53%
9	Subtotal Delivery Margin Related Charges			**$1,003.38**			**$1,073.58**		**$70.20**	**2.29%**
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge	300.0 GJ x	$0.947 =	$284.1000	300.0 GJ x	$0.947 =	$284.1000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	300.0 GJ x	($0.021) =	(6.3000)	300.0 GJ x	($0.021) =	(6.3000)	$0.000	0.0000	0.00%
14	Midstream Related Charges Subtotal			$277.80			$277.80		$0.00	0.00%
15										
16	Cost of Gas (Commodity Cost Recovery Charge)	300.0 GJ x	$5.962 =	$1,788.60	300.0 GJ x	$5.962 =	$1,788.60	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges			**$2,066.40**			**$2,066.40**		**$0.00**	**0.00%**
18										
19	Total *(with effective $/GJ rate)*	300.0	*$10.233*	**$3,069.78**	300.0	*$10.467*	**$3,139.98**	*$0.234*	**$70.20**	**2.29%**
20										
21	**INLAND SERVICE AREA**									
22	Delivery Margin Related Charges									
23	Basic Charge	12 months x	$24.84 =	$298.08	12 months x	$24.84 =	$298.08	$0.00	$0.00	0.00%
24										
25	Delivery Charge	250.0 GJ x	$2.479 =	619.7500	250.0 GJ x	$2.667 =	666.7500	$0.188	47.0000	1.81%
26	Rider 3 ESM	250.0 GJ x	($0.100) =	(25.0000)	250.0 GJ x	($0.029) =	(7.2500)	$0.071	17.7500	0.68%
27	Rider 4 Delivery Rate Refund	250.0 GJ x	($0.029) =	(7.2500)	250.0 GJ x	$0.000 =	0.00	$0.029	7.2500	0.28%
28	Rider 5 RSAM	250.0 GJ x	$0.001 =	0.2500	250.0 GJ x	($0.053) =	(13.2500)	($0.054)	(13.5000)	-0.52%
29	Subtotal Delivery Margin Related Charges			**$885.83**			**$944.33**		**$58.50**	**2.25%**
30										
31	Commodity Related Charges									
32	Midstream Cost Recovery Charge	250.0 GJ x	$0.907 =	$226.7500	250.0 GJ x	$0.907 =	$226.7500	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	250.0 GJ x	($0.021) =	(5.2500)	250.0 GJ x	($0.021) =	(5.2500)	$0.000	0.0000	0.00%
34	Midstream Related Charges Subtotal			$221.50			$221.50		$0.00	0.00%
35										
36	Cost of Gas (Commodity Cost Recovery Charge)	250.0 GJ x	$5.962 =	$1,490.50	250.0 GJ x	$5.962 =	$1,490.50	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges			**$1,712.00**			**$1,712.00**		**$0.00**	**0.00%**
38										
39	Total *(with effective $/GJ rate)*	250.0	*$10.391*	**$2,597.83**	250.0	*$10.625*	**$2,656.33**	*$0.234*	**$58.50**	**2.25%**
40										
41	**COLUMBIA SERVICE AREA**									
42	Delivery Margin Related Charges									
43	Basic Charge	12 months x	$24.84 =	$298.08	12 months x	$24.84 =	$298.08	$0.00	$0.00	0.00%
44										
45	Delivery Charge	320.0 GJ x	$2.479 =	793.2800	320.0 GJ x	$2.667 =	853.4400	$0.188	60.1600	1.84%
46	Rider 3 ESM	320.0 GJ x	($0.100) =	(32.0000)	320.0 GJ x	($0.029) =	(9.2800)	$0.071	22.7200	0.70%
47	Rider 4 Delivery Rate Refund	320.0 GJ x	($0.029) =	(9.2800)	320.0 GJ x	$0.000 =	0.00	$0.029	9.2800	0.28%
48	Rider 5 RSAM	320.0 GJ x	$0.001 =	0.3200	320.0 GJ x	($0.053) =	(16.9600)	($0.054)	(17.2800)	-0.53%
49	Subtotal Delivery Margin Related Charges			**$1,050.40**			**$1,125.28**		**$74.88**	**2.29%**
50										
51	Commodity Related Charges									
52	Midstream Cost Recovery Charge	320.0 GJ x	$0.986 =	$315.5200	320.0 GJ x	$0.986 =	$315.5200	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	320.0 GJ x	($0.021) =	(6.7200)	320.0 GJ x	($0.021) =	(6.7200)	$0.000	0.0000	0.00%
54	Midstream Related Charges Subtotal			$308.80			$308.80		$0.00	0.00%
55										
56	Cost of Gas (Commodity Cost Recovery Charge)	320.0 GJ x	$5.962 =	$1,907.84	320.0 GJ x	$5.962 =	$1,907.84	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges			**$2,216.64**			**$2,216.64**		**$0.00**	**0.00%**
58										
59	Total *(with effective $/GJ rate)*	320.0	*$10.210*	**$3,267.04**	320.0	*$10.444*	**$3,341.92**	*$0.234*	**$74.88**	**2.29%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

RATE SCHEDULE 3 - LARGE COMMERCIAL SERVICE

Line No.	Particular	EXISTING JULY 1, 2009 RATES Volume		Rate		Annual $	PROPOSED JANUARY 1, 2010 RATES Volume		Rate		Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bil
1	**LOWER MAINLAND SERVICE AREA**													
2	Delivery Margin Related Charges													
3	Basic Charge	12	months x	$132.52	=	$1,590.24	12	months x	$132.52	=	$1,590.24	$0.00	$0.00	0.00%
4														
5	Delivery Charge	2,800.0	GJ x	$2.136	=	5,980.8000	2,800.0	GJ x	$2.282	=	6,389.6000	$0.146	408.8000	1.56%
6	Rider 3 ESM	2,800.0	GJ x	($0.079)	=	(221.2000)	2,800.0	GJ x	($0.023)	=	(64.4000)	$0.056	156.8000	0.60%
7	Rider 4 Delivery Rate Refund	2,800.0	GJ x	($0.021)	=	(58.8000)	2,800.0	GJ x	$0.000	=	0.00	$0.021	58.8000	0.22%
8	Rider 5 RSAM	2,800.0	GJ x	$0.001	=	2.8000	2,800.0	GJ x	($0.053)	=	(148.4000)	($0.054)	(151.2000)	-0.58%
9	Subtotal Delivery Margin Related Charges					**$7,293.84**					**$7,767.04**		**$473.20**	**1.80%**
10														
11	Commodity Related Charges													
12	Midstream Cost Recovery Charge	2,800.0	GJ x	$0.830	=	$2,324.0000	2,800.0	GJ x	$0.830	=	$2,324.0000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	2,800.0	GJ x	($0.021)	=	(58.8000)	2,800.0	GJ x	($0.021)	=	(58.8000)	$0.000	0.0000	0.00%
14	Midstream Related Charges Subtotal					$2,265.20					$2,265.20		$0.00	0.00%
15														
16	Cost of Gas (Commodity Cost Recovery Charge)	2,800.0	GJ x	$5.962	=	$16,693.60	2,800.0	GJ x	$5.962	=	$16,693.60	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges					**$18,958.80**					**$18,958.80**		**$0.00**	**0.00%**
18														
19	Total *(with effective $/GJ rate)*	2,800.0		*$9.376*		**$26,252.64**	2,800.0		*$9.545*		**$26,725.84**	*$0.169*	**$473.20**	**1.80%**
20														
21	**INLAND SERVICE AREA**													
22	Delivery Margin Related Charges													
23	Basic Charge	12	months x	$132.52	=	$1,590.24	12	months x	$132.52	=	$1,590.24	$0.00	$0.00	0.00%
24														
25	Delivery Charge	2,600.0	GJ x	$2.136	=	5,553.6000	2,600.0	GJ x	$2.282	=	5,933.2000	$0.146	379.6000	1.56%
26	Rider 3 ESM	2,600.0	GJ x	($0.079)	=	(205.4000)	2,600.0	GJ x	($0.023)	=	(59.8000)	$0.056	145.6000	0.60%
27	Rider 4 Delivery Rate Refund	2,600.0	GJ x	($0.021)	=	(54.6000)	2,600.0	GJ x	$0.000	=	0.00	$0.021	54.6000	0.22%
28	Rider 5 RSAM	2,600.0	GJ x	$0.001	=	2.6000	2,600.0	GJ x	($0.053)	=	(137.8000)	($0.054)	(140.4000)	-0.58%
29	Subtotal Delivery Margin Related Charges					**$6,886.44**					**$7,325.84**		**$439.40**	**1.80%**
30														
31	Commodity Related Charges													
32	Midstream Cost Recovery Charge	2,600.0	GJ x	$0.796	=	$2,069.6000	2,600.0	GJ x	$0.796	=	$2,069.6000	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	2,600.0	GJ x	($0.021)	=	(54.6000)	2,600.0	GJ x	($0.021)	=	(54.6000)	$0.000	0.0000	0.00%
34	Midstream Related Charges Subtotal					$2,015.00					$2,015.00		$0.00	0.00%
35														
36	Cost of Gas (Commodity Cost Recovery Charge)	2,600.0	GJ x	$5.962	=	$15,501.20	2,600.0	GJ x	$5.962	=	$15,501.20	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges					**$17,516.20**					**$17,516.20**		**$0.00**	**0.00%**
38														
39	Total *(with effective $/GJ rate)*	2,600.0		*$9.386*		**$24,402.64**	2,600.0		*$9.555*		**$24,842.04**	*$0.169*	**$439.40**	**1.80%**
40														
41	**COLUMBIA SERVICE AREA**													
42	Delivery Margin Related Charges													
43	Basic Charge	12	months x	$132.52	=	$1,590.24	12	months x	$132.52	=	$1,590.24	$0.00	$0.00	0.00%
44														
45	Delivery Charge	3,300.0	GJ x	$2.136	=	7,048.8000	3,300.0	GJ x	$2.282	=	7,530.6000	$0.146	481.8000	1.56%
46	Rider 3 ESM	3,300.0	GJ x	($0.079)	=	(260.7000)	3,300.0	GJ x	($0.023)	=	(75.9000)	$0.056	184.8000	0.60%
47	Rider 4 Delivery Rate Refund	3,300.0	GJ x	($0.021)	=	(69.3000)	3,300.0	GJ x	$0.000	=	0.00	$0.021	69.3000	0.23%
48	Rider 5 RSAM	3,300.0	GJ x	$0.001	=	3.3000	3,300.0	GJ x	($0.053)	=	(174.9000)	($0.054)	(178.2000)	-0.58%
49	Subtotal Delivery Margin Related Charges					**$8,312.34**					**$8,870.04**		**$557.70**	**1.81%**
50														
51	Commodity Related Charges													
52	Midstream Cost Recovery Charge	3,300.0	GJ x	$0.873	=	$2,880.9000	3,300.0	GJ x	$0.873	=	$2,880.9000	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	3,300.0	GJ x	($0.021)	=	(69.3000)	3,300.0	GJ x	($0.021)	=	(69.3000)	$0.000	0.0000	0.00%
54	Midstream Related Charges Subtotal					$2,811.60					$2,811.60		$0.00	0.00%
55														
56	Cost of Gas (Commodity Cost Recovery Charge)	3,300.0	GJ x	$5.962	=	$19,674.60	3,300.0	GJ x	$5.962	=	$19,674.60	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges					**$22,486.20**					**$22,486.20**		**$0.00**	**0.00%**
58														
59	Total *(with effective $/GJ rate)*	3,300.0		*$9.333*		**$30,798.54**	3,300.0		*$9.502*		**$31,356.24**	*$0.169*	**$557.70**	**1.81%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

TERASEN GAS INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO. G-xx-09

RATE SCHEDULE 4 - SEASONAL SERVICE

Line No.	Particular	EFFECTIVE APRIL 1, 2009			PROPOSED JANUARY 1, 2010 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bil
2	**LOWER MAINLAND SERVICE AREA**									
3	Delivery Margin Related Charges									
4	Basic Charge	7 months x	$439.00 =	$3,073.00	7 months x	$439.00 =	$3,073.00	$0.00	$0.00	0.00%
5										
6	Delivery Charge									
7	(a) Off-Peak Period	5,400.0 GJ x	$0.762 =	4,114.8000	5,400.0 GJ x	$0.838 =	4,525.2000	$0.076	410.4000	0.96%
8	(b) Extension Period	0.0 GJ x	$1.539 =	0.0000	0.0 GJ x	$1.615 =	0.0000	$0.076	0.0000	0.00%
9	Rider 3 ESM	5,400.0 GJ x	($0.061) =	(329.4000)	5,400.0 GJ x	($0.011) =	(59.4000)	$0.050	270.0000	0.63%
10	Rider 4 Delivery Rate Refund	5,400.0 GJ x	($0.001) =	(5.4000)	5,400.0 GJ x	$0.000 =	0.0000	$0.001	5.4000	0.01%
11	Subtotal Delivery Margin Related Charges			**$6,853.00**			**$7,538.80**		**$685.80**	**1.61%**
12										
13	Commodity Related Charges									
14	Midstream Cost Recovery Charge									
15	(a) Off-Peak Period	5,400.0 GJ x	$0.670 =	$3,618.0000	5,400.0 GJ x	$0.670 =	$3,618.0000	$0.000	$0.0000	0.00%
16	(b) Extension Period	0.0 GJ x	$0.670 =	0.0000	0.0 GJ x	$0.670 =	0.0000	$0.000	0.0000	0.00%
17	Commodity Cost Recovery Charge									
18	(a) Off-Peak Period	5,400.0 GJ x	$5.962 =	32,194.8000	5,400.0 GJ x	$5.962 =	32,194.8000	$0.000	0.0000	0.00%
19	(b) Extension Period	0.0 GJ x	$5.962 =	0.0000	0.0 GJ x	$5.962 =	0.0000	$0.000	0.0000	0.00%
20										
21	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak			**$35,812.80**			**$35,812.80**		**$0.00**	**0.00%**
22										
23	Unauthorized Gas Charge During Peak Period (not forecast)									
24										
25	Total during Off-Peak Period	5,400.0		**$42,665.80**	5,400.0		**$43,351.60**		**$685.80**	**1.61%**
26										
27										
28	**INLAND SERVICE AREA**									
29	Delivery Margin Related Charges									
30	Basic Charge	7 months x	$439.00 =	$3,073.00	7 months x	$439.00 =	$3,073.00	$0.00	$0.00	0.00%
31										
32	Delivery Charge									
33	(a) Off-Peak Period	9,300.0 GJ x	$0.762 =	7,086.6000	9,300.0 GJ x	$0.838 =	7,793.4000	$0.076	706.8000	1.00%
34	(b) Extension Period	0.0 GJ x	$1.539 =	0.0000	0.0 GJ x	$1.615 =	0.0000	$0.076	0.0000	0.00%
35	Rider 3 ESM	9,300.0 GJ x	($0.061) =	(567.3000)	9,300.0 GJ x	($0.011) =	(102.3000)	$0.050	465.0000	0.65%
36	Rider 4 Delivery Rate Refund	9,300.0 GJ x	($0.001) =	(9.3000)	9,300.0 GJ x	$0.000 =	0.0000	$0.001	9.3000	0.01%
37	Subtotal Delivery Margin Related Charges			**$9,583.00**			**$10,764.10**		**$1,181.10**	**1.66%**
38										
39	Commodity Related Charges									
40	Midstream Cost Recovery Charge									
41	(a) Off-Peak Period	9,300.0 GJ x	$0.644 =	$5,989.2000	9,300.0 GJ x	$0.644 =	$5,989.2000	$0.000	$0.0000	0.00%
42	(b) Extension Period	0.0 GJ x	$0.644 =	0.0000	0.0 GJ x	$0.644 =	0.0000	$0.000	0.0000	0.00%
43	Commodity Cost Recovery Charge									
44	(a) Off-Peak Period	9,300.0 GJ x	$5.962 =	55,446.6000	9,300.0 GJ x	$5.962 =	55,446.6000	$0.000	0.0000	0.00%
45	(b) Extension Period	0.0 GJ x	$5.962 =	0.0000	0.0 GJ x	$5.962 =	0.0000	$0.000	0.0000	0.00%
46										
47	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak			**$61,435.80**			**$61,435.80**		**$0.00**	**0.00%**
48										
49	Unauthorized Gas Charge During Peak Period (not forecast)									
50										
51	Total during Off-Peak Period	9,300.0		**$71,018.80**	9,300.0		**$72,199.90**		**$1,181.10**	**1.66%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

RATE SCHEDULE 5 -GENERAL FIRM SERVICE

Line No.	Particular	EFFECTIVE APRIL 1, 2009				PROPOSED JANUARY 1, 2010 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bil
2	**LOWER MAINLAND SERVICE AREA**											
3	Delivery Margin Related Charges											
4	Basic Charge	12	months x	$587.00 =	**$7,044.00**	12	months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
5												
6	Demand Charge	58.5	GJ x	$14.655 =	**$10,287.81**	58.5	GJ x	$15.690 =	**$11,014.38**	$1.035	**$726.57**	**0.84%**
7												
8	Delivery Charge	9,700.0	GJ x	$0.593 =	$5,752.1000	9,700.0	GJ x	$0.635 =	$6,159.5000	$0.042	$407.4000	0.47%
9	Rider 3 ESM	9,700.0	GJ x	($0.060) =	(582.0000)	9,700.0	GJ x	($0.017) =	(164.9000)	$0.043	417.1000	0.48%
10	Rider 4 Delivery Rate Refund	9,700.0	GJ x	($0.018) =	(174.6000)	9,700.0	GJ x	$0.000 =	0.0000	$0.018	174.6000	0.20%
11	Subtotal Delivery Margin Related Charges				**$4,995.50**				**$5,994.60**		**$999.10**	**1.15%**
12												
13	Commodity Related Charges											
14	Midstream Cost Recovery Charge	9,700.0	GJ x	$0.670 =	$6,499.0000	9,700.0	GJ x	$0.670 =	$6,499.0000	$0.000	$0.0000	0.00%
15	Commodity Cost Recovery Charge	9,700.0	GJ x	$5.962 =	57,831.4000	9,700.0	GJ x	$5.962 =	57,831.4000	$0.000	0.0000	0.00%
16	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$64,330.40**				**$64,330.40**		**$0.00**	**0.00%**
17												
18	Total *(with effective $/GJ rate)*	9,700.0		*$8.934*	**$86,657.71**	9,700.0		*$9.112*	**$88,383.38**	*$0.178*	**$1,725.67**	**1.99%**
19												
20	**INLAND SERVICE AREA**											
21	Delivery Margin Related Charges											
22	Basic Charge	12	months x	$587.00 =	**$7,044.00**	12	months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
23												
24	Demand Charge	82.0	GJ x	$14.655 =	**$14,420.52**	82.0	GJ x	$15.690 =	**$15,438.96**	$1.035	**$1,018.44**	**0.90%**
25												
26	Delivery Charge	12,800.0	GJ x	$0.593 =	$7,590.4000	12,800.0	GJ x	$0.635 =	$8,128.0000	$0.042	$537.6000	0.48%
27	Rider 3 ESM	12,800.0	GJ x	($0.060) =	(768.0000)	12,800.0	GJ x	($0.017) =	(217.6000)	$0.043	550.4000	0.49%
28	Rider 4 Delivery Rate Refund	12,800.0	GJ x	($0.018) =	(230.4000)	12,800.0	GJ x	$0.000 =	0.0000	$0.018	230.4000	0.20%
29	Subtotal Delivery Margin Related Charges				**$6,592.00**				**$7,910.40**		**$1,318.40**	**1.17%**
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	12,800.0	GJ x	$0.644 =	$8,243.2000	12,800.0	GJ x	$0.644 =	$8,243.2000	$0.000	$0.0000	0.00%
33	Commodity Cost Recovery Charge	12,800.0	GJ x	$5.962 =	76,313.6000	12,800.0	GJ x	$5.962 =	76,313.6000	$0.000	0.0000	0.00%
34	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$84,556.80**				**$84,556.80**		**$0.00**	**0.00%**
35												
36	Total *(with effective $/GJ rate)*	12,800.0		*$8.798*	**$112,613.32**	12,800.0		*$8.980*	**$114,950.16**	*$0.183*	**$2,336.84**	**2.08%**
37												
38	**COLUMBIA SERVICE AREA**											
39	Delivery Margin Related Charges											
40	Basic Charge	12	months x	$587.00 =	**$7,044.00**	12	months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
41												
42	Demand Charge	55.4	GJ x	$14.655 =	**$9,742.64**	55.4	GJ x	$15.690 =	**$10,430.71**	$1.035	**$688.07**	**0.84%**
43												
44	Delivery Charge	9,100.0	GJ x	$0.593 =	$5,396.3000	9,100.0	GJ x	$0.635 =	$5,778.5000	$0.042	$382.2000	0.46%
45	Rider 3 ESM	9,100.0	GJ x	($0.060) =	(546.0000)	9,100.0	GJ x	($0.017) =	(154.7000)	$0.043	391.3000	0.48%
46	Rider 4 Delivery Rate Refund	9,100.0	GJ x	($0.018) =	(163.8000)	9,100.0	GJ x	$0.000 =	0.0000	$0.018	163.8000	0.20%
47	Subtotal Delivery Margin Related Charges				**$4,686.50**				**$5,623.80**		**$937.30**	**1.14%**
48												
49	Commodity Related Charges											
50	Midstream Cost Recovery Charge	9,100.0	GJ x	$0.720 =	$6,552.0000	9,100.0	GJ x	$0.720 =	$6,552.0000	$0.000	$0.0000	0.00%
51	Commodity Cost Recovery Charge	9,100.0	GJ x	$5.962 =	54,254.2000	9,100.0	GJ x	$5.962 =	54,254.2000	$0.000	0.0000	0.00%
52	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$60,806.20**				**$60,806.20**		**$0.00**	**0.00%**
53												
54	Total *(with effective $/GJ rate)*	9,100.0		$9.042	**$82,279.34**	9,100.0		$9.220	**$83,904.71**	*$0.179*	**$1,625.37**	**1.98%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

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RATE SCHEDULE 6 - NGV - STATIONS

Line No.	Particular	EFFECTIVE APRIL 1, 2009				PROPOSED JANUARY 1, 2010 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bil
2	**LOWER MAINLAND SERVICE AREA**											
3	Delivery Margin Related Charges											
4	Basic Charge	12	months x	$61.00 =	$732.00	12	months x	$61.00 =	$732.00	$0.00	$0.00	0.00%
5												
6	Delivery Charge	2,900.0	GJ x	$3.398 =	9,854.2000	2,900.0	GJ x	$3.600 =	10,440.0000	$0.202	585.8000	2.03%
7	Rider 3 ESM	2,900.0	GJ x	($0.110) =	(319.0000)	2,900.0	GJ x	($0.024) =	(69.6000)	$0.086	249.4000	0.86%
8	Rider 4 Delivery Rate Refund	2,900.0	GJ x	($0.019) =	(55.1000)	2,900.0	GJ x	$0.000 =	0.0000	$0.019	55.1000	0.19%
9	Subtotal Delivery Margin Related Charges				**$10,212.10**				**$11,102.40**		**$890.30**	**3.08%**
10												
11	Commodity Related Charges											
12	Midstream Cost Recovery Charge	2,900.0	GJ x	$0.471 =	$1,365.9000	2,900.0	GJ x	$0.471 =	$1,365.9000	$0.000	$0.0000	0.00%
13	Commodity Cost Recovery Charge	2,900.0	GJ x	$5.962 =	17,289.8000	2,900.0	GJ x	$5.962 =	17,289.8000	$0.000	0.0000	0.00%
14	Subtotal Cost of Gas (Commodity Related Charge)				**$18,655.70**				**$18,655.70**		**$0.00**	**0.00%**
15												
16	Total *(with effective $/GJ rate)*	2,900.0		*$9.954*	**$28,867.80**	2,900.0		*$10.261*	**$29,758.10**	*$0.307*	**$890.30**	**3.08%**
17												
18												
19	**INLAND SERVICE AREA**											
20	Delivery Margin Related Charges											
21	Basic Charge	12	months x	$61.00 =	$732.00	12	months x	$61.00 =	$732.00	$0.00	$0.00	0.00%
22												
23	Delivery Charge	11,900.0	GJ x	$3.398 =	40,436.2000	11,900.0	GJ x	$3.600 =	42,840.0000	$0.202	2,403.8000	2.07%
24	Rider 3 ESM	11,900.0	GJ x	($0.110) =	(1,309.0000)	11,900.0	GJ x	($0.024) =	(285.6000)	$0.086	1,023.4000	0.88%
25	Rider 4 Delivery Rate Refund	11,900.0	GJ x	($0.019) =	(226.1000)	11,900.0	GJ x	$0.000 =	0.0000	$0.019	226.1000	0.20%
26	Subtotal Delivery Margin Related Charges				**$39,633.10**				**$43,286.40**		**$3,653.30**	**3.15%**
27												
28	Commodity Related Charges											
29	Midstream Cost Recovery Charge	11,900.0	GJ x	$0.446 =	$5,307.4000	11,900.0	GJ x	$0.446 =	$5,307.4000	$0.000	$0.0000	0.00%
30	Commodity Cost Recovery Charge	11,900.0	GJ x	$5.962 =	70,947.8000	11,900.0	GJ x	$5.962 =	70,947.8000	$0.000	0.0000	0.00%
31	Subtotal Cost of Gas (Commodity Related Charge)				**$76,255.20**				**$76,255.20**		**$0.00**	**0.00%**
32												
33	Total *(with effective $/GJ rate)*	11,900.0		*$9.739*	**$115,888.30**	11,900.0		*$10.046*	**$119,541.60**	*$0.307*	**$3,653.30**	**3.15%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

TERASEN GAS INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO. G-xx-09

RATE SCHEDULE 7 - INTERRUPTIBLE SALES

Line No.	Particular	EFFECTIVE APRIL 1, 2009			PROPOSED JANUARY 1, 2010 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bil
2	**LOWER MAINLAND SERVICE AREA**									
3	Delivery Margin Related Charges									
4	Basic Charge	12 months x	$880.00 =	**$10,560.00**	12 months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
5										
6	Delivery Charge	8,100.0 GJ x	$0.990 =	$8,019.0000	8,100.0 GJ x	$1.057 =	$8,561.7000	$0.067	$542.7000	0.75%
7	Rider 3 ESM	8,100.0 GJ x	($0.036) =	(291.6000)	8,100.0 GJ x	($0.010) =	(81.0000)	$0.026	210.6000	0.29%
8	Rider 4 Delivery Rate Refund	8,100.0 GJ x	$0.000 =	0.0000	8,100.0 GJ x	$0.000 =	0.0000	$0.000	0.0000	0.00%
9	Subtotal Delivery Margin Related Charges			**$7,727.40**			**$8,480.70**		**$753.30**	**1.05%**
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge	8,100.0 GJ x	$0.670 =	$5,427.0000	8,100.0 GJ x	$0.670 =	$5,427.0000	$0.000	$0.0000	0.00%
13	Commodity Cost Recovery Charge	8,100.0 GJ x	$5.962 =	48,292.2000	8,100.0 GJ x	$5.962 =	48,292.2000	$0.000	0.0000	0.00%
14	Subtotal Gas Sales - Fixed (Commodity Related Charge)			**$53,719.20**			**$53,719.20**		**$0.00**	**0.00%**
15										
16	Non-Standard Charges (not forecast)									
17	Index Pricing Option, UOR									
18										
19	Total *(with effective $/GJ rate)*	8,100.0	*$8.890*	**$72,006.60**	8,100.0	*$8.983*	**$72,759.90**	*$0.093*	**$753.30**	**1.05%**
20										
21										
22	**INLAND SERVICE AREA**									
23	Delivery Margin Related Charges									
24	Basic Charge	12 months x	$880.00 =	**$10,560.00**	12 months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
25										
26	Delivery Charge	4,000.0 GJ x	$0.990 =	$3,960.0000	4,000.0 GJ x	$1.057 =	$4,228.0000	$0.067	$268.0000	0.66%
27	Rider 3 ESM	4,000.0 GJ x	($0.036) =	(144.0000)	4,000.0 GJ x	($0.010) =	(40.0000)	$0.026	104.0000	0.25%
28	Rider 4 Delivery Rate Refund	4,000.0 GJ x	$0.000 =	0.0000	4,000.0 GJ x	$0.000 =	0.0000	$0.000	0.0000	0.00%
29	Subtotal Delivery Margin Related Charges			**$3,816.00**			**$4,188.00**		**$372.00**	**0.91%**
30										
31	Commodity Related Charges									
32	Midstream Cost Recovery Charge	4,000.0 GJ x	$0.644 =	$2,576.0000	4,000.0 GJ x	$0.644 =	$2,576.0000	$0.000	$0.0000	0.00%
33	Commodity Cost Recovery Charge	4,000.0 GJ x	$5.962 =	23,848.0000	4,000.0 GJ x	$5.962 =	23,848.0000	$0.000	0.0000	0.00%
34	Subtotal Gas Sales - Fixed (Commodity Related Charge)			**$26,424.00**			**$26,424.00**		**$0.00**	**0.00%**
35										
36	Non-Standard Charges (not forecast)									
37	Index Pricing Option, UOR									
38										
39	Total *(with effective $/GJ rate)*	4,000.0	*$10.200*	**$40,800.00**	4,000.0	*$10.293*	**$41,172.00**	*$0.093*	**$372.00**	**0.91%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

TERASEN GAS INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO. G-xx-09

RATE SCHEDULE 22 - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	EFFECTIVE APRIL 1, 2009						PROPOSED JANUARY 1, 2010 RATES						Annual Increase/Decrease		
1		Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Annual Bil
2	**LOWER MAINLAND SERVICE AREA**															
3	Basic Charge	12	months x	$3,664.00	=	**$43,968.00**		12	months x	$3,664.00	=	**$43,968.00**		$0.00	**$0.00**	**0.00%**
4																
5																
6	Delivery Charge - Interruptible MTQ	467,305.6	GJ x	$0.733	=	$342,535.0048		467,305.6	GJ x	$0.778	=	$363,563.7568		$0.045	$21,028.7520	5.62%
7	Rider 3 ESM	467,305.6	GJ x	($0.023)	=	(10,748.0288)		467,305.6	GJ x	($0.007)	=	(3,271.1392)		$0.016	7,476.8896	2.00%
8	Rider 4 Delivery Rate Refund	467,305.6	GJ x	($0.005)	=	(2,336.5280)		467,305.6	GJ x	$0.000	=	0.00		$0.005	2,336.5280	0.62%
9	Transportation - Interruptible					**$329,450.45**						**$360,292.62**			**$30,842.17**	**8.24%**
10																
11																
12	Non-Standard Charges (not forecast)															
13	UOR, Demand Surcharge, Balancing Service, Backstopping Gas															
14																
15																
16	Administration Charge	12	months x	$78.00	=	**$936.00**		12	months x	$78.00	=	**$936.00**		$0.00	**$0.00**	**0.00%**
17																
18																
19	Total *(with effective $/GJ rate)*	467,305.6		*$0.801*		**$374,354.45**		467,305.6		*$0.867*		**$405,196.62**		*$0.066*	**$30,842.17**	**8.24%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

TERASEN GAS INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO. G-xx-09

RATE SCHEDULE 22A - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	EFFECTIVE APRIL 1, 2009					PROPOSED JANUARY 1, 2010 RATES					Annual Increase/Decrease		
1		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bil
2	**INLAND SERVICE AREA**													
3	Basic Charge	12	months x	$4,810.00	=	**$57,720.00**	12	months x	$4,810.00	=	**$57,720.00**	$0.00	**$0.00**	**0.00%**
4														
5														
6	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,595.4	GJ x	$11.765	=	**$366,418.56**	2,595.4	GJ x	$12.496	=	**$389,185.44**	$0.731	**$22,766.88**	**4.70%**
7														
8														
9	Delivery Charge - Firm MTQ	584,475.8	GJ x	$0.082	=	$47,927.0156	584,475.8	GJ x	$0.087	=	$50,849.3946	$0.005	$2,922.3790	0.60%
10	Rider 3 ESM	584,475.8	GJ x	($0.022)	=	(12,858.4676)	584,475.8	GJ x	($0.007)	=	(4,091.3306)	$0.015	8,767.1370	1.81%
11	Rider 4 Delivery Rate Refund	584,475.8	GJ x	($0.003)	=	(1,753.4274)	584,475.8	GJ x	$0.000	=	0.0000	$0.003	1,753.4274	0.36%
12	Transportation - Firm (Delivery Charge Firm MTQ)					**$33,315.12**					**$46,758.06**		**$13,442.94**	**2.77%**
13														
14														
15	Delivery Charge - Interruptible MTQ	28,607.9	GJ x	$0.939	=	$26,862.8181	28,607.9	GJ x	$0.991	=	$28,350.4289	$0.052	$1,487.6108	0.31%
16	Rider 3 ESM	28,607.9	GJ x	($0.022)	=	(629.3738)	28,607.9	GJ x	($0.007)	=	(200.2553)	$0.015	429.1185	0.09%
17	Rider 4 Delivery Rate Refund	28,607.9	GJ x	($0.003)	=	(85.8237)	28,607.9	GJ x	$0.000	=	0.0000	$0.003	85.8237	0.02%
18	Transportation - Interruptible (Delivery Charge Interruptible MTQ)					**$26,147.62**					**$28,150.17**		**$2,002.55**	**0.41%**
19														
20														
21	Non-Standard Charges (not forecast)													
22	UOR, Demand Surcharge, Balancing Service, Backstopping Gas													
23														
24														
25	Administration Charge	12	months x	$78.00	=	**$936.00**	12	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
26														
27														
28	Total *(with effective $/GJ rate)*	584,475.8		*$0.829*		**$484,537.30**	584,475.8		*$0.894*		**$522,749.67**	*$0.065*	**$38,212.37**	**7.89%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

RATE SCHEDULE 22B - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	EFFECTIVE APRIL 1, 2009				PROPOSED JANUARY 1, 2010 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bil
2	**COLUMBIA SERVICE - EXCEPT ELKVIEW COAL**											
3	Basic Charge	12	months x	$4,537.00 =	**$54,444.00**	12	months x	$4,537.00 =	**$54,444.00**	$0.00	**$0.00**	**0.00%**
4												
5	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,211.8	GJ x	$7.496 =	**$198,955.80**	2,211.8	GJ x	$7.946 =	**$210,899.52**	$0.450	**$11,943.72**	**4.17%**
6												
7	Delivery Charge - Firm MTQ	457,345.8	GJ x	$0.080 =	$36,587.6640	457,345.8	GJ x	$0.085 =	$38,874.3930	$0.005	$2,286.7290	0.80%
8	Rider 3 ESM	457,345.8	GJ x	($0.018) =	(8,232.2244)	457,345.8	GJ x	($0.005) =	(2,286.7290)	$0.013	5,945.4954	2.08%
9	Rider 4 Delivery Rate Refund	457,345.8	GJ x	($0.003) =	(1,372.0374)	457,345.8	GJ x	$0.000 =	0.0000	$0.003	1,372.0374	0.48%
10	Transportation - Firm (Delivery Charge Firm MTQ)				**$26,983.40**				**$36,587.66**		**$9,604.26**	**3.36%**
11												
12	Delivery Charge - Interruptible MTQ											
13	- Apr. 1 to Nov. 1	6,732.4	GJ x	$0.747 =	$5,029.1028	6,732.4	GJ x	$0.792 =	$5,332.0608	$0.045	$302.9580	0.11%
14	- Nov. 1 to Apr. 1	0.0	GJ x	$1.076 =	0.0000	0.0	GJ x	$1.141 =	0.0000	$0.065	0.0000	0.00%
15	Rider 3 ESM	6,732.4	GJ x	($0.018) =	(121.1832)	6,732.4	GJ x	($0.005) =	(33.6620)	$0.013	87.5212	0.03%
16	Rider 4 Delivery Rate Refunc	6,732.4	GJ x	($0.003) =	(20.1972)	6,732.4	GJ x	$0.000 =	0.0000	$0.003	20.1972	0.01%
17	Transportation - Interruptible (Delivery Charge Interruptible MTQ				**$4,887.72**				**$5,298.40**		**$410.68**	**0.14%**
18												
19	Non-Standard Charges (not forecast)											
20	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
21												
22	Administration Charge	12	months x	$78.00 =	**$936.00**	12	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
23												
24	Total *(with effective $/GJ rate)*	464,078.2		*$0.617*	**$286,206.92**	464,078.2		*$0.664*	**$308,165.58**	*$0.047*	**$21,958.66**	**7.67%**
25												
26												
27	**COLUMBIA SERVICE - ELKVIEW COAL**											
28	Basic Charge	12	months x	$4,537.00 =	**$54,444.00**	12	months x	$4,537.00 =	**$54,444.00**	$0.00	**$0.00**	**0.00%**
29												
30	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,670.0	GJ x	$1.702 =	**$54,532.08**	2,670.0	GJ x	$1.804 =	**$57,800.16**	$0.102	**$3,268.08**	**2.07%**
31												
32	Delivery Charge - Firm MTQ	631,553.5	GJ x	$0.080 =	$50,524.2800	631,553.5	GJ x	$0.085 =	$53,682.0475	$0.005	$3,157.7675	2.00%
33	Rider 3 ESM	631,553.5	GJ x	($0.007) =	(4,420.8745)	631,553.5	GJ x	$0.000 =	0.0000	$0.007	4,420.8745	2.80%
34	Rider 4 Delivery Rate Refunc	631,553.5	GJ x	($0.003) =	(1,894.6605)	631,553.5	GJ x	$0.000 =	0.0000	$0.003	1,894.6605	1.20%
35	Transportation - Firm (Delivery Charge Firm MTQ)				**$44,208.75**				**$53,682.05**		**$9,473.30**	**6.00%**
36												
37	Delivery Charge - Interruptible MTQ											
38	- Apr. 1 to Nov. 1	0.0	GJ x	$0.187 =	$0.0000	0.0	GJ x	$0.198 =	$0.0000	$0.011	$0.0000	0.00%
39	- Nov. 1 to Apr. 1	14,503.1	GJ x	$0.267 =	3,872.3277	14,503.1	GJ x	$0.283 =	4,104.3773	$0.016	232.0496	0.15%
40	Rider 3 ESM	14,503.1	GJ x	($0.007) =	(101.5217)	14,503.1	GJ x	$0.000 =	0.0000	$0.007	101.5217	0.06%
41	Rider 4 Delivery Rate Refunc	14,503.1	GJ x	($0.003) =	(43.5093)	14,503.1	GJ x	$0.000 =	0.0000	$0.003	43.5093	0.03%
42	Transportation - Interruptible (Delivery Charge Interruptible MTQ				**$3,727.30**				**$4,104.38**		**$377.08**	**0.24%**
43												
44	Non-Standard Charges (not forecast)											
45	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
46												
47	Administration Charge	12	months x	$78.00 =	**$936.00**	12	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
48												
49	Total *(with effective $/GJ rate)*	646,056.6		*$0.244*	**$157,848.13**	646,056.6		*$0.265*	**$170,966.59**	*$0.021*	**$13,118.46**	**8.31%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

RATE SCHEDULE 23 - LARGE COMMERCIAL T-SERVICE

Line No.	Particular	EFFECTIVE APRIL 1, 2009				PROPOSED JANUARY 1, 2010 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bil
2	**LOWER MAINLAND SERVICE AREA**											
3	Basic Charge	12	months x	$132.52 =	**$1,590.24**	12	months x	$132.52 =	**$1,590.24**	$0.00	**$0.00**	**0.00%**
4												
5	Administration Charge	12	months x	$78.00 =	**$936.00**	12	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
6												
7	Delivery Charge	4,100.0	GJ x	$2.136 =	$8,757.6000	4,100.0	GJ x	$2.282 =	$9,356.2000	$0.146	$598.6000	5.50%
8	Rider 3 ESM	4,100.0	GJ x	($0.079) =	(323.9000)	4,100.0	GJ x	($0.023) =	(94.3000)	$0.056	229.6000	2.11%
9	Rider 4 Delivery Rate Refunc	4,100.0	GJ x	($0.022) =	(90.2000)	4,100.0	GJ x	$0.000 =	0.0000	$0.022	90.2000	0.83%
10	Rider 5 RSAM	4,100.0	GJ x	$0.001 =	4.1000	4,100.0	GJ x	($0.053) =	(217.3000)	($0.054)	(221.4000)	-2.04%
11	Transportation - Firm				**$8,347.60**				**$9,044.60**		**$697.00**	**6.41%**
12												
13	Non-Standard Charges (not forecast)											
14	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
15												
16	Total *(with effective $/GJ rate)*	4,100.0		*$2.652*	**$10,873.84**	4,100.0		*$2.822*	**$11,570.84**	*$0.170*	**$697.00**	**6.41%**
17												
18	**INLAND SERVICE AREA**											
19	Basic Charge	12	months x	$132.52 =	**$1,590.24**	12	months x	$132.52 =	**$1,590.24**	$0.00	**$0.00**	**0.00%**
20												
21	Administration Charge	12	months x	$78.00 =	**$936.00**	12	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
22												
23	Delivery Charge	4,700.0	GJ x	$2.136 =	$10,039.2000	4,700.0	GJ x	$2.282 =	$10,725.4000	$0.146	$686.2000	5.67%
24	Rider 3 ESM	4,700.0	GJ x	($0.079) =	(371.3000)	4,700.0	GJ x	($0.023) =	(108.1000)	$0.056	263.2000	2.18%
25	Rider 4 Delivery Rate Refund	4,700.0	GJ x	($0.022) =	(103.4000)	4,700.0	GJ x	$0.000 =	0.0000	$0.022	103.4000	0.85%
26	Rider 5 RSAM	4,700.0	GJ x	$0.001 =	4.7000	4,700.0	GJ x	($0.053) =	(249.1000)	($0.054)	(253.8000)	-2.10%
27	Transportation - Firm				**$9,569.20**				**$10,368.20**		**$799.00**	**6.61%**
28												
29	Non-Standard Charges (not forecast)											
30	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
31												
32	Total *(with effective $/GJ rate)*	4,700.0		*$2.573*	**$12,095.44**	4,700.0		*$2.743*	**$12,894.44**	*$0.170*	**$799.00**	**6.61%**
33												
34	**COLUMBIA SERVICE AREA**											
35	Basic Charge	12	months x	$132.52 =	**$1,590.24**	12	months x	$132.52 =	**$1,590.24**	$0.00	**$0.00**	**0.00%**
36												
37	Administration Charge	12	months x	$78.00 =	**$936.00**	12	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
38												
39	Delivery Charge	4,200.0	GJ x	$2.136 =	$8,971.2000	4,200.0	GJ x	$2.282 =	$9,584.4000	$0.146	$613.2000	5.54%
40	Rider 3 ESM	4,200.0	GJ x	($0.079) =	(331.8000)	4,200.0	GJ x	($0.023) =	(96.6000)	$0.056	235.2000	2.12%
41	Rider 4 Delivery Rate Refunc	4,200.0	GJ x	($0.022) =	(92.4000)	4,200.0	GJ x	$0.000 =	0.0000	$0.022	92.4000	0.83%
42	Rider 5 RSAM	4,200.0	GJ x	$0.001 =	4.2000	4,200.0	GJ x	($0.053) =	(222.6000)	($0.054)	(226.8000)	-2.05%
43	Transportation - Firm				**$8,551.20**				**$9,265.20**		**$714.00**	**6.45%**
44												
45	Non-Standard Charges (not forecast)											
46	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
47												
48	Total *(with effective $/GJ rate)*	4,200.0		*$2.637*	**$11,077.44**	4,200.0		*$2.807*	**$11,791.44**	*$0.170*	**$714.00**	**6.45%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

RATE SCHEDULE 25 - GENERAL FIRM T-SERVICE

Line No.	Particular	EFFECTIVE APRIL 1, 2009				PROPOSED JANUARY 1, 2010 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bil
2	**LOWER MAINLAND SERVICE AREA**											
3	Basic Charge	12	months x	$587.00	= **$7,044.00**	12	months x	$587.00	= **$7,044.00**	$0.00	**$0.00**	**0.00%**
4												
5	Administration Charge	12	months x	$78.00	= **$936.00**	12	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
6												
7	Transportation - Firm Demand	97.2	GJ x	$14.655	= **$17,093.64**	97.2	GJ x	$15.690	= **$18,300.84**	$1.035	**$1,207.20**	**3.45%**
8												
9	Delivery Charge	19,086.2	GJ x	$0.593	= $11,318.1166	19,086.2	GJ x	$0.635	= $12,119.7370	$0.042	$801.6204	2.29%
10	Rider 3 ESM	19,086.2	GJ x	($0.060)	= (1,145.1720)	19,086.2	GJ x	($0.017)	= (324.4654)	$0.043	820.7066	2.34%
11	Rider 4 Delivery Rate Refund	19,086.2	GJ x	($0.012)	= (229.0344)	19,086.2	GJ x	$0.000	= 0.0000	$0.012	229.0344	0.65%
12	Transportation - Firm				**$9,943.91**				**$11,795.27**		**$1,851.36**	**5.29%**
13												
14	Non-Standard Charges (not forecast)											
15	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
16												
17	Total *(with effective $/GJ rate)*	19,086.2		*$1.835*	**$35,017.55**	19,086.2		*$1.995*	**$38,076.11**	*$0.160*	**$3,058.56**	**8.73%**
18												
19	**INLAND SERVICE AREA**											
20	Basic Charge	12	months x	$587.00	= **$7,044.00**	12	months x	$587.00	= **$7,044.00**	$0.00	**$0.00**	**0.00%**
21												
22	Administration Charge	12	months x	$78.00	= **$936.00**	12	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
23												
24	Transportation - Firm Demand	212.6	GJ x	$14.655	= **$37,387.80**	212.6	GJ x	$15.690	= **$40,028.28**	$1.035	**$2,640.48**	**3.97%**
25												
26	Delivery Charge	40,670.5	GJ x	$0.593	= $24,117.6065	40,670.5	GJ x	$0.635	= $25,825.7675	$0.042	$1,708.1610	2.57%
27	Rider 3 ESM	40,670.5	GJ x	($0.060)	= (2,440.2300)	40,670.5	GJ x	($0.017)	= (691.3985)	$0.043	1,748.8315	2.63%
28	Rider 4 Delivery Rate Refund	40,670.5	GJ x	($0.012)	= (488.0460)	40,670.5	GJ x	$0.000	= 0.0000	$0.012	488.0460	0.73%
29	Transportation - Firm				**$21,189.33**				**$25,134.37**		**$3,945.04**	**5.93%**
30												
31	Non-Standard Charges (not forecast)											
32	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
33												
34	Total *(with effective $/GJ rate)*	40,670.5		*$1.636*	**$66,557.13**	40,670.5		*$1.798*	**$73,142.65**	*$0.162*	**$6,585.52**	**9.89%**
35												
36	**COLUMBIA SERVICE**											
37	Basic Charge	12	months x	$587.00	= **$7,044.00**	12	months x	$587.00	= **$7,044.00**	$0.00	**$0.00**	**0.00%**
38												
39	Administration Charge	12	months x	$78.00	= **$936.00**	12	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
40												
41	Transportation - Firm Demand	182.2	GJ x	$14.655	= **$32,041.68**	182.2	GJ x	$15.690	= **$34,304.64**	$1.035	**$2,262.96**	**4.05%**
42												
43	Delivery Charge	30,357.8	GJ x	$0.593	= $18,002.1754	30,357.8	GJ x	$0.635	= $19,277.2030	$0.042	$1,275.0276	2.28%
44	Rider 3 ESM	30,357.8	GJ x	($0.060)	= (1,821.4680)	30,357.8	GJ x	($0.017)	= (516.0826)	$0.043	1,305.3854	2.34%
45	Rider 4 Delivery Rate Refund	30,357.8	GJ x	($0.012)	= (364.2936)	30,357.8	GJ x	$0.000	= 0.0000	$0.012	364.2936	0.65%
46	Transportation - Firm				**$15,816.41**				**$18,761.12**		**$2,944.71**	**5.27%**
47												
48	Non-Standard Charges (not forecast)											
49	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
50												
51	Total *(with effective $/GJ rate)*	30,357.8		*$1.839*	**$55,838.09**	30,357.8		*$2.011*	**$61,045.76**	*$0.172*	**$5,207.67**	**9.33%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

RATE SCHEDULE 27 - INTERRUPTIBLE T-SERVICE

Line No.	Particular	EFFECTIVE APRIL 1, 2009				PROPOSED JANUARY 1, 2010 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bil
2	**LOWER MAINLAND SERVICE AREA**											
3	Basic Charge	12	months x	$880.00	= **$10,560.00**	12	months x	$880.00	= **$10,560.00**	$0.00	**$0.00**	**0.00%**
4												
5	Administration Charge	12	months x	$78.00	= **$936.00**	12	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
6												
7	Delivery Charge	53,957.0	GJ x	$0.990	= $53,417.4300	53,957.0	GJ x	$1.057	= $57,032.5490	$0.067	$3,615.1190	5.78%
8	Rider 3 ESM	53,957.0	GJ x	($0.036)	= (1,942.4520)	53,957.0	GJ x	($0.010)	= (539.5700)	$0.026	1,402.8820	2.24%
9	Rider 4 Delivery Rate Refund	53,957.0	GJ x	($0.008)	= (431.6560)	53,957.0	GJ x	$0.000	= 0.0000	$0.008	431.6560	0.69%
10	Transportation - Interruptible				**$51,043.32**				**$56,492.98**		**$5,449.66**	**8.71%**
11												
12	Non-Standard Charges (not forecast)											
13	UOR, Balancing gas, Backstopping Gas											
14												
15	Total *(with effective $/GJ rate)*	53,957.0		*$1.159*	**$62,539.32**	53,957.0		*$1.260*	**$67,988.98**	*$0.101*	**$5,449.66**	**8.71%**
16												
17												
18	**INLAND SERVICE AREA**											
19	Basic Charge	12	months x	$880.00	= **$10,560.00**	12	months x	$880.00	= **$10,560.00**	$0.00	**$0.00**	**0.00%**
20												
21	Administration Charge	12.0	months x	$78.00	= **$936.00**	12.0	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
22												
23	Delivery Charge	48,903.9	GJ x	$0.990	= $48,414.8610	48,903.9	GJ x	$1.057	= $51,691.4223	$0.067	$3,276.5613	5.67%
24	Rider 3 ESM	48,903.9	GJ x	($0.036)	= (1,760.5404)	48,903.9	GJ x	($0.010)	= (489.0390)	$0.026	1,271.5014	2.20%
25	Rider 4 Delivery Rate Refund	48,903.9	GJ x	($0.008)	= (391.2312)	48,903.9	GJ x	$0.000	= 0.0000	$0.008	391.2312	0.68%
26	Transportation - Interruptible				**$46,263.09**				**$51,202.38**		**$4,939.29**	**8.55%**
27												
28												
29	Non-Standard Charges (not forecast)											
30	UOR, Balancing gas, Backstopping Gas											
31		48,903.9		*$1.181*	**$57,759.09**	48,903.9		*$1.282*	**$62,698.38**	*$0.101*	**$4,939.29**	**8.55%**
32	Total *(with effective $/GJ rate)*											
33												
34												
35	**COLUMBIA SERVICE AREA**											
36	Basic Charge	12	months x	$880.00	= **$10,560.00**	12	months x	$880.00	= **$10,560.00**	$0.00	**$0.00**	**0.00%**
37												
38	Administration Charge	12.0	months x	$78.00	= **$936.00**	12.0	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
39												
40	Delivery Charge	7,733.8	GJ x	$0.990	= $7,656.4620	7,733.8	GJ x	$1.057	= $8,174.6266	$0.067	$518.1646	0.90%
41	Rider 3 ESM	7,733.8	GJ x	($0.036)	= (278.4168)	7,733.8	GJ x	($0.010)	= (77.3380)	$0.026	201.0788	0.35%
42	Rider 4 Delivery Rate Refund	7,733.8	GJ x	($0.008)	= (61.8704)	7,733.8	GJ x	$0.000	= 0.0000	$0.008	61.8704	0.11%
43	Transportation - Interruptible				**$7,316.17**				**$8,097.29**		**$781.12**	**1.35%**
44												
45												
46	Non-Standard Charges (not forecast)											
47	UOR, Balancing gas, Backstopping Gas											
48		7,733.8		*$2.432*	**$18,812.17**	7,733.8		*$2.533*	**$19,593.29**	*$0.101*	**$781.12**	**1.35%**
49	Total *(with effective $/GJ rate)*											

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

TERASEN GAS INC. - INLAND SERVICE AREA (APPLICABLE TO REVELSTOKE CUSTOMERS)
EFFECT ON REVELSTOKE RATE SCHEDULE 1, 2, AND 3 CUSTOMERS' WITH RATE CHANGES
BCUC ORDER NO. G-xx-09

Line No.	PARTICULARS	EXISTING JULY 1, 2009 RATES					PROPOSED JANUARY 1, 2010 RATES					Annual Increase/Decrease		
1	**INLAND SERVICE AREA**	Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bil
2														
3	**Rate 1 - Residential**													
4	Delivery Margin Related Charges													
5	Basic Charge	12	months x	$11.84	=	$142.08	12	months x	$11.84	=	$142.08	$0.00	$0.00	0.00%
6														
7	Delivery Charge	50.0	GJ x	$2.961	=	148.0500	50.0	GJ x	$3.213	=	160.6500	$0.252	12.6000	1.42%
8	Rider 3 ESM	50.0	GJ x	($0.132)	=	(6.6000)	50.0	GJ x	($0.040)	=	(2.0000)	$0.092	4.6000	0.52%
9	Rider 4 Lochburn Land Sale Rebate	50.0	GJ x	($0.035)	=	(1.7500)	50.0	GJ x	$0.000	=	0.00	$0.035	1.7500	0.20%
10	Rider 5 RSAM	50.0	GJ x	$0.001	=	0.0500	50.0	GJ x	($0.053)	=	(2.6500)	($0.054)	(2.7000)	-0.30%
11	Subtotal Delivery Margin Related Charges			$2.795		**$281.83**			$3.120		**$298.08**		**$16.25**	**1.83%**
12														
13	Commodity Related Charges													
14	Midstream Cost Recovery Charge	50.0	GJ x	$0.903	=	$45.1500	50.0	GJ x	$0.903	=	$45.1500	$0.000	$0.0000	0.00%
15	Cost of Gas	50.0	GJ x	$5.962	=	298.1000	50.0	GJ x	$5.962	=	298.1000	$0.000	0.0000	0.00%
16	Rider 1 Propane Surcharge	50.0	GJ x	$5.231	=	261.5500	50.0	GJ x	$5.231	=	261.5500	$0.000	0.0000	0.00%
17	Subtotal Commodity Related Charges			$12.096		**$604.80**			$12.096		**$604.80**		**$0.00**	**0.00%**
18														
19	*Total (with effective $/GJ rate)*	50.0		*$17.733*		**$886.63**	50.0		*$18.058*		**$902.88**	*$0.325*	**$16.25**	**1.83%**
20														
21	**Rate 2 - Small Commercial**													
22	Delivery Margin Related Charges													
23	Basic Charge	12	months x	$24.84	=	$298.08	12	months x	$24.84	=	$298.08	$0.00	$0.00	0.00%
24														
25	Delivery Charge	250.0	GJ x	$2.479	=	619.7500	250.0	GJ x	$2.667	=	666.7500	$0.188	47.0000	1.29%
26	Rider 3 ESM	250.0	GJ x	($0.100)	=	(25.0000)	250.0	GJ x	($0.029)	=	(7.2500)	$0.071	17.7500	0.49%
27	Rider 4 Lochburn Land Sale Rebate	250.0	GJ x	($0.029)	=	(7.2500)	250.0	GJ x	$0.000	=	0.00	$0.029	7.2500	0.20%
28	Rider 5 RSAM	250.0	GJ x	$0.001	=	0.2500	250.0	GJ x	($0.053)	=	(13.2500)	($0.054)	(13.5000)	-0.37%
29	Subtotal Delivery Margin Related Charges			$2.351		**$885.83**			$2.585		**$944.33**		**$58.50**	**1.61%**
30														
31	Commodity Related Charges													
32	Midstream Cost Recovery Charge	250.0	GJ x	$0.907	=	$226.7500	250.0	GJ x	$0.907	=	$226.7500	$0.000	$0.0000	0.00%
33	Cost of Gas	250.0	GJ x	$5.962	=	1,490.5000	250.0	GJ x	$5.962	=	1,490.5000	$0.000	0.0000	0.00%
34	Rider 1 Propane Surcharge	250.0	GJ x	$4.136	=	1,034.0000	250.0	GJ x	$4.136	=	1,034.0000	$0.000	0.0000	0.00%
35	Subtotal Commodity Related Charges			$11.005		**$2,751.25**			$11.005		**$2,751.25**		**$0.00**	**0.00%**
36														
37	*Total (with effective $/GJ rate)*	250.0		*$14.548*		**$3,637.08**	250.0		*$14.782*		**$3,695.58**	*$0.234*	**$58.50**	**1.61%**
38														
39	**Rate 3 - Large Commercial**													
40	Delivery Margin Related Charges													
41	Basic Charge	12	months x	$132.52	=	$1,590.24	12	months x	$132.52	=	$1,590.24	$0.00	$0.00	0.00%
42														
43	Delivery Charge	4,500.0	GJ x	$2.136	=	9,612.0000	4,500.0	GJ x	$2.282	=	10,269.0000	$0.146	657.0000	1.09%
44	Rider 3 ESM	4,500.0	GJ x	($0.079)	=	(355.5000)	4,500.0	GJ x	($0.023)	=	(103.5000)	$0.056	252.0000	0.42%
45	Rider 4 Lochburn Land Sale Rebate	4,500.0	GJ x	($0.021)	=	(94.5000)	4,500.0	GJ x	$0.000	=	0.00	$0.021	94.5000	0.16%
46	Rider 5 RSAM	4,500.0	GJ x	$0.001	=	4.5000	4,500.0	GJ x	($0.053)	=	(238.5000)	($0.054)	(243.0000)	-0.40%
47	Subtotal Delivery Margin Related Charges			$2.037		**$10,756.74**			$2.206		**$11,517.24**		**$760.50**	**1.26%**
48														
49	Commodity Related Charges													
50	Midstream Cost Recovery Charge	4,500.0	GJ x	$0.796	=	$3,582.0000	4,500.0	GJ x	$0.796	=	$3,582.0000	$0.000	$0.0000	0.00%
51	Cost of Gas	4,500.0	GJ x	$5.962	=	26,829.0000	4,500.0	GJ x	$5.962	=	26,829.0000	$0.000	0.0000	0.00%
52	Rider 1 Propane Surcharge	4,500.0	GJ x	$4.247	=	19,111.5000	4,500.0	GJ x	$4.247	=	19,111.5000	$0.000	0.0000	0.00%
53	Subtotal Commodity Related Charges			$11.005		**$49,522.50**			$11.005		**$49,522.50**		**$0.00**	**0.00%**
54														
55	*Total (with effective $/GJ rate)*	4,500.0		*$13.395*		**$60,279.24**	4,500.0		*$13.564*		**$61,039.74**	*$0.169*	**$760.50**	**1.26%**

Notes: Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations.
Slight differences in totals due to rounding

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2011 RATES
BCUC ORDER NO. G-xx-09

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE	EXISTING JULY 1, 2009 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2011 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$11.84**	**$11.84**	**$11.84**	**$0.00**	**$0.00**	**$0.00**	**$11.84**	**$11.84**	**$11.84**
3										
4	Delivery Charge per GJ	$2.961	$2.961	$2.961	$0.452	$0.452	$0.452	$3.413	$3.413	$3.413
5	Rider 3 ESM	($0.132)	($0.132)	($0.132)	$0.086	$0.086	$0.086	($0.046)	($0.046)	($0.046)
6	Rider 4 Delivery Rate Refund	($0.035)	($0.035)	($0.035)	$0.035	$0.035	$0.035	$0.000	$0.000	$0.000
7	Rider 5 RSAM	$0.001	$0.001	$0.001	($0.053)	($0.053)	($0.053)	($0.052)	($0.052)	($0.052)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.795**	**$2.795**	**$2.795**	**$0.520**	**$0.520**	**$0.520**	**$3.315**	**$3.315**	**$3.315**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$0.942	$0.903	$0.981	$0.000	$0.000	$0.000	$0.942	$0.903	$0.981
13	Rider 8 Unbundling Recovery	$0.073	$0.073	$0.073	$0.000	$0.000	$0.000	$0.073	$0.073	$0.073
14	Subtotal **Midstream Related Charges per GJ**	**$1.015**	**$0.976**	**$1.054**	**$0.000**	**$0.000**	**$0.000**	**$1.015**	**$0.976**	**$1.054**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$5.962**	**$5.962**	**$5.962**	**$0.000**	**$0.000**	**$0.000**	**$5.962**	**$5.962**	**$5.962**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$5.231			$0.000			$5.231	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$12.096**			**$0.000**			**$12.096**	
23	per GJ (Includes Rider 1, excludes Riders 8)									

Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE	EXISTING JULY 1, 2009 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2011 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$24.84**	**$24.84**	**$24.84**	**$0.00**	**$0.00**	**$0.00**	**$24.84**	**$24.84**	**$24.84**
3										
4	Delivery Charge per GJ	$2.479	$2.479	$2.479	$0.335	$0.335	$0.335	$2.814	$2.814	$2.814
5	Rider 3 ESM	($0.100)	($0.100)	($0.100)	$0.066	$0.066	$0.066	($0.034)	($0.034)	($0.034)
6	Rider 4 Delivery Rate Refund	($0.029)	($0.029)	($0.029)	$0.029	$0.029	$0.029	$0.000	$0.000	$0.000
7	Rider 5 RSAM	$0.001	$0.001	$0.001	($0.053)	($0.053)	($0.053)	($0.052)	($0.052)	($0.052)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.351**	**$2.351**	**$2.351**	**$0.377**	**$0.377**	**$0.377**	**$2.728**	**$2.728**	**$2.728**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$0.947	$0.907	$0.986	$0.000	$0.000	$0.000	$0.947	$0.907	$0.986
13	Rider 8 Unbundling Recovery	($0.021)	($0.021)	($0.021)	$0.000	$0.000	$0.000	($0.021)	($0.021)	($0.021)
14	Subtotal **Midstream Related Charges per GJ**	**$0.926**	**$0.886**	**$0.965**	**$0.000**	**$0.000**	**$0.000**	**$0.926**	**$0.886**	**$0.965**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$5.962**	**$5.962**	**$5.962**	**$0.000**	**$0.000**	**$0.000**	**$5.962**	**$5.962**	**$5.962**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$4.136			$0.000			$4.136	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$11.005**			**$0.000**			**$11.005**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE	EXISTING JULY 1, 2009 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2011 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	**$132.52**	**$132.52**	**$132.52**	**$0.00**	**$0.00**	**$0.00**	**$132.52**	**$132.52**	**$132.52**
3										
4	Delivery Charge per GJ	$2.136	$2.136	$2.136	$0.261	$0.261	$0.261	$2.397	$2.397	$2.397
5	Rider 3 ESM	($0.079)	($0.079)	($0.079)	$0.052	$0.052	$0.052	($0.027)	($0.027)	($0.027)
6	Rider 4 Delivery Rate Refund	($0.021)	($0.021)	($0.021)	$0.021	$0.021	$0.021	$0.000	$0.000	$0.000
7	Rider 5 RSAM	$0.001	$0.001	$0.001	($0.053)	($0.053)	($0.053)	($0.052)	($0.052)	($0.052)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.037**	**$2.037**	**$2.037**	**$0.281**	**$0.281**	**$0.281**	**$2.318**	**$2.318**	**$2.318**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$0.830	$0.796	$0.873	$0.000	$0.000	$0.000	$0.830	$0.796	$0.873
13	Rider 8 Unbundling Recovery	($0.021)	($0.021)	($0.021)	$0.000	$0.000	$0.000	($0.021)	($0.021)	($0.021)
14	Subtotal **Midstream Related Charges per GJ**	**$0.809**	**$0.775**	**$0.852**	**$0.000**	**$0.000**	**$0.000**	**$0.809**	**$0.775**	**$0.852**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$5.962**	**$5.962**	**$5.962**	**$0.000**	**$0.000**	**$0.000**	**$5.962**	**$5.962**	**$5.962**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$4.247			$0.000			$4.247	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$11.005**			**$0.000**			**$11.005**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

Line No.	RATE SCHEDULE 4: SEASONAL SERVICE	EFFECTIVE APRIL 1, 2009			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2011 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$439.00	$439.00	$439.00	$0.00	$0.00	$0.00	$439.00	$439.00	$439.00
3										
4	**Delivery Charge per GJ**									
5	(a) Off-Peak Period	$0.762	$0.762	$0.762	$0.135	$0.135	$0.135	$0.897	$0.897	$0.897
6	(b) Extension Period	$1.539	$1.539	$1.539	$0.135	$0.135	$0.135	$1.674	$1.674	$1.674
7										
8	**Rider 3 ESM**	($0.061)	($0.061)	($0.061)	$0.050	$0.050	$0.050	($0.011)	($0.011)	($0.011)
9	**Rider 4 Delivery Rate Refund**	($0.001)	($0.001)	($0.001)	$0.001	$0.001	$0.001	$0.000	$0.000	$0.000
10										
11	Commodity Related Charges									
12	**Commodity Cost Recovery Charge**									
13	(a) Off-Peak Period	$5.962	$5.962	$5.962	$0.000	$0.000	$0.000	$5.962	$5.962	$5.962
14	(b) Extension Period	$5.962	$5.962	$5.962	$0.000	$0.000	$0.000	$5.962	$5.962	$5.962
15										
16	**Midstream Cost Recovery Charge per GJ**									
17	(a) Off-Peak Period	$0.670	$0.644	$0.720	$0.000	$0.000	$0.000	$0.670	$0.644	$0.720
18	(b) Extension Period	$0.670	$0.644	$0.720	$0.000	$0.000	$0.000	$0.670	$0.644	$0.720
19										
20										
21	Subtotal Off -Peak Commodity Related Charges per GJ									
22	(a) Off-Peak Period	$6.632	$6.606	$6.682	$0.000	$0.000	$0.000	$6.632	$6.606	$6.682
23	(b) Extension Period	$6.632	$6.606	$6.682	$0.000	$0.000	$0.000	$6.632	$6.606	$6.682
24										
25										
26										
27	Unauthorized Gas Charge per gigajoule	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
28	during peak period									
29										
30										
31	Total Variable Cost per gigajoule between									
32	(a) Off-Peak Period	$7.332	$7.306	$7.382	$0.186	$0.186	$0.186	$7.518	$7.492	$7.568
33	(b) Extension Period	$8.109	$8.083	$8.159	$0.186	$0.186	$0.186	$8.295	$8.269	$8.345

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2011 RATES
BCUC ORDER NO. G-xx-09

	RATE SCHEDULE 5 GENERAL FIRM SERVICE	**EFFECTIVE APRIL 1, 2009**			**DELIVERY MARGIN RELATED CHARGES CHANGES**			**PROPOSED JANUARY 1, 2011 RATES**		
Line No.	Particulars	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$587.00	$587.00	$587.00	$0.00	$0.00	$0.00	$587.00	$587.00	$587.00
3										
4	**Demand Charge per gigajoule**	$14.655	$14.655	$14.655	$1.849	$1.849	$1.849	$16.504	$16.504	$16.504
5										
6	**Delivery Charge per GJ**	$0.593	$0.593	$0.593	$0.075	$0.075	$0.075	$0.668	$0.668	$0.668
7										
8	**Rider 3 ESM**	($0.060)	($0.060)	($0.060)	$0.040	$0.040	$0.040	($0.020)	($0.020)	($0.020)
9	**Rider 4 Delivery Rate Refund**	($0.018)	($0.018)	($0.018)	$0.018	$0.018	$0.018	$0.000	$0.000	$0.000
10										
11										
12	Commodity Related Charges									
13	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$5.962	$5.962	$5.962	$0.000	$0.000	$0.000	$5.962	$5.962	$5.962
14	**Midstream Cost Recovery Charge per GJ**	$0.670	$0.644	$0.720	$0.000	$0.000	$0.000	$0.670	$0.644	$0.720
15	Subtotal Commodity Related Charges per GJ	**$6.632**	**$6.606**	**$6.682**	**$0.000**	**$0.000**	**$0.000**	**$6.632**	**$6.606**	**$6.682**
16										
17										
18										
19	Total Variable Cost per gigajoule	$7.147	$7.121	$7.197	$0.133	$0.133	$0.133	$7.280	$7.254	$7.330

Line No.	**RATE SCHEDULE 6: NGV - STATIONS** Particulars	**EFFECTIVE APRIL 1, 2009** Lower Mainland	Inland	Columbia	**DELIVERY MARGIN RELATED CHARGES CHANGES** Lower Mainland	Inland	Columbia	**PROPOSED JANUARY 1, 2011 RATES** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$61.00	$61.00	$61.00	$0.00	$0.00	$0.00	$61.00	$61.00	$61.00
3										
4	**Delivery Charge per GJ**	$3.398	$3.398	$3.398	$0.356	$0.356	$0.356	$3.754	$3.754	$3.754
5										
6	**Rider 3 ESM**	($0.110)	($0.110)	($0.110)	$0.077	$0.077	$0.077	($0.033)	($0.033)	($0.033)
7	**Rider 4 Delivery Rate Refund**	($0.019)	($0.019)	($0.019)	$0.019	$0.019	$0.019	$0.000	$0.000	$0.000
8										
9										
10	Commodity Related Charges									
11	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$5.962	$5.962	$5.962	$0.000	$0.000	$0.000	$5.962	$5.962	$5.962
12	**Midstream Cost Recovery Charge per GJ**	$0.471	$0.446	$0.446	$0.000	$0.000	$0.000	$0.471	$0.446	$0.446
13	Subtotal Commodity Related Charges per GJ	**$6.433**	**$6.408**	**$6.408**	**$0.000**	**$0.000**	**$0.000**	**$6.433**	**$6.408**	**$6.408**
14										
15										
16	Total Variable Cost per gigajoule	$9.702	$9.677	$9.677	$0.452	$0.452	$0.452	$10.154	$10.129	$10.129

Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES	EFFECTIVE APRIL 1, 2009			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2011 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$880.00	$880.00	$880.00	$0.00	$0.00	$0.00	$880.00	$880.00	$880.00
3										
4	**Delivery Charge per GJ**	$0.990	$0.990	$0.990	$0.120	$0.120	$0.120	$1.110	$1.110	$1.110
5										
6	**Rider 3 ESM**	($0.036)	($0.036)	($0.036)	$0.024	$0.024	$0.024	($0.012)	($0.012)	($0.012)
7	**Rider 4 Delivery Rate Refund**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
8										
9	Commodity Related Charges									
10	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$5.962	$5.962	$5.962	$0.000	$0.000	$0.000	$5.962	$5.962	$5.962
11	**Midstream Cost Recovery Charge per GJ**	$0.670	$0.644	$0.720	$0.000	$0.000	$0.000	$0.670	$0.644	$0.720
12	Subtotal Commodity Related Charges per GJ	**$6.632**	**$6.606**	**$6.682**	**$0.000**	**$0.000**	**$0.000**	**$6.632**	**$6.606**	**$6.682**
13										
14										
15										
16	Charges per gigajoule for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17										
18										
19										
20										
21										
22	Total Variable Cost per gigajoule	$7.586	$7.560	$7.636	$0.144	$0.144	$0.144	$7.730	$7.704	$7.780

Line No.	RATE SCHEDULE 22: LARGE INDUSTRIAL T-SERVICE	EFFECTIVE APRIL 1, 2009			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2011 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$3,664.00	$3,664.00	$3,664.00	$0.00	$0.00	$0.00	$3,664.00	$3,664.00	$3,664.00
2										
3	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.733	$0.733	$0.733	$0.080	$0.080	$0.080	$0.813	$0.813	$0.813
4										
5	**Rider 3 ESM**	($0.023)	($0.023)	($0.023)	$0.015	$0.015	$0.015	($0.008)	($0.008)	($0.008)
6	**Rider 4 Delivery Rate Refund**	($0.005)	($0.005)	($0.005)	$0.005	$0.005	$0.005	$0.000	$0.000	$0.000
7										
8		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
9	**Charges per gigajoule for UOR Gas**									
10										
11										
12	**Demand Surcharge per gigajoule**	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00	$17.00	$17.00	$17.00
13										
14										
15	**Balancing Service per gigajoule**									
16	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.30	n/a	$0.00	$0.00	n/a	$0.30	$0.30	n/a
17	(b) between and including Nov. 1 and Mar. 31	$1.10	$1.10	n/a	$0.00	$0.00	n/a	$1.10	$1.10	n/a
18										
19								Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
20	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.								
21										
22										
23										
24	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
25										
26										
27										
28										
29	Total Variable Cost per gigajoule	$0.705	$0.705	$0.705	$0.100	$0.100	$0.100	$0.805	$0.805	$0.805

Line No.	**RATE SCHEDULE 22A: LARGE INDUSTRIAL T-SERVICE** Particulars	**EFFECTIVE APRIL 1, 2009**	**DELIVERY MARGIN RELATED CHARGES CHANGES**	**PROPOSED JANUARY 1, 2011 RATES**
	(1)	(2)	(3)	(4)
1	**INLAND SERVICE AREA**			
2				
3	**Basic Charge per Month**	$4,810.00	$0.00	$4,810.00
4				
5	**Delivery Charge per gigajoule - Firm**			
6	(a) Firm DTQ	$11.765	$1.306	$13.071
7	(b) Firm MTQ	$0.082	$0.009	$0.091
8				
9	**Delivery Charge per gigajoule - Interr MTQ**	$0.939	$0.092	$1.031
10				
11	**Rider 3 ESM**	($0.022)	$0.014	($0.008)
12	**Rider 4 Delivery Rate Refund**	($0.003)	$0.003	$0.000
13				
14				
15	**Charges per gigajoule for UOR Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
16				
17				
18	**Demand Surchage per gigajoule**	$17.00	$0.00	$17.00
19				
20	**Balancing Service per gigajoule**			
21	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.00	$0.30
22	(b) between and including Nov. 1 and Mar. 31	$1.10	$0.00	$1.10
23				
24				
25	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
26				
27				
28	**Replacement Gas**	Sumas Daily Price		Sumas Daily Price
29		plus 20 Percent		plus 20 Percent
30				
31	**Administration Charge per Month**	$78.00	$0.00	$78.00
32				
33	Total Variable Cost per gigajoule			
34	(a) Firm MTQ	$0.057	$0.026	$0.083
35	(b) Interruptible MTQ	$0.914	$0.109	$1.023

TERASEN GAS INC.
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RATE SCHEDULE 22B:
LARGE INDUSTRIAL T-SERVICE

Line No.	Particulars	EFFECTIVE APRIL 1, 2009 Columbia Except Elkview	EFFECTIVE APRIL 1, 2009 Elkview Coal	DELIVERY MARGIN RELATED CHARGES CHANGES Columbia Except Elkview	DELIVERY MARGIN RELATED CHARGES CHANGES Elkview Coal	PROPOSED JANUARY 1, 2011 RATES Columbia Except Elkview	PROPOSED JANUARY 1, 2011 RATES Elkview Coal
	(1)	-2	(3)	(4)	(5)	-6	-7
1	**COLUMBIA SERVICE AREA**						
2							
3	**Basic Charge per Month**	$4,537.00	$4,537.00	$0.00	$0.00	$4,537.00	$4,537.00
4							
5	**Delivery Charge per gigajoule - Firm**						
6	(a) Firm DTQ	$7.496	$1.702	$0.800	$0.182	$8.296	$1.884
7	(b) Firm MTQ	$0.080	$0.080	$0.009	$0.009	$0.089	$0.089
8							
9	**Delivery Charge per gigajoule - Interr MTQ**						
10	(a) between and including Apr. 1 and Oct. 31	$0.747	$0.187	$0.080	$0.020	$0.827	$0.207
11	(b) between and including Nov. 1 and Mar.31	$1.076	$0.267	$0.115	$0.028	$1.191	$0.295
12							
13	**Rider 3 ESM**	($0.018)	($0.007)	$0.013	$0.005	($0.005)	($0.002)
14	**Rider 4 Delivery Rate Refund**	($0.003)	($0.003)	$0.003	$0.003	$0.000	$0.000
15							
16		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
17	**Charges per gigajoule for UOR Gas**						
18							
19							
20	**Demand Surchage per gigajoule**	$17.00	$17.00	$0.00	$0.00	$17.00	$17.00
21							
22		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
23	**Charges per gigajoule for Backstopping Gas**						
24							
25							
26	**Administration Charge per Month**	$78.00	$78.00	$0.00	$0.00	$78.00	$78.00
27							
28							
29	Total Variable Cost per gigajoule						
30	(a) Firm MTQ	$0.059	$0.070	$0.025	$0.017	$0.084	$0.087
31	(b) Interruptible MTQ - Summer	$0.726	$0.177	$0.096	$0.028	$0.822	$0.205
32	- Winter	$1.055	$0.257	$0.131	$0.036	$1.186	$0.293

Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE Particulars	EFFECTIVE APRIL 1, 2009 Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2011 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$132.52	$132.52	$132.52	$0.00	$0.00	$0.00	$132.52	$132.52	$132.52
2										
3	**Delivery Charge per gigajoule**	$2.136	$2.136	$2.136	$0.261	$0.261	$0.261	$2.397	$2.397	$2.397
4										
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8	**Sales**									
9	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per gigajoule for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 3 ESM**	($0.079)	($0.079)	($0.079)	$0.052	$0.052	$0.052	($0.027)	($0.027)	($0.027)
15	**Rider 4 Delivery Rate Refund**	($0.022)	($0.022)	($0.022)	$0.022	$0.022	$0.022	$0.000	$0.000	$0.000
16	**Rider 5 RSAM**	$0.001	$0.001	$0.001	($0.053)	($0.053)	($0.053)	($0.052)	($0.052)	($0.052)
17										
18										
19										
20	Total Variable Cost per gigajoule	$2.036	$2.036	$2.036	$0.282	$0.282	$0.282	$2.318	$2.318	$2.318

TERASEN GAS INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
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Line No.	RATE SCHEDULE 25 GENERAL FIRM T-SERVICE	EFFECTIVE APRIL 1, 2009			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2011 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$587.00	$587.00	$587.00	$0.00	$0.00	$0.00	$587.00	$587.00	$587.00
2										
3	**Demand Charge per gigajoule**	$14.655	$14.655	$14.655	$1.849	$1.849	$1.849	$16.504	$16.504	$16.504
4										
5	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.593	$0.593	$0.593	$0.075	$0.075	$0.075	$0.668	$0.668	$0.668
6										
7	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
8										
9										
10	**Sales**									
11	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per gigajoule for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per gigajoule for UOR Gas									
15										
16										
17	**Rider 3 ESM**	($0.060)	($0.060)	($0.060)	$0.040	$0.040	$0.040	($0.020)	($0.020)	($0.020)
18	**Rider 4 Delivery Rate Refund**	($0.012)	($0.012)	($0.012)	$0.012	$0.012	$0.012	$0.000	$0.000	$0.000
19										
20										
21										
22	Total Variable Cost per gigajoule	$0.521	$0.521	$0.521	$0.127	$0.127	$0.127	$0.648	$0.648	$0.648

Line No.	RATE SCHEDULE 27: INTERRUPTIBLE T-SERVICE Particulars	EFFECTIVE APRIL 1, 2009 Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2011 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$880.00	$880.00	$880.00	$0.00	$0.00	$0.00	$880.00	$880.00	$880.00
2										
3										
4	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.990	$0.990	$0.990	$0.120	$0.120	$0.120	$1.110	$1.110	$1.110
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8										
9	**Sales**									
10	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
11	(b) Charge per gigajoule for Backstopping Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
17	**Rider 3 ESM**	($0.036)	($0.036)	($0.036)	$0.024	$0.024	$0.024	($0.012)	($0.012)	($0.012)
18	**Rider 4 Delivery Rate Refund**	($0.008)	($0.008)	($0.008)	$0.008	$0.008	$0.008	$0.000	$0.000	$0.000
19										
20										
21										
22	Total Variable Cost per gigajoule	$0.946	$0.946	$0.946	$0.152	$0.152	$0.152	$1.098	$1.098	$1.098

RATE SCHEDULE 1 - RESIDENTIAL SERVICE

Line No.	Particular	EXISTING JULY 1, 2009 RATES Volume	Rate	Annual $	PROPOSED JANUARY 1, 2011 RATES Volume	Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bil
1	**LOWER MAINLAND SERVICE AREA**									
2	Delivery Margin Related Charges									
3	Basic Charge	12 months x	$11.84 =	$142.08	12 months x	$11.84 =	$142.08	$0.00	$0.00	0.00%
4										
5	Delivery Charge	95.0 GJ x	$2.961 =	281.2950	95.0 GJ x	$3.413 =	324.2350	$0.452	42.9400	4.01%
6	Rider 3 ESM	95.0 GJ x	($0.132) =	(12.5400)	95.0 GJ x	($0.046) =	(4.3700)	$0.086	8.1700	0.76%
7	Rider 4 Delivery Rate Refund	95.0 GJ x	($0.035) =	(3.3250)	95.0 GJ x	$0.000 =	0.00	$0.035	3.3250	0.31%
8	Rider 5 RSAM	95.0 GJ x	$0.001 =	0.0950	95.0 GJ x	($0.052) =	(4.9400)	($0.053)	(5.0350)	-0.47%
9	Subtotal Delivery Margin Related Charges			**$407.61**			**$457.01**		**$49.40**	**4.61%**
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge	95.0 GJ x	$0.942 =	$89.4900	95.0 GJ x	$0.942 =	$89.4900	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	95.0 GJ x	$0.073 =	6.9350	95.0 GJ x	$0.073 =	6.9350	$0.000	0.0000	0.00%
14	Midstream Related Charges Subtotal			$96.43			$96.43		$0.00	0.00%
15										
16	Cost of Gas (Commodity Cost Recovery Charge)	95.0 GJ x	$5.962 =	$566.39	95.0 GJ x	$5.962 =	$566.39	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges			**$662.82**			**$662.82**		**$0.00**	**0.00%**
18										
19	Total *(with effective $/GJ rate)*	95.0	*$11.268*	**$1,070.43**	95.0	*$11.788*	**$1,119.83**	*$0.520*	**$49.40**	**4.61%**
20										
21	**INLAND SERVICE AREA**									
22	Delivery Margin Related Charges									
23	Basic Charge	12 months x	$11.84 =	$142.08	12 months x	$11.84 =	$142.08	$0.00	$0.00	0.00%
24										
25	Delivery Charge	75.0 GJ x	$2.961 =	222.0750	75.0 GJ x	$3.413 =	255.9750	$0.452	33.9000	3.89%
26	Rider 3 ESM	75.0 GJ x	($0.132) =	(9.9000)	75.0 GJ x	($0.046) =	(3.4500)	$0.086	6.4500	0.74%
27	Rider 4 Delivery Rate Refund	75.0 GJ x	($0.035) =	(2.6250)	75.0 GJ x	$0.000 =	0.00	$0.035	2.6250	0.30%
28	Rider 5 RSAM	75.0 GJ x	$0.001 =	0.0750	75.0 GJ x	($0.052) =	(3.9000)	($0.053)	(3.9750)	-0.46%
29	Subtotal Delivery Margin Related Charges			**$351.71**			**$390.71**		**$39.00**	**4.47%**
30										
31	Commodity Related Charges									
32	Midstream Cost Recovery Charge	75.0 GJ x	$0.903 =	$67.7250	75.0 GJ x	$0.903 =	$67.7250	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	75.0 GJ x	$0.073 =	5.4750	75.0 GJ x	$0.073 =	5.4750	$0.000	0.0000	0.00%
34	Midstream Related Charges Subtotal			$73.20			$73.20		$0.00	0.00%
35										
36	Cost of Gas (Commodity Cost Recovery Charge)	75.0 GJ x	$5.962 =	$447.15	75.0 GJ x	$5.962 =	$447.15	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges			**$520.35**			**$520.35**		**$0.00**	**0.00%**
38										
39	Total *(with effective $/GJ rate)*	75.0	*$11.627*	**$872.06**	75.0	*$12.147*	**$911.06**	*$0.520*	**$39.00**	**4.47%**
40										
41	**COLUMBIA SERVICE AREA**									
42	Delivery Margin Related Charges									
43	Basic Charge	12 months x	$11.84 =	$142.08	12 months x	$11.84 =	$142.08	$0.00	$0.00	0.00%
44										
44	Delivery Charge	80.0 GJ x	$2.961 =	236.8800	80.0 GJ x	$3.413 =	273.0400	$0.452	36.1600	3.90%
45	Rider 3 ESM	80.0 GJ x	($0.132) =	(10.5600)	80.0 GJ x	($0.046) =	(3.6800)	$0.086	6.8800	0.74%
46	Rider 4 Delivery Rate Refund	80.0 GJ x	($0.035) =	(2.8000)	80.0 GJ x	$0.000 =	0.00	$0.035	2.8000	0.30%
47	Rider 5 RSAM	80.0 GJ x	$0.001 =	0.0800	80.0 GJ x	($0.052) =	(4.1600)	($0.053)	(4.2400)	-0.46%
48	Subtotal Delivery Margin Related Charges			**$365.68**			**$407.28**		**$41.60**	**4.49%**
49										
50	Commodity Related Charges									
51	Midstream Cost Recovery Charge	80.0 GJ x	$0.981 =	$78.4800	80.0 GJ x	$0.981 =	$78.4800	$0.000	$0.0000	0.00%
52	Rider 8 Unbundling Recovery	80.0 GJ x	$0.073 =	5.8400	80.0 GJ x	$0.073 =	5.8400	$0.000	0.0000	0.00%
53	Midstream Related Charges Subtotal			$84.32			$84.32		$0.00	0.00%
54										
55	Cost of Gas (Commodity Cost Recovery Charge)	80.0 GJ x	$5.962	$476.96	80.0 GJ x	$5.962 =	$476.96	$0.000	$0.00	0.00%
56	Subtotal Commodity Related Charges			**$561.28**	80.0		**$561.28**		**$0.00**	**0.00%**
57										
58	Total *(with effective $/GJ rate)*	80.0	*$11.587*	**$926.96**	80.0	*$12.107*	**$968.56**	*$0.520*	**$41.60**	**4.49%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

TERASEN GAS INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO. G-xx-09

RATE SCHEDULE 2 -SMALL COMMERCIAL SERVICE

Line No.	Particular	EXISTING JULY 1, 2009 RATES Volume	Rate	Annual $	PROPOSED JANUARY 1, 2011 RATES Volume	Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**									
2	Delivery Margin Related Charges									
3	Basic Charge	12 months x	$24.84 =	$298.08	12 months x	$24.84 =	$298.08	$0.00	$0.00	0.00%
4										
5	Delivery Charge	300.0 GJ x	$2.479 =	743.7000	300.0 GJ x	$2.814 =	844.2000	$0.335	100.5000	3.27%
6	Rider 3 ESM	300.0 GJ x	($0.100) =	(30.0000)	300.0 GJ x	($0.034) =	(10.2000)	$0.066	19.8000	0.64%
7	Rider 4 Delivery Rate Refund	300.0 GJ x	($0.029) =	(8.7000)	300.0 GJ x	$0.000 =	0.00	$0.029	8.7000	0.28%
8	Rider 5 RSAM	300.0 GJ x	$0.001 =	0.3000	300.0 GJ x	($0.052) =	(15.6000)	($0.053)	(15.9000)	-0.52%
9	Subtotal Delivery Margin Related Charges			**$1,003.38**			**$1,116.48**		**$113.10**	**3.68%**
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge	300.0 GJ x	$0.947 =	$284.1000	300.0 GJ x	$0.947 =	$284.1000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	300.0 GJ x	($0.021) =	(6.3000)	300.0 GJ x	($0.021) =	(6.3000)	$0.000	0.0000	0.00%
14	Midstream Related Charges Subtotal			$277.80			$277.80		$0.00	0.00%
15										
16	Cost of Gas (Commodity Cost Recovery Charge)	300.0 GJ x	$5.962 =	$1,788.60	300.0 GJ x	$5.962 =	$1,788.60	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges			**$2,066.40**			**$2,066.40**		**$0.00**	**0.00%**
18										
19	Total *(with effective $/GJ rate)*	300.0	*$10.233*	**$3,069.78**	300.0	*$10.610*	**$3,182.88**	*$0.377*	**$113.10**	**3.68%**
20										
21	**INLAND SERVICE AREA**									
22	Delivery Margin Related Charges									
23	Basic Charge	12 months x	$24.84 =	$298.08	12 months x	$24.84 =	$298.08	$0.00	$0.00	0.00%
24										
25	Delivery Charge	250.0 GJ x	$2.479 =	619.7500	250.0 GJ x	$2.814 =	703.5000	$0.335	83.7500	3.22%
26	Rider 3 ESM	250.0 GJ x	($0.100) =	(25.0000)	250.0 GJ x	($0.034) =	(8.5000)	$0.066	16.5000	0.64%
27	Rider 4 Delivery Rate Refund	250.0 GJ x	($0.029) =	(7.2500)	250.0 GJ x	$0.000 =	0.00	$0.029	7.2500	0.28%
28	Rider 5 RSAM	250.0 GJ x	$0.001 =	0.2500	250.0 GJ x	($0.052) =	(13.0000)	($0.053)	(13.2500)	-0.51%
29	Subtotal Delivery Margin Related Charges			**$885.83**			**$980.08**		**$94.25**	**3.63%**
30										
31	Commodity Related Charges									
32	Midstream Cost Recovery Charge	250.0 GJ x	$0.907 =	$226.7500	250.0 GJ x	$0.907 =	$226.7500	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	250.0 GJ x	($0.021) =	(5.2500)	250.0 GJ x	($0.021) =	(5.2500)	$0.000	0.0000	0.00%
34	Midstream Related Charges Subtotal			$221.50			$221.50		$0.00	0.00%
35										
36	Cost of Gas (Commodity Cost Recovery Charge)	250.0 GJ x	$5.962 =	$1,490.50	250.0 GJ x	$5.962 =	$1,490.50	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges			**$1,712.00**			**$1,712.00**		**$0.00**	**0.00%**
38										
39	Total *(with effective $/GJ rate)*	250.0	*$10.391*	**$2,597.83**	250.0	*$10.768*	**$2,692.08**	*$0.377*	**$94.25**	**3.63%**
40										
41	**COLUMBIA SERVICE AREA**									
42	Delivery Margin Related Charges									
43	Basic Charge	12 months x	$24.84 =	$298.08	12 months x	$24.84 =	$298.08	$0.00	$0.00	0.00%
44										
45	Delivery Charge	320.0 GJ x	$2.479 =	793.2800	320.0 GJ x	$2.814 =	900.4800	$0.335	107.2000	3.28%
46	Rider 3 ESM	320.0 GJ x	($0.100) =	(32.0000)	320.0 GJ x	($0.034) =	(10.8800)	$0.066	21.1200	0.65%
47	Rider 4 Delivery Rate Refund	320.0 GJ x	($0.029) =	(9.2800)	320.0 GJ x	$0.000 =	0.00	$0.029	9.2800	0.28%
48	Rider 5 RSAM	320.0 GJ x	$0.001 =	0.3200	320.0 GJ x	($0.052) =	(16.6400)	($0.053)	(16.9600)	-0.52%
49	Subtotal Delivery Margin Related Charges			**$1,050.40**			**$1,171.04**		**$120.64**	**3.69%**
50										
51	Commodity Related Charges									
52	Midstream Cost Recovery Charge	320.0 GJ x	$0.986 =	$315.5200	320.0 GJ x	$0.986 =	$315.5200	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	320.0 GJ x	($0.021) =	(6.7200)	320.0 GJ x	($0.021) =	(6.7200)	$0.000	0.0000	0.00%
54	Midstream Related Charges Subtotal			$308.80			$308.80		$0.00	0.00%
55										
56	Cost of Gas (Commodity Cost Recovery Charge)	320.0 GJ x	$5.962 =	$1,907.84	320.0 GJ x	$5.962 =	$1,907.84	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges			**$2,216.64**			**$2,216.64**		**$0.00**	**0.00%**
58										
59	Total *(with effective $/GJ rate)*	320.0	*$10.210*	**$3,267.04**	320.0	*$10.587*	**$3,387.68**	*$0.377*	**$120.64**	**3.69%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

RATE SCHEDULE 3 - LARGE COMMERCIAL SERVICE

Line No.	Particular	EXISTING JULY 1, 2009 RATES					PROPOSED JANUARY 1, 2011 RATES					Annual Increase/Decrease		
		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bil
1	**LOWER MAINLAND SERVICE AREA**													
2	Delivery Margin Related Charges													
3	Basic Charge	12	months x	$132.52	=	$1,590.24	12	months x	$132.52	=	$1,590.24	$0.00	$0.00	0.00%
4														
5	Delivery Charge	2,800.0	GJ x	$2.136	=	5,980.8000	2,800.0	GJ x	$2.397	=	6,711.6000	$0.261	730.8000	2.78%
6	Rider 3 ESM	2,800.0	GJ x	($0.079)	=	(221.2000)	2,800.0	GJ x	($0.027)	=	(75.6000)	$0.052	145.6000	0.55%
7	Rider 4 Delivery Rate Refund	2,800.0	GJ x	($0.021)	=	(58.8000)	2,800.0	GJ x	$0.000	=	0.00	$0.021	58.8000	0.22%
8	Rider 5 RSAM	2,800.0	GJ x	$0.001	=	2.8000	2,800.0	GJ x	($0.052)	=	(145.6000)	($0.053)	(148.4000)	-0.57%
9	Subtotal Delivery Margin Related Charges					**$7,293.84**					**$8,080.64**		**$786.80**	**3.00%**
10														
11	Commodity Related Charges													
12	Midstream Cost Recovery Charge	2,800.0	GJ x	$0.830	=	$2,324.0000	2,800.0	GJ x	$0.830	=	$2,324.0000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	2,800.0	GJ x	($0.021)	=	(58.8000)	2,800.0	GJ x	($0.021)	=	(58.8000)	$0.000	0.0000	0.00%
14	Midstream Related Charges Subtotal					$2,265.20					$2,265.20		$0.00	0.00%
15														
16	Cost of Gas (Commodity Cost Recovery Charge)	2,800.0	GJ x	$5.962	=	$16,693.60	2,800.0	GJ x	$5.962	=	$16,693.60	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges					**$18,958.80**					**$18,958.80**		**$0.00**	**0.00%**
18														
19	Total *(with effective $/GJ rate)*	2,800.0		*$9.376*		**$26,252.64**	2,800.0		*$9.657*		**$27,039.44**	*$0.281*	**$786.80**	**3.00%**
20														
21	**INLAND SERVICE AREA**													
22	Delivery Margin Related Charges													
23	Basic Charge	12	months x	$132.52	=	$1,590.24	12	months x	$132.52	=	$1,590.24	$0.00	$0.00	0.00%
24														
25	Delivery Charge	2,600.0	GJ x	$2.136	=	5,553.6000	2,600.0	GJ x	$2.397	=	6,232.2000	$0.261	678.6000	2.78%
26	Rider 3 ESM	2,600.0	GJ x	($0.079)	=	(205.4000)	2,600.0	GJ x	($0.027)	=	(70.2000)	$0.052	135.2000	0.55%
27	Rider 4 Delivery Rate Refund	2,600.0	GJ x	($0.021)	=	(54.6000)	2,600.0	GJ x	$0.000	=	0.00	$0.021	54.6000	0.22%
28	Rider 5 RSAM	2,600.0	GJ x	$0.001	=	2.6000	2,600.0	GJ x	($0.052)	=	(135.2000)	($0.053)	(137.8000)	-0.56%
29	Subtotal Delivery Margin Related Charges					**$6,886.44**					**$7,617.04**		**$730.60**	**2.99%**
30														
31	Commodity Related Charges													
32	Midstream Cost Recovery Charge	2,600.0	GJ x	$0.796	=	$2,069.6000	2,600.0	GJ x	$0.796	=	$2,069.6000	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	2,600.0	GJ x	($0.021)	=	(54.6000)	2,600.0	GJ x	($0.021)	=	(54.6000)	$0.000	0.0000	0.00%
34	Midstream Related Charges Subtotal					$2,015.00					$2,015.00		$0.00	0.00%
35														
36	Cost of Gas (Commodity Cost Recovery Charge)	2,600.0	GJ x	$5.962	=	$15,501.20	2,600.0	GJ x	$5.962	=	$15,501.20	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges					**$17,516.20**					**$17,516.20**		**$0.00**	**0.00%**
38														
39	Total *(with effective $/GJ rate)*	2,600.0		*$9.386*		**$24,402.64**	2,600.0		*$9.667*		**$25,133.24**	*$0.281*	**$730.60**	**2.99%**
40														
41	**COLUMBIA SERVICE AREA**													
42	Delivery Margin Related Charges													
43	Basic Charge	12	months x	$132.52	=	$1,590.24	12	months x	$132.52	=	$1,590.24	$0.00	$0.00	0.00%
44														
45	Delivery Charge	3,300.0	GJ x	$2.136	=	7,048.8000	3,300.0	GJ x	$2.397	=	7,910.1000	$0.261	861.3000	2.80%
46	Rider 3 ESM	3,300.0	GJ x	($0.079)	=	(260.7000)	3,300.0	GJ x	($0.027)	=	(89.1000)	$0.052	171.6000	0.56%
47	Rider 4 Delivery Rate Refund	3,300.0	GJ x	($0.021)	=	(69.3000)	3,300.0	GJ x	$0.000	=	0.00	$0.021	69.3000	0.23%
48	Rider 5 RSAM	3,300.0	GJ x	$0.001	=	3.3000	3,300.0	GJ x	($0.052)	=	(171.6000)	($0.053)	(174.9000)	-0.57%
49	Subtotal Delivery Margin Related Charges					**$8,312.34**					**$9,239.64**		**$927.30**	**3.01%**
50														
51	Commodity Related Charges													
52	Midstream Cost Recovery Charge	3,300.0	GJ x	$0.873	=	$2,880.9000	3,300.0	GJ x	$0.873	=	$2,880.9000	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	3,300.0	GJ x	($0.021)	=	(69.3000)	3,300.0	GJ x	($0.021)	=	(69.3000)	$0.000	0.0000	0.00%
54	Midstream Related Charges Subtotal					$2,811.60					$2,811.60		$0.00	0.00%
55														
56	Cost of Gas (Commodity Cost Recovery Charge)	3,300.0	GJ x	$5.962	=	$19,674.60	3,300.0	GJ x	$5.962	=	$19,674.60	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges					**$22,486.20**					**$22,486.20**		**$0.00**	**0.00%**
58														
59	Total *(with effective $/GJ rate)*	3,300.0		*$9.333*		**$30,798.54**	3,300.0		*$9.614*		**$31,725.84**	*$0.281*	**$927.30**	**3.01%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

RATE SCHEDULE 4 - SEASONAL SERVICE

Line No.	Particular	EFFECTIVE APRIL 1, 2009 Volume		Rate	Annual $	PROPOSED JANUARY 1, 2011 RATES Volume		Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bil
1												
2	**LOWER MAINLAND SERVICE AREA**											
3	Delivery Margin Related Charges											
4	Basic Charge	7	months x	$439.00 =	$3,073.00	7	months x	$439.00 =	$3,073.00	$0.00	$0.00	0.00%
5												
6	Delivery Charge											
7	(a) Off-Peak Period	5,400.0	GJ x	$0.762 =	4,114.8000	5,400.0	GJ x	$0.897 =	4,843.8000	$0.135	729.0000	1.71%
8	(b) Extension Period	0.0	GJ x	$1.539 =	0.0000	0.0	GJ x	$1.674 =	0.0000	$0.135	0.0000	0.00%
9	Rider 3 ESM	5,400.0	GJ x	($0.061) =	(329.4000)	5,400.0	GJ x	($0.011) =	(59.4000)	$0.050	270.0000	0.63%
10	Rider 4 Delivery Rate Refund	5,400.0	GJ x	($0.001) =	(5.4000)	5,400.0	GJ x	$0.000 =	0.0000	$0.001	5.4000	0.01%
11	Subtotal Delivery Margin Related Charges				**$6,853.00**				**$7,857.40**		**$1,004.40**	**2.35%**
12												
13	Commodity Related Charges											
14	Midstream Cost Recovery Charge											
15	(a) Off-Peak Period	5,400.0	GJ x	$0.670 =	$3,618.0000	5,400.0	GJ x	$0.670 =	$3,618.0000	$0.000	$0.0000	0.00%
16	(b) Extension Period	0.0	GJ x	$0.670 =	0.0000	0.0	GJ x	$0.670 =	0.0000	$0.000	0.0000	0.00%
17	Commodity Cost Recovery Charge											
18	(a) Off-Peak Period	5,400.0	GJ x	$5.962 =	32,194.8000	5,400.0	GJ x	$5.962 =	32,194.8000	$0.000	0.0000	0.00%
19	(b) Extension Period	0.0	GJ x	$5.962 =	0.0000	0.0	GJ x	$5.962 =	0.0000	$0.000	0.0000	0.00%
20												
21	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak				**$35,812.80**				**$35,812.80**		**$0.00**	**0.00%**
22												
23	Unauthorized Gas Charge During Peak Period (not forecast)											
24												
25	Total during Off-Peak Period	5,400.0			**$42,665.80**	5,400.0			**$43,670.20**		**$1,004.40**	**2.35%**
26												
27												
28	**INLAND SERVICE AREA**											
29	Delivery Margin Related Charges											
30	Basic Charge	7	months x	$439.00 =	$3,073.00	7	months x	$439.00 =	$3,073.00	$0.00	$0.00	0.00%
31												
32	Delivery Charge											
33	(a) Off-Peak Period	9,300.0	GJ x	$0.762 =	7,086.6000	9,300.0	GJ x	$0.897 =	8,342.1000	$0.135	1,255.5000	1.77%
34	(b) Extension Period	0.0	GJ x	$1.539 =	0.0000	0.0	GJ x	$1.674 =	0.0000	$0.135	0.0000	0.00%
35	Rider 3 ESM	9,300.0	GJ x	($0.061) =	(567.3000)	9,300.0	GJ x	($0.011) =	(102.3000)	$0.050	465.0000	0.65%
36	Rider 4 Delivery Rate Refund	9,300.0	GJ x	($0.001) =	(9.3000)	9,300.0	GJ x	$0.000 =	0.0000	$0.001	9.3000	0.01%
37	Subtotal Delivery Margin Related Charges				**$9,583.00**				**$11,312.80**		**$1,729.80**	**2.44%**
38												
39	Commodity Related Charges											
40	Midstream Cost Recovery Charge											
41	(a) Off-Peak Period	9,300.0	GJ x	$0.644 =	$5,989.2000	9,300.0	GJ x	$0.644 =	$5,989.2000	$0.000	$0.0000	0.00%
42	(b) Extension Period	0.0	GJ x	$0.644 =	0.0000	0.0	GJ x	$0.644 =	0.0000	$0.000	0.0000	0.00%
43	Commodity Cost Recovery Charge											
44	(a) Off-Peak Period	9,300.0	GJ x	$5.962 =	55,446.6000	9,300.0	GJ x	$5.962 =	55,446.6000	$0.000	0.0000	0.00%
45	(b) Extension Period	0.0	GJ x	$5.962 =	0.0000	0.0	GJ x	$5.962 =	0.0000	$0.000	0.0000	0.00%
46												
47	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak				**$61,435.80**				**$61,435.80**		**$0.00**	**0.00%**
48												
49	Unauthorized Gas Charge During Peak Period (not forecast)											
50												
51	Total during Off-Peak Period	9,300.0			**$71,018.80**	9,300.0			**$72,748.60**		**$1,729.80**	**2.44%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

RATE SCHEDULE 5 -GENERAL FIRM SERVICE

Line No.	Particular	EFFECTIVE APRIL 1, 2009 Volume		Rate		Annual $	PROPOSED JANUARY 1, 2011 RATES Volume		Rate		Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bil
1														
2	**LOWER MAINLAND SERVICE AREA**													
3	Delivery Margin Related Charges													
4	Basic Charge	12	months x	$587.00	=	**$7,044.00**	12	months x	$587.00	=	**$7,044.00**	$0.00	**$0.00**	**0.00%**
5														
6	Demand Charge	58.5	GJ x	$14.655	=	**$10,287.81**	58.5	GJ x	$16.504	=	**$11,585.81**	$1.849	**$1,298.00**	**1.50%**
7														
8	Delivery Charge	9,700.0	GJ x	$0.593	=	$5,752.1000	9,700.0	GJ x	$0.668	=	$6,479.6000	$0.075	$727.5000	0.84%
9	Rider 3 ESM	9,700.0	GJ x	($0.060)	=	(582.0000)	9,700.0	GJ x	($0.020)	=	(194.0000)	$0.040	388.0000	0.45%
10	Rider 4 Delivery Rate Refund	9,700.0	GJ x	($0.018)	=	(174.6000)	9,700.0	GJ x	$0.000	=	0.0000	$0.018	174.6000	0.20%
11	Subtotal Delivery Margin Related Charges					**$4,995.50**					**$6,285.60**		**$1,290.10**	**1.49%**
12														
13	Commodity Related Charges													
14	Midstream Cost Recovery Charge	9,700.0	GJ x	$0.670	=	$6,499.0000	9,700.0	GJ x	$0.670	=	$6,499.0000	$0.000	$0.0000	0.00%
15	Commodity Cost Recovery Charge	9,700.0	GJ x	$5.962	=	57,831.4000	9,700.0	GJ x	$5.962	=	57,831.4000	$0.000	0.0000	0.00%
16	Subtotal Gas Commodity Cost (Commodity Related Charge)					**$64,330.40**					**$64,330.40**		**$0.00**	**0.00%**
17														
18	Total *(with effective $/GJ rate)*	9,700.0		*$8.934*		**$86,657.71**	9,700.0		*$9.201*		**$89,245.81**	*$0.267*	**$2,588.10**	**2.99%**
19														
20	**INLAND SERVICE AREA**													
21	Delivery Margin Related Charges													
22	Basic Charge	12	months x	$587.00	=	**$7,044.00**	12	months x	$587.00	=	**$7,044.00**	$0.00	**$0.00**	**0.00%**
23														
24	Demand Charge	82.0	GJ x	$14.655	=	**$14,420.52**	82.0	GJ x	$16.504	=	**$16,239.94**	$1.849	**$1,819.42**	**1.62%**
25														
26	Delivery Charge	12,800.0	GJ x	$0.593	=	$7,590.4000	12,800.0	GJ x	$0.668	=	$8,550.4000	$0.075	$960.0000	0.85%
27	Rider 3 ESM	12,800.0	GJ x	($0.060)	=	(768.0000)	12,800.0	GJ x	($0.020)	=	(256.0000)	$0.040	512.0000	0.45%
28	Rider 4 Delivery Rate Refund	12,800.0	GJ x	($0.018)	=	(230.4000)	12,800.0	GJ x	$0.000	=	0.0000	$0.018	230.4000	0.20%
29	Subtotal Delivery Margin Related Charges					**$6,592.00**					**$8,294.40**		**$1,702.40**	**1.51%**
30														
31	Commodity Related Charges													
32	Midstream Cost Recovery Charge	12,800.0	GJ x	$0.644	=	$8,243.2000	12,800.0	GJ x	$0.644	=	$8,243.2000	$0.000	$0.0000	0.00%
33	Commodity Cost Recovery Charge	12,800.0	GJ x	$5.962	=	76,313.6000	12,800.0	GJ x	$5.962	=	76,313.6000	$0.000	0.0000	0.00%
34	Subtotal Gas Commodity Cost (Commodity Related Charge)					**$84,556.80**					**$84,556.80**		**$0.00**	**0.00%**
35														
36	Total *(with effective $/GJ rate)*	12,800.0		*$8.798*		**$112,613.32**	12,800.0		*$9.073*		**$116,135.14**	*$0.275*	**$3,521.82**	**3.13%**
37														
38	**COLUMBIA SERVICE AREA**													
39	Delivery Margin Related Charges													
40	Basic Charge	12	months x	$587.00	=	**$7,044.00**	12	months x	$587.00	=	**$7,044.00**	$0.00	**$0.00**	**0.00%**
41														
42	Demand Charge	55.4	GJ x	$14.655	=	**$9,742.64**	55.4	GJ x	$16.504	=	**$10,971.86**	$1.849	**$1,229.22**	**1.49%**
43														
44	Delivery Charge	9,100.0	GJ x	$0.593	=	$5,396.3000	9,100.0	GJ x	$0.668	=	$6,078.8000	$0.075	$682.5000	0.83%
45	Rider 3 ESM	9,100.0	GJ x	($0.060)	=	(546.0000)	9,100.0	GJ x	($0.020)	=	(182.0000)	$0.040	364.0000	0.44%
46	Rider 4 Delivery Rate Refund	9,100.0	GJ x	($0.018)	=	(163.8000)	9,100.0	GJ x	$0.000	=	0.0000	$0.018	163.8000	0.20%
47	Subtotal Delivery Margin Related Charges					**$4,686.50**					**$5,896.80**		**$1,210.30**	**1.47%**
48														
49	Commodity Related Charges													
50	Midstream Cost Recovery Charge	9,100.0	GJ x	$0.720	=	$6,552.0000	9,100.0	GJ x	$0.720	=	$6,552.0000	$0.000	$0.0000	0.00%
51	Commodity Cost Recovery Charge	9,100.0	GJ x	$5.962	=	54,254.2000	9,100.0	GJ x	$5.962	=	54,254.2000	$0.000	0.0000	0.00%
52	Subtotal Gas Commodity Cost (Commodity Related Charge)					**$60,806.20**					**$60,806.20**		**$0.00**	**0.00%**
53														
54	Total *(with effective $/GJ rate)*	9,100.0		$9.042		**$82,279.34**	9,100.0		$9.310		**$84,718.86**	*$0.268*	**$2,439.52**	**2.96%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

TERASEN GAS INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO. G-xx-09

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RATE SCHEDULE 6 - NGV - STATIONS

Line No.	Particular	EFFECTIVE APRIL 1, 2009					PROPOSED JANUARY 1, 2011 RATES					Annual Increase/Decrease		
1		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bil
2	**LOWER MAINLAND SERVICE AREA**													
3	Delivery Margin Related Charges													
4	Basic Charge	12	months x	$61.00	=	$732.00	12	months x	$61.00	=	$732.00	$0.00	$0.00	0.00%
5														
6	Delivery Charge	2,900.0	GJ x	$3.398	=	9,854.2000	2,900.0	GJ x	$3.754	=	10,886.6000	$0.356	1,032.4000	3.58%
7	Rider 3 ESM	2,900.0	GJ x	($0.110)	=	(319.0000)	2,900.0	GJ x	($0.033)	=	(95.7000)	$0.077	223.3000	0.77%
8	Rider 4 Delivery Rate Refund	2,900.0	GJ x	($0.019)	=	(55.1000)	2,900.0	GJ x	$0.000	=	0.0000	$0.019	55.1000	0.19%
9	Subtotal Delivery Margin Related Charges					**$10,212.10**					**$11,522.90**		**$1,310.80**	**4.54%**
10														
11	Commodity Related Charges													
12	Midstream Cost Recovery Charge	2,900.0	GJ x	$0.471	=	$1,365.9000	2,900.0	GJ x	$0.471	=	$1,365.9000	$0.000	$0.0000	0.00%
13	Commodity Cost Recovery Charge	2,900.0	GJ x	$5.962	=	17,289.8000	2,900.0	GJ x	$5.962	=	17,289.8000	$0.000	0.0000	0.00%
14	Subtotal Cost of Gas (Commodity Related Charge)					**$18,655.70**					**$18,655.70**		**$0.00**	**0.00%**
15														
16	Total *(with effective $/GJ rate)*	2,900.0		*$9.954*		**$28,867.80**	2,900.0		*$10.406*		**$30,178.60**	*$0.452*	**$1,310.80**	**4.54%**
17														
18														
19	**INLAND SERVICE AREA**													
20	Delivery Margin Related Charges													
21	Basic Charge	12	months x	$61.00	=	$732.00	12	months x	$61.00	=	$732.00	$0.00	$0.00	0.00%
22														
23	Delivery Charge	11,900.0	GJ x	$3.398	=	40,436.2000	11,900.0	GJ x	$3.754	=	44,672.6000	$0.356	4,236.4000	3.66%
24	Rider 3 ESM	11,900.0	GJ x	($0.110)	=	(1,309.0000)	11,900.0	GJ x	($0.033)	=	(392.7000)	$0.077	916.3000	0.79%
25	Rider 4 Delivery Rate Refund	11,900.0	GJ x	($0.019)	=	(226.1000)	11,900.0	GJ x	$0.000	=	0.0000	$0.019	226.1000	0.20%
26	Subtotal Delivery Margin Related Charges					**$39,633.10**					**$45,011.90**		**$5,378.80**	**4.64%**
27														
28	Commodity Related Charges													
29	Midstream Cost Recovery Charge	11,900.0	GJ x	$0.446	=	$5,307.4000	11,900.0	GJ x	$0.446	=	$5,307.4000	$0.000	$0.0000	0.00%
30	Commodity Cost Recovery Charge	11,900.0	GJ x	$5.962	=	70,947.8000	11,900.0	GJ x	$5.962	=	70,947.8000	$0.000	0.0000	0.00%
31	Subtotal Cost of Gas (Commodity Related Charge)					**$76,255.20**					**$76,255.20**		**$0.00**	**0.00%**
32														
33	Total *(with effective $/GJ rate)*	11,900.0		*$9.739*		**$115,888.30**	11,900.0		*$10.191*		**$121,267.10**	*$0.452*	**$5,378.80**	**4.64%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

TERASEN GAS INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO. G-xx-09

RATE SCHEDULE 7 - INTERRUPTIBLE SALES

Line No.	Particular	EFFECTIVE APRIL 1, 2009			PROPOSED JANUARY 1, 2011 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bil
2	**LOWER MAINLAND SERVICE AREA**									
3	Delivery Margin Related Charges									
4	Basic Charge	12 months x	$880.00 =	**$10,560.00**	12 months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
5										
6	Delivery Charge	8,100.0 GJ x	$0.990 =	$8,019.0000	8,100.0 GJ x	$1.110 =	$8,991.0000	$0.120	$972.0000	1.35%
7	Rider 3 ESM	8,100.0 GJ x	($0.036) =	(291.6000)	8,100.0 GJ x	($0.012) =	(97.2000)	$0.024	194.4000	0.27%
8	Rider 4 Delivery Rate Refund	8,100.0 GJ x	$0.000 =	0.0000	8,100.0 GJ x	$0.000 =	0.0000	$0.000	0.0000	0.00%
9	Subtotal Delivery Margin Related Charges			**$7,727.40**			**$8,893.80**		**$1,166.40**	**1.62%**
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge	8,100.0 GJ x	$0.670 =	$5,427.0000	8,100.0 GJ x	$0.670 =	$5,427.0000	$0.000	$0.0000	0.00%
13	Commodity Cost Recovery Charge	8,100.0 GJ x	$5.962 =	48,292.2000	8,100.0 GJ x	$5.962 =	48,292.2000	$0.000	0.0000	0.00%
14	Subtotal Gas Sales - Fixed (Commodity Related Charge)			**$53,719.20**			**$53,719.20**		**$0.00**	**0.00%**
15										
16	Non-Standard Charges (not forecast)									
17	Index Pricing Option, UOR									
18										
19	Total *(with effective $/GJ rate)*	8,100.0	*$8.890*	**$72,006.60**	8,100.0	*$9.034*	**$73,173.00**	*$0.144*	**$1,166.40**	**1.62%**
20										
21										
22	**INLAND SERVICE AREA**									
23	Delivery Margin Related Charges									
24	Basic Charge	12 months x	$880.00 =	**$10,560.00**	12 months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
25										
26	Delivery Charge	4,000.0 GJ x	$0.990 =	$3,960.0000	4,000.0 GJ x	$1.110 =	$4,440.0000	$0.120	$480.0000	1.18%
27	Rider 3 ESM	4,000.0 GJ x	($0.036) =	(144.0000)	4,000.0 GJ x	($0.012) =	(48.0000)	$0.024	96.0000	0.24%
28	Rider 4 Delivery Rate Refund	4,000.0 GJ x	$0.000 =	0.0000	4,000.0 GJ x	$0.000 =	0.0000	$0.000	0.0000	0.00%
29	Subtotal Delivery Margin Related Charges			**$3,816.00**			**$4,392.00**		**$576.00**	**1.41%**
30										
31	Commodity Related Charges									
32	Midstream Cost Recovery Charge	4,000.0 GJ x	$0.644 =	$2,576.0000	4,000.0 GJ x	$0.644 =	$2,576.0000	$0.000	$0.0000	0.00%
33	Commodity Cost Recovery Charge	4,000.0 GJ x	$5.962 =	23,848.0000	4,000.0 GJ x	$5.962 =	23,848.0000	$0.000	0.0000	0.00%
34	Subtotal Gas Sales - Fixed (Commodity Related Charge)			**$26,424.00**			**$26,424.00**		**$0.00**	**0.00%**
35										
36	Non-Standard Charges (not forecast)									
37	Index Pricing Option, UOR									
38										
39	Total *(with effective $/GJ rate)*	4,000.0	*$10.200*	**$40,800.00**	4,000.0	*$10.344*	**$41,376.00**	*$0.144*	**$576.00**	**1.41%**

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TERASEN GAS INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO. G-xx-09

RATE SCHEDULE 22 - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	EFFECTIVE APRIL 1, 2009 Volume		Rate		Annual $	PROPOSED JANUARY 1, 2011 RATES Volume		Rate		Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Annual Bil
1														
2	**LOWER MAINLAND SERVICE AREA**													
3	Basic Charge	12	months x	$3,664.00	=	**$43,968.00**	12	months x	$3,664.00	=	**$43,968.00**	$0.00	**$0.00**	**0.00%**
4														
5														
6	Delivery Charge - Interruptible MTQ	467,305.6	GJ x	$0.733	=	$342,535.0048	467,305.6	GJ x	$0.813	=	$379,919.4528	$0.080	$37,384.4480	9.99%
7	Rider 3 ESM	467,305.6	GJ x	($0.023)	=	(10,748.0288)	467,305.6	GJ x	($0.008)	=	(3,738.4448)	$0.015	7,009.5840	1.87%
8	Rider 4 Delivery Rate Refund	467,305.6	GJ x	($0.005)	=	(2,336.5280)	467,305.6	GJ x	$0.000	=	0.00	$0.005	2,336.5280	0.62%
9	Transportation - Interruptible					**$329,450.45**					**$376,181.01**		**$46,730.56**	**12.48%**
10														
11														
12	Non-Standard Charges (not forecast)													
13	UOR, Demand Surcharge, Balancing Service, Backstopping Gas													
14														
15														
16	Administration Charge	12	months x	$78.00	=	**$936.00**	12	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
17														
18														
19	Total *(with effective $/GJ rate)*	467,305.6		*$0.801*		**$374,354.45**	467,305.6		*$0.901*		**$421,085.01**	*$0.100*	**$46,730.56**	**12.48%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

TERASEN GAS INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO. G-xx-09

RATE SCHEDULE 22A - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	EFFECTIVE APRIL 1, 2009				PROPOSED JANUARY 1, 2011 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bil
2	**INLAND SERVICE AREA**											
3	Basic Charge	12	months x	$4,810.00	= **$57,720.00**	12	months x	$4,810.00	= **$57,720.00**	$0.00	**$0.00**	**0.00%**
4												
5												
6	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,595.4	GJ x	$11.765	= **$366,418.56**	2,595.4	GJ x	$13.071	= **$407,093.64**	$1.306	**$40,675.08**	**8.39%**
7												
8												
9	Delivery Charge - Firm MTQ	584,475.8	GJ x	$0.082	= $47,927.0156	584,475.8	GJ x	$0.091	= $53,187.2978	$0.009	$5,260.2822	1.09%
10	Rider 3 ESM	584,475.8	GJ x	($0.022)	= (12,858.4676)	584,475.8	GJ x	($0.008)	= (4,675.8064)	$0.014	8,182.6612	1.69%
11	Rider 4 Delivery Rate Refund	584,475.8	GJ x	($0.003)	= (1,753.4274)	584,475.8	GJ x	$0.000	= 0.0000	$0.003	1,753.4274	0.36%
12	Transportation - Firm (Delivery Charge Firm MTQ)				**$33,315.12**				**$48,511.49**		**$15,196.37**	**3.14%**
13												
14												
15	Delivery Charge - Interruptible MTQ	28,607.9	GJ x	$0.939	= $26,862.8181	28,607.9	GJ x	$1.031	= $29,494.7449	$0.092	$2,631.9268	0.54%
16	Rider 3 ESM	28,607.9	GJ x	($0.022)	= (629.3738)	28,607.9	GJ x	($0.008)	= (228.8632)	$0.014	400.5106	0.08%
17	Rider 4 Delivery Rate Refund	28,607.9	GJ x	($0.003)	= (85.8237)	28,607.9	GJ x	$0.000	= 0.0000	$0.003	85.8237	0.02%
18	Transportation - Interruptible (Delivery Charge Interruptible MTQ)				**$26,147.62**				**$29,265.88**		**$3,118.26**	**0.64%**
19												
20												
21	Non-Standard Charges (not forecast)											
22	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
23												
24												
25	Administration Charge	12	months x	$78.00	= **$936.00**	12	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
26												
27												
28	Total *(with effective $/GJ rate)*	584,475.8		*$0.829*	**$484,537.30**	584,475.8		*$0.930*	**$543,527.01**	*$0.101*	**$58,989.71**	**12.17%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

RATE SCHEDULE 22B - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	EFFECTIVE APRIL 1, 2009				PROPOSED JANUARY 1, 2011 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bil
2	**COLUMBIA SERVICE - EXCEPT ELKVIEW COAL**											
3	Basic Charge	12	months x	$4,537.00 =	**$54,444.00**	12	months x	$4,537.00 =	**$54,444.00**	$0.00	**$0.00**	**0.00%**
4												
5	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,211.8	GJ x	$7.496 =	**$198,955.80**	2,211.8	GJ x	$8.296 =	**$220,189.08**	$0.800	**$21,233.28**	**7.42%**
6												
7	Delivery Charge - Firm MTQ	457,345.8	GJ x	$0.080 =	$36,587.6640	457,345.8	GJ x	$0.089 =	$40,703.7762	$0.009	$4,116.1122	1.44%
8	Rider 3 ESM	457,345.8	GJ x	($0.018) =	(8,232.2244)	457,345.8	GJ x	($0.005) =	(2,286.7290)	$0.013	5,945.4954	2.08%
9	Rider 4 Delivery Rate Refund	457,345.8	GJ x	($0.003) =	(1,372.0374)	457,345.8	GJ x	$0.000 =	0.0000	$0.003	1,372.0374	0.48%
10	Transportation - Firm (Delivery Charge Firm MTQ)				**$26,983.40**				**$38,417.05**		**$11,433.65**	**3.99%**
11												
12	Delivery Charge - Interruptible MTQ											
13	- Apr. 1 to Nov. 1	6,732.4	GJ x	$0.747 =	$5,029.1028	6,732.4	GJ x	$0.827 =	$5,567.6948	$0.080	$538.5920	0.19%
14	- Nov. 1 to Apr. 1	0.0	GJ x	$1.076 =	0.0000	0.0	GJ x	$1.191 =	0.0000	$0.115	0.0000	0.00%
15	Rider 3 ESM	6,732.4	GJ x	($0.018) =	(121.1832)	6,732.4	GJ x	($0.005) =	(33.6620)	$0.013	87.5212	0.03%
16	Rider 4 Delivery Rate Refunc	6,732.4	GJ x	($0.003) =	(20.1972)	6,732.4	GJ x	$0.000 =	0.0000	$0.003	20.1972	0.01%
17	Transportation - Interruptible (Delivery Charge Interruptible MTQ				**$4,887.72**				**$5,534.03**		**$646.31**	**0.23%**
18												
19	Non-Standard Charges (not forecast)											
20	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
21												
22	Administration Charge	12	months x	$78.00 =	**$936.00**	12	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
23												
24	Total *(with effective $/GJ rate)*	464,078.2		*$0.617*	**$286,206.92**	464,078.2		*$0.689*	**$319,520.16**	*$0.072*	**$33,313.24**	**11.64%**
25												
26												
27	**COLUMBIA SERVICE - ELKVIEW COAL**											
28	Basic Charge	12	months x	$4,537.00 =	**$54,444.00**	12	months x	$4,537.00 =	**$54,444.00**	$0.00	**$0.00**	**0.00%**
29												
30	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,670.0	GJ x	$1.702 =	**$54,532.08**	2,670.0	GJ x	$1.884 =	**$60,363.36**	$0.182	**$5,831.28**	**3.69%**
31												
32	Delivery Charge - Firm MTQ	631,553.5	GJ x	$0.080 =	$50,524.2800	631,553.5	GJ x	$0.089 =	$56,208.2615	$0.009	$5,683.9815	3.60%
33	Rider 3 ESM	631,553.5	GJ x	($0.007) =	(4,420.8745)	631,553.5	GJ x	($0.002) =	(1,263.1070)	$0.005	3,157.7675	2.00%
34	Rider 4 Delivery Rate Refunc	631,553.5	GJ x	($0.003) =	(1,894.6605)	631,553.5	GJ x	$0.000 =	0.0000	$0.003	1,894.6605	1.20%
35	Transportation - Firm (Delivery Charge Firm MTQ)				**$44,208.75**				**$54,945.15**		**$10,736.40**	**6.80%**
36												
37	Delivery Charge - Interruptible MTQ											
38	- Apr. 1 to Nov. 1	0.0	GJ x	$0.187 =	$0.0000	0.0	GJ x	$0.207 =	$0.0000	$0.020	$0.0000	0.00%
39	- Nov. 1 to Apr. 1	14,503.1	GJ x	$0.267 =	3,872.3277	14,503.1	GJ x	$0.295 =	4,278.4145	$0.028	406.0868	0.26%
40	Rider 3 ESM	14,503.1	GJ x	($0.007) =	(101.5217)	14,503.1	GJ x	($0.002) =	(29.0062)	$0.005	72.5155	0.05%
41	Rider 4 Delivery Rate Refunc	14,503.1	GJ x	($0.003) =	(43.5093)	14,503.1	GJ x	$0.000 =	0.0000	$0.003	43.5093	0.03%
42	Transportation - Interruptible (Delivery Charge Interruptible MTQ				**$3,727.30**				**$4,249.41**		**$522.11**	**0.33%**
43												
44	Non-Standard Charges (not forecast)											
45	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
46												
47	Administration Charge	12	months x	$78.00 =	**$936.00**	12	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
48												
49	Total *(with effective $/GJ rate)*	646,056.6		*$0.244*	**$157,848.13**	646,056.6		*$0.271*	**$174,937.92**	*$0.027*	**$17,089.79**	**10.83%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

RATE SCHEDULE 23 - LARGE COMMERCIAL T-SERVICE

Line No.	Particular	EFFECTIVE APRIL 1, 2009 Volume		Rate		Annual $	PROPOSED JANUARY 1, 2011 RATES Volume		Rate		Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Annual Bil
1														
2	**LOWER MAINLAND SERVICE AREA**													
3	Basic Charge	12	months x	$132.52	=	**$1,590.24**	12	months x	$132.52	=	**$1,590.24**	$0.00	**$0.00**	**0.00%**
4														
5	Administration Charge	12	months x	$78.00	=	**$936.00**	12	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
6														
7	Delivery Charge	4,100.0	GJ x	$2.136	=	$8,757.6000	4,100.0	GJ x	$2.397	=	$9,827.7000	$0.261	$1,070.1000	9.84%
8	Rider 3 ESM	4,100.0	GJ x	($0.079)	=	(323.9000)	4,100.0	GJ x	($0.027)	=	(110.7000)	$0.052	213.2000	1.96%
9	Rider 4 Delivery Rate Refunc	4,100.0	GJ x	($0.022)	=	(90.2000)	4,100.0	GJ x	$0.000	=	0.0000	$0.022	90.2000	0.83%
10	Rider 5 RSAM	4,100.0	GJ x	$0.001	=	4.1000	4,100.0	GJ x	($0.052)	=	(213.2000)	($0.053)	(217.3000)	-2.00%
11	Transportation - Firm					**$8,347.60**					**$9,503.80**		**$1,156.20**	**10.63%**
12														
13	Non-Standard Charges (not forecast)													
14	UOR, Balancing gas, Backstopping Gas, Replacement Gas													
15														
16	Total *(with effective $/GJ rate)*	4,100.0		*$2.652*		**$10,873.84**	4,100.0		*$2.934*		**$12,030.04**	*$0.282*	**$1,156.20**	**10.63%**
17														
18	**INLAND SERVICE AREA**													
19	Basic Charge	12	months x	$132.52	=	**$1,590.24**	12	months x	$132.52	=	**$1,590.24**	$0.00	**$0.00**	**0.00%**
20														
21	Administration Charge	12	months x	$78.00	=	**$936.00**	12	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
22														
23	Delivery Charge	4,700.0	GJ x	$2.136	=	$10,039.2000	4,700.0	GJ x	$2.397	=	$11,265.9000	$0.261	$1,226.7000	10.14%
24	Rider 3 ESM	4,700.0	GJ x	($0.079)	=	(371.3000)	4,700.0	GJ x	($0.027)	=	(126.9000)	$0.052	244.4000	2.02%
25	Rider 4 Delivery Rate Refund	4,700.0	GJ x	($0.022)	=	(103.4000)	4,700.0	GJ x	$0.000	=	0.0000	$0.022	103.4000	0.85%
26	Rider 5 RSAM	4,700.0	GJ x	$0.001	=	4.7000	4,700.0	GJ x	($0.052)	=	(244.4000)	($0.053)	(249.1000)	-2.06%
27	Transportation - Firm					**$9,569.20**					**$10,894.60**		**$1,325.40**	**10.96%**
28														
29	Non-Standard Charges (not forecast)													
30	UOR, Balancing gas, Backstopping Gas, Replacement Gas													
31														
32	Total *(with effective $/GJ rate)*	4,700.0		*$2.573*		**$12,095.44**	4,700.0		*$2.855*		**$13,420.84**	*$0.282*	**$1,325.40**	**10.96%**
33														
34	**COLUMBIA SERVICE AREA**													
35	Basic Charge	12	months x	$132.52	=	**$1,590.24**	12	months x	$132.52	=	**$1,590.24**	$0.00	**$0.00**	**0.00%**
36														
37	Administration Charge	12	months x	$78.00	=	**$936.00**	12	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
38														
39	Delivery Charge	4,200.0	GJ x	$2.136	=	$8,971.2000	4,200.0	GJ x	$2.397	=	$10,067.4000	$0.261	$1,096.2000	9.90%
40	Rider 3 ESM	4,200.0	GJ x	($0.079)	=	(331.8000)	4,200.0	GJ x	($0.027)	=	(113.4000)	$0.052	218.4000	1.97%
41	Rider 4 Delivery Rate Refunc	4,200.0	GJ x	($0.022)	=	(92.4000)	4,200.0	GJ x	$0.000	=	0.0000	$0.022	92.4000	0.83%
42	Rider 5 RSAM	4,200.0	GJ x	$0.001	=	4.2000	4,200.0	GJ x	($0.052)	=	(218.4000)	($0.053)	(222.6000)	-2.01%
43	Transportation - Firm					**$8,551.20**					**$9,735.60**		**$1,184.40**	**10.69%**
44														
45	Non-Standard Charges (not forecast)													
46	UOR, Balancing gas, Backstopping Gas, Replacement Gas													
47														
48	Total *(with effective $/GJ rate)*	4,200.0		*$2.637*		**$11,077.44**	4,200.0		*$2.919*		**$12,261.84**	*$0.282*	**$1,184.40**	**10.69%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

RATE SCHEDULE 25 - GENERAL FIRM T-SERVICE

Line No.	Particular	EFFECTIVE APRIL 1, 2009 Volume		Rate	Annual $	PROPOSED JANUARY 1, 2011 RATES Volume		Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Annual Bil
1												
2	**LOWER MAINLAND SERVICE AREA**											
3	Basic Charge	12	months x	$587.00 =	**$7,044.00**	12	months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
4												
5	Administration Charge	12	months x	$78.00 =	**$936.00**	12	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
6												
7	Transportation - Firm Demand	97.2	GJ x	$14.655 =	**$17,093.64**	97.2	GJ x	$16.504 =	**$19,250.28**	$1.849	**$2,156.64**	**6.16%**
8												
9	Delivery Charge	19,086.2	GJ x	$0.593 =	$11,318.1166	19,086.2	GJ x	$0.668 =	$12,749.5816	$0.075	$1,431.4650	4.09%
10	Rider 3 ESM	19,086.2	GJ x	($0.060) =	(1,145.1720)	19,086.2	GJ x	($0.020) =	(381.7240)	$0.040	763.4480	2.18%
11	Rider 4 Delivery Rate Refund	19,086.2	GJ x	($0.012) =	(229.0344)	19,086.2	GJ x	$0.000 =	0.0000	$0.012	229.0344	0.65%
12	Transportation - Firm				**$9,943.91**				**$12,367.86**		**$2,423.95**	**6.92%**
13												
14	Non-Standard Charges (not forecast)											
15	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
16												
17	Total *(with effective $/GJ rate)*	19,086.2		*$1.835*	**$35,017.55**	19,086.2		*$2.075*	**$39,598.14**	*$0.240*	**$4,580.59**	**13.08%**
18												
19	**INLAND SERVICE AREA**											
20	Basic Charge	12	months x	$587.00 =	**$7,044.00**	12	months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
21												
22	Administration Charge	12	months x	$78.00 =	**$936.00**	12	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
23												
24	Transportation - Firm Demand	212.6	GJ x	$14.655 =	**$37,387.80**	212.6	GJ x	$16.504 =	**$42,105.00**	$1.849	**$4,717.20**	**7.09%**
25												
26	Delivery Charge	40,670.5	GJ x	$0.593 =	$24,117.6065	40,670.5	GJ x	$0.668 =	$27,167.8940	$0.075	$3,050.2875	4.58%
27	Rider 3 ESM	40,670.5	GJ x	($0.060) =	(2,440.2300)	40,670.5	GJ x	($0.020) =	(813.4100)	$0.040	1,626.8200	2.44%
28	Rider 4 Delivery Rate Refund	40,670.5	GJ x	($0.012) =	(488.0460)	40,670.5	GJ x	$0.000 =	0.0000	$0.012	488.0460	0.73%
29	Transportation - Firm				**$21,189.33**				**$26,354.48**		**$5,165.15**	**7.76%**
30												
31	Non-Standard Charges (not forecast)											
32	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
33												
34	Total *(with effective $/GJ rate)*	40,670.5		*$1.636*	**$66,557.13**	40,670.5		*$1.879*	**$76,439.48**	*$0.243*	**$9,882.35**	**14.85%**
35												
36	**COLUMBIA SERVICE**											
37	Basic Charge	12	months x	$587.00 =	**$7,044.00**	12	months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
38												
39	Administration Charge	12	months x	$78.00 =	**$936.00**	12	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
40												
41	Transportation - Firm Demand	182.2	GJ x	$14.655 =	**$32,041.68**	182.2	GJ x	$16.504 =	**$36,084.36**	$1.849	**$4,042.68**	**7.24%**
42												
43	Delivery Charge	30,357.8	GJ x	$0.593 =	$18,002.1754	30,357.8	GJ x	$0.668 =	$20,279.0104	$0.075	$2,276.8350	4.08%
44	Rider 3 ESM	30,357.8	GJ x	($0.060) =	(1,821.4680)	30,357.8	GJ x	($0.020) =	(607.1560)	$0.040	1,214.3120	2.17%
45	Rider 4 Delivery Rate Refund	30,357.8	GJ x	($0.012) =	(364.2936)	30,357.8	GJ x	$0.000 =	0.0000	$0.012	364.2936	0.65%
46	Transportation - Firm				**$15,816.41**				**$19,671.85**		**$3,855.44**	**6.90%**
47												
48	Non-Standard Charges (not forecast)											
49	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
50												
51	Total *(with effective $/GJ rate)*	30,357.8		*$1.839*	**$55,838.09**	30,357.8		*$2.100*	**$63,736.21**	*$0.261*	**$7,898.12**	**14.14%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

TERASEN GAS INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO. G-xx-09

RATE SCHEDULE 27 - INTERRUPTIBLE T-SERVICE

Line No.	Particular	EFFECTIVE APRIL 1, 2009 Volume		Rate	Annual $	PROPOSED JANUARY 1, 2011 RATES Volume		Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Annual Bil
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bil
2	**LOWER MAINLAND SERVICE AREA**											
3	Basic Charge	12	months x	$880.00 =	**$10,560.00**	12	months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
4												
5	Administration Charge	12	months x	$78.00 =	**$936.00**	12	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
6												
7	Delivery Charge	53,957.0	GJ x	$0.990 =	$53,417.4300	53,957.0	GJ x	$1.110 =	$59,892.2700	$0.120	$6,474.8400	10.35%
8	Rider 3 ESM	53,957.0	GJ x	($0.036) =	(1,942.4520)	53,957.0	GJ x	($0.012) =	(647.4840)	$0.024	1,294.9680	2.07%
9	Rider 4 Delivery Rate Refund	53,957.0	GJ x	($0.008) =	(431.6560)	53,957.0	GJ x	$0.000 =	0.0000	$0.008	431.6560	0.69%
10	Transportation - Interruptible				**$51,043.32**				**$59,244.79**		**$8,201.47**	**13.11%**
11												
12	Non-Standard Charges (not forecast)											
13	UOR, Balancing gas, Backstopping Gas											
14												
15	Total *(with effective $/GJ rate)*	53,957.0		*$1.159*	**$62,539.32**	53,957.0		*$1.311*	**$70,740.79**	*$0.152*	**$8,201.47**	**13.11%**
16												
17												
18	**INLAND SERVICE AREA**											
19	Basic Charge	12	months x	$880.00 =	**$10,560.00**	12	months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
20												
21	Administration Charge	12.0	months x	$78.00 =	**$936.00**	12.0	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
22												
23	Delivery Charge	48,903.9	GJ x	$0.990 =	$48,414.8610	48,903.9	GJ x	$1.110 =	$54,283.3290	$0.120	$5,868.4680	10.16%
24	Rider 3 ESM	48,903.9	GJ x	($0.036) =	(1,760.5404)	48,903.9	GJ x	($0.012) =	(586.8468)	$0.024	1,173.6936	2.03%
25	Rider 4 Delivery Rate Refund	48,903.9	GJ x	($0.008) =	(391.2312)	48,903.9	GJ x	$0.000 =	0.0000	$0.008	391.2312	0.68%
26	Transportation - Interruptible				**$46,263.09**				**$53,696.48**		**$7,433.39**	**12.87%**
27												
28												
29	Non-Standard Charges (not forecast)											
30	UOR, Balancing gas, Backstopping Gas											
31		48,903.9		*$1.181*	**$57,759.09**	48,903.9		*$1.333*	**$65,192.48**	*$0.152*	**$7,433.39**	**12.87%**
32	Total *(with effective $/GJ rate)*											
33												
34												
35	**COLUMBIA SERVICE AREA**											
36	Basic Charge	12	months x	$880.00 =	**$10,560.00**	12	months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
37												
38	Administration Charge	12.0	months x	$78.00 =	**$936.00**	12.0	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
39												
40	Delivery Charge	7,733.8	GJ x	$0.990 =	$7,656.4620	7,733.8	GJ x	$1.110 =	$8,584.5180	$0.120	$928.0560	1.61%
41	Rider 3 ESM	7,733.8	GJ x	($0.036) =	(278.4168)	7,733.8	GJ x	($0.012) =	(92.8056)	$0.024	185.6112	0.32%
42	Rider 4 Delivery Rate Refund	7,733.8	GJ x	($0.008) =	(61.8704)	7,733.8	GJ x	$0.000 =	0.0000	$0.008	61.8704	0.11%
43	Transportation - Interruptible				**$7,316.17**				**$8,491.71**		**$1,175.54**	**2.04%**
44												
45												
46	Non-Standard Charges (not forecast)											
47	UOR, Balancing gas, Backstopping Gas											
48		7,733.8		*$2.432*	**$18,812.17**	7,733.8		*$2.584*	**$19,987.71**	*$0.152*	**$1,175.54**	**2.04%**
49	Total *(with effective $/GJ rate)*											

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

TERASEN GAS INC. - INLAND SERVICE AREA (APPLICABLE TO REVELSTOKE CUSTOMERS)
EFFECT ON REVELSTOKE RATE SCHEDULE 1, 2, AND 3 CUSTOMERS' WITH RATE CHANGES
BCUC ORDER NO. G-xx-09

Line No.	PARTICULARS	EXISTING JULY 1, 2009 RATES					PROPOSED JANUARY 1, 2011 RATES					Annual Increase/Decrease		
1	**INLAND SERVICE AREA**	Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bil
2														
3	**Rate 1 - Residential**													
4	Delivery Margin Related Charges													
5	Basic Charge	12	months x	$11.84	=	$142.08	12	months x	$11.84	=	$142.08	$0.00	$0.00	0.00%
6														
7	Delivery Charge	50.0	GJ x	$2.961	=	148.0500	50.0	GJ x	$3.413	=	170.6500	$0.452	22.6000	2.55%
8	Rider 3 ESM	50.0	GJ x	($0.132)	=	(6.6000)	50.0	GJ x	($0.046)	=	(2.3000)	$0.086	4.3000	0.48%
9	Rider 4 Lochburn Land Sale Rebate	50.0	GJ x	($0.035)	=	(1.7500)	50.0	GJ x	$0.000	=	0.00	$0.035	1.7500	0.20%
10	Rider 5 RSAM	50.0	GJ x	$0.001	=	0.0500	50.0	GJ x	($0.052)	=	(2.6000)	($0.053)	(2.6500)	-0.30%
11	Subtotal Delivery Margin Related Charges			$2.795		**$281.83**			$3.315		**$307.83**		**$26.00**	**2.93%**
12														
13	Commodity Related Charges													
14	Midstream Cost Recovery Charge	50.0	GJ x	$0.903	=	$45.1500	50.0	GJ x	$0.903	=	$45.1500	$0.000	$0.0000	0.00%
15	Cost of Gas	50.0	GJ x	$5.962	=	298.1000	50.0	GJ x	$5.962	=	298.1000	$0.000	0.0000	0.00%
16	Rider 1 Propane Surcharge	50.0	GJ x	$5.231	=	261.5500	50.0	GJ x	$5.231	=	261.5500	$0.000	0.0000	0.00%
17	Subtotal Commodity Related Charges			$12.096		**$604.80**			$12.096		**$604.80**		**$0.00**	**0.00%**
18														
19	*Total (with effective $/GJ rate)*	50.0		*$17.733*		**$886.63**	50.0		*$18.253*		**$912.63**	*$0.520*	**$26.00**	**2.93%**
20														
21	**Rate 2 - Small Commercial**													
22	Delivery Margin Related Charges													
23	Basic Charge	12	months x	$24.84	=	$298.08	12	months x	$24.84	=	$298.08	$0.00	$0.00	0.00%
24														
25	Delivery Charge	250.0	GJ x	$2.479	=	619.7500	250.0	GJ x	$2.814	=	703.5000	$0.335	83.7500	2.30%
26	Rider 3 ESM	250.0	GJ x	($0.100)	=	(25.0000)	250.0	GJ x	($0.034)	=	(8.5000)	$0.066	16.5000	0.45%
27	Rider 4 Lochburn Land Sale Rebate	250.0	GJ x	($0.029)	=	(7.2500)	250.0	GJ x	$0.000	=	0.00	$0.029	7.2500	0.20%
28	Rider 5 RSAM	250.0	GJ x	$0.001	=	0.2500	250.0	GJ x	($0.052)	=	(13.0000)	($0.053)	(13.2500)	-0.36%
29	Subtotal Delivery Margin Related Charges			$2.351		**$885.83**			$2.728		**$980.08**		**$94.25**	**2.59%**
30														
31	Commodity Related Charges													
32	Midstream Cost Recovery Charge	250.0	GJ x	$0.907	=	$226.7500	250.0	GJ x	$0.907	=	$226.7500	$0.000	$0.0000	0.00%
33	Cost of Gas	250.0	GJ x	$5.962	=	1,490.5000	250.0	GJ x	$5.962	=	1,490.5000	$0.000	0.0000	0.00%
34	Rider 1 Propane Surcharge	250.0	GJ x	$4.136	=	1,034.0000	250.0	GJ x	$4.136	=	1,034.0000	$0.000	0.0000	0.00%
35	Subtotal Commodity Related Charges			$11.005		**$2,751.25**			$11.005		**$2,751.25**		**$0.00**	**0.00%**
36														
37	*Total (with effective $/GJ rate)*	250.0		*$14.548*		**$3,637.08**	250.0		*$14.925*		**$3,731.33**	*$0.377*	**$94.25**	**2.59%**
38														
39	**Rate 3 - Large Commercial**													
40	Delivery Margin Related Charges													
41	Basic Charge	12	months x	$132.52	=	$1,590.24	12	months x	$132.52	=	$1,590.24	$0.00	$0.00	0.00%
42														
43	Delivery Charge	4,500.0	GJ x	$2.136	=	9,612.0000	4,500.0	GJ x	$2.397	=	10,786.5000	$0.261	1,174.5000	1.95%
44	Rider 3 ESM	4,500.0	GJ x	($0.079)	=	(355.5000)	4,500.0	GJ x	($0.027)	=	(121.5000)	$0.052	234.0000	0.39%
45	Rider 4 Lochburn Land Sale Rebate	4,500.0	GJ x	($0.021)	=	(94.5000)	4,500.0	GJ x	$0.000	=	0.00	$0.021	94.5000	0.16%
46	Rider 5 RSAM	4,500.0	GJ x	$0.001	=	4.5000	4,500.0	GJ x	($0.052)	=	(234.0000)	($0.053)	(238.5000)	-0.40%
47	Subtotal Delivery Margin Related Charges			$2.037		**$10,756.74**			$2.318		**$12,021.24**		**$1,264.50**	**2.10%**
48														
49	Commodity Related Charges													
50	Midstream Cost Recovery Charge	4,500.0	GJ x	$0.796	=	$3,582.0000	4,500.0	GJ x	$0.796	=	$3,582.0000	$0.000	$0.0000	0.00%
51	Cost of Gas	4,500.0	GJ x	$5.962	=	26,829.0000	4,500.0	GJ x	$5.962	=	26,829.0000	$0.000	0.0000	0.00%
52	Rider 1 Propane Surcharge	4,500.0	GJ x	$4.247	=	19,111.5000	4,500.0	GJ x	$4.247	=	19,111.5000	$0.000	0.0000	0.00%
53	Subtotal Commodity Related Charges			$11.005		**$49,522.50**			$11.005		**$49,522.50**		**$0.00**	**0.00%**
54														
55	*Total (with effective $/GJ rate)*	4,500.0		*$13.395*		**$60,279.24**	4,500.0		*$13.676*		**$61,543.74**	*$0.281*	**$1,264.50**	**2.10%**

Notes: Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations.
Slight differences in totals due to rounding

Appendix K

REFERENCED RELEVANT PREVIOUS DECISIONS

(view Attachments Panel in Adobe
to access Contents of Appendix K)

REFERENCED RELEVANT PREVIOUS DECISIONS AND ORDERS

Major Terasen Gas Decisions Referenced

TGI 1998-2000 PBR Decision and **One-Year PBR Extension for 2001** - Order No. G-85-97 dated July 23, 1997 and Order No. G-48-00 dated May 4, 2000.

TGI 2003 Revenue Requirement Application Decision - Order No. G-7-03, dated February 4, 2003.

TGI 2004-2007 PBR Decision and Settlement Agreement - Order No. G-51-03, dated July 29, 2003.

TGI-TGVI Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism - Decision - Order No. G-14-06 dated March 2, 2006

Two-Year Extension of the 2004-2007 Multi-Year Performance-Based Rate Plan - Order No. G-33-07, dated March 22, 2007.

TGI - TGVI System Extension and Customer Connection Policies Review Decision - Order No. G-152-07 dated December 6, 2007

TGI-TGVI Energy Efficiency and Conservation ("EEC") Application Decision - Order No. G-36-09 dated April 16, 2009.

Commission Orders Referenced:

Orders are sorted by Order type and in numerical order by Order No. (not by year).

CPCN ("C") Orders

Order No. C-2-09 dated March 12, 2009 - CPCN for the Fraser River Crossing Upgrade Project

Order No. C-5-07 dated July 5, 2007 and Reasons for Decision dated August 2, 2007 - CPCN for the Distribution Mobile Solution ("DMS") Project

Order No. C-6-06 and Reasons for Decision dated August 14, 2006 - CPCN for the Commodity Unbundling Project for Residential Customers

General ("G") Orders

Order No. G-7-03 and Reasons for Decision dated February 4, 2003 - TGI 2003 Revenue Requirement Application Decision

Order No. G-14-06 and Reasons for Decision dated March 2, 2006 - TGI-TGVI ROE and Capital Structure and review of BCUC Generic Mechanism

Order No. G-23-09 dated March 12, 2009 - TGI 2009 First Quarter Gas Cost review - the order approved TGI commodity cost decreases of $1.574/GJ effective April 1, 2009.

Order No. G-24-09 dated March 12, 2009 - Revelstoke Propane 2009 First Quarter Gas Cost review - propane commodity cost decreases of $.1077/litre ($4.150/GJ) approved effective April 1, 2009.

Order No. G-25-04 dated March 12, 2004, Commodity Unbundling and Customer Choice Phase 1 - Cost Allocation. In keeping with the Essential Services Model described in the Application the order and decision approved the separation of gas costs into commodity costs and midstream costs. The then-existing gas cost deferral mechanism - the Gas Cost Reconciliation Account ("GCRA") was replaced by two accounts the Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA").

Order No. G-33-07 dated March 22, 2007. The order approved the Application for Approval of a Two-year Extension of the 2004-2007 Multi-Year Performance-Based Rate Plan for 2008-2009.

Order No. G-35-09 and Reasons for Decision dated April 7, 2009. Terasen Gas (Whistler) Inc. - Application for 2009 Revenue Requirements, Return on Equity and Capital Structure

Order No. G-36-09 and Reasons for Decision dated April 16, 2009 - Decision and order on TGI-TGVI Energy Efficiency and Conservation ("EEC") Application.

Order No. G-44-09 dated April 30, 2009 approved the application for an extension of Rate Schedule 14A, except that the requested treatment of

Order No. G-51-03 and Reasons for Decision dated July 29, 2003 approved the 2004 - 2007 Multi-Year Performance-Based Rate Plan and Settlement Agreement.

Order No. G-53-94 dated July 14, 1994 approves Regulatory Accounting Guidelines for Natural Gas Utilities

General ("G") Orders (continued)

Order No. G-59-94 and Reasons for Decision dated August 4, 1994 (Phase 2 of the 1994/95 Revenue Requirements Application) approved the Revenue Stabilization Adjustment Mechanism ("RSAM").

Order No. G-66-08 dated April 10, 2008 granted approval for TGI to issue up to $600 million of MTN Debentures until the end of May 2010.

Order No. G-72-90 dated October 9, 1990 approved the establishment of the Revelstoke Propane Cost Deferral Account

Order No. G-80-03 dated December 11, 2003 and Reasons for Decision dated December 17, 2003. This order approved delivery rates for TGI for 2004, the first year of the 2004 - 2007 PBR Plan.

Order No. G-85-97 and Reasons for Decision dated July 23, 1997. This order approved the 1998 - 2000 Performance Based Rate Plan and Settlement Agreement.

Order No. G-90-03 dated December 23, 2005. This order approved Rules for Natural Gas Marketers effective January 1, 2004, and the commencement of Commodity Unbundling for Commercial customers and a Stable Rate Offering for Residential customers effective April 1, 2004.

Order No. G-95-00 dated October 5, 2000 approved of a Financing Plan for the Southern Crossing Pipeline Project

Order No. G-98-05 dated October 5, 2005 approved the Terasen Gas Inc. application for approval of transactions related to the Southern Crossing Pipeline but denied the recovery of Inland Pacific Connector development costs

Order No. G-98-99 dated September 16, 1999 approved amendments to the TGI Natural Gas Vehicle ("NGV") Grant Program and the associated Rate Schedule 6 tariff changes

Order No. G-108-01 dated October 17, 2001 approved the Lease-In Lease-Out ("LILO") lease arrangements with the City of Kelowna

Order No. G-112-04 dated December 15, 2004 approved TGI's 2005 Revenue Requirement Application and delivery rate decreases determined according to the 2004 - 2007 PBR Plan Settlement provisions.

Order No. G-112-07 dated September 20, 2007 established the regulatory timetable for a combined review of the TGI 2007 Annual Review and the TGVI 2007 Settlement Update

General ("G") Orders (continued)

Order No. G-121-06 dated October 2, 2006 established a combined regulatory timetable for the TGI 2006 Annual Review and Mid-Term Assessment Review of the 2004 - 2007 PBR Plan

Order No. G-123-01 and Reasons for Decision dated November 21, 2001 approved TGI's application to withdraw its 2002 Revenue Requirements Application.

Order No. G-124-00 dated December 28, 2000 approved delivery rates for 2001 arising from the 2000 Annual Review Process and December 6, 200 Revenue Requirements Application.

Order No. G-124-08 dated August 28, 2008 and Reasons for Decision dated September 24, 2008 - BC Hydro - approved a Residential Inclining Block ("RIB") rate structure for BC Hydro's residential customer class.

Order No. G-127-08 dated September 11, 2008 approved for TGI a $2.244/GJ commodity cost decrease effective October 1, 2008 based on the review of TGI's third quarter 2008 gas cost report.

Order No. G-132-05 and Reasons for Decision dated December 14, 2005 approved TGI's 2006 Revenue Requirement Application following the 2005 Annual Review process.

Order No. G-135-99 dated December 21, 1999 approved TGI's 2000 Revenue Requirements Application as determined according to the provisions of the 1998 - 2000 PBR Settlement Agreement.

Order No. G-142-08 dated September 25, 2008 established the joint regulatory review timetable for the TGI 2008 Annual Review and the TGVI 2008 Settlement Update.

Order No. G-152-07 and Reasons for Decision dated December 6, 2007 approved changes to the Main Extension ("MX") and Customer Connection policies of TGI and TGVI following a written hearing and regulatory review process.

Order No. G-153-07 and Reasons for Decision dated December 10, 2007 approved 2008 Revenue Requirements and delivery rates following the 2007 Annual Review process.

Order No. G-160-06 dated December 18, 2006 approved TGI's 2007 Revenue Requirements and delivery rates following the 2006 Annual Review process

General ("G") Orders (continued)

Order No. G-189-08 dated December 12, 2008 approved a Revelstoke propane commodity decrease of $0.2067/litre or $7.732/GJ following the fourth quarter propane cost review process.

Order No. G-191-08 dated December 11, 2008 approved TGI's 2009 Revenue Requirements and delivery rates following the 2008 Annual Review process.

Order No. G-194-08 dated December 15, 2008 accepted for filing the 2008 combined Resource Plan of TGI, TGVI and TGW.

Letters ("L")

Letter No. L-5-01 dated February 5, 2001 established Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Balance. These Guidelines set out, among other things, the quarterly commodity review process, the amortization period for commodity deferral account balances and the 95% / 105% trigger threshold parameters for determining when a commodity cost flowthrough is warranted.

Letter No. L-55-08 dated November 20, 2008 established a 2009 return on equity ("ROE") of 8.47% for the low risk benchmark utility using the Commission's generic ROE mechanism.

Letter No. L-64-97 dated October 16, 1997 approved the Terasen Gas Code of Conduct and Transfer Pricing Policy governing the relationships between the Utility and Non-regulated Businesses ("NRBs").